TRANSITIONAL ACCESS ALLOCATION PROJECT

FOR THE NATIONAL ELECTRICITY MARKET

PUBLISHED: **JUNE 2014**

IMPORTANT NOTICE

Purpose

AEMO has prepared this document to provide information about transitional access allocation under a proposed methodology as part of the Australian Energy Market Commission's optional firm access design.

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EXECUTIVE SUMMARY

Following a request for assistance from the AEMC, AEMO has demonstrated a proposed methodology for allocating transitional access under the proposed optional firm access model.

The objectives of the demonstration were to confirm the feasibility of the proposed methodology to determine the maximum simultaneously feasible supply in each region. The approach is consistent with that described in section 12.6.2 of the Transmission Frameworks Review Technical Report: Optional Firm Access.

AEMO used its existing systems to produce the results, including the National Electricity Market Dispatch Engine (NEMDE), existing NEMDE input files and internal staff and resources. AEMC laid out the overall approach, and all emergent issues were discussed and agreed with them before proceeding.

Key features of the methodology

- The NEMDE is used to determine transitional access (TA) allocation for scheduled and semi-scheduled generators, using modified input files from actual dispatch cases.
- A ‘dummy’ load is applied at the regional reference node and dispatched to find the maximum simultaneously feasible network capacity for the modified case.
- A base scenario at the most recent summer peak demand and six sensitivity scenarios are studied to test the methodology under winter peak and off-peak, and various offer profile, weather, plant and network constraint conditions. Multiple base scenarios are also performed to test the stability of the model under slightly different conditions.
- TA is initially allocated with generators’ and Basslink offers set to dispatch them at maximum output with interconnectors at zero.
- Interconnectors are then allocated ‘residual’ TA, with generators and Basslink held at their initial TA allocations. In practice, there was no residual available except on interconnectors into Victoria. With the AEMC’s agreement, this was not considered important to model as part of this demonstration.

Reporting and modelling issues

AEMO produced detailed and summary results for use by the AEMC and its industry working group. The results were summarised into 19 sub-regions that were determined from the base scenario results and geographical spread of generators within the sub-regions. The summary results from this demonstration are included in this report.

AEMO considered a number of modelling issues while undertaking this work are discussed in the report. These issues have either been addressed by AEMO or have been identified for further consideration by the AEMC.

Results

The base scenarios results are aggregated into 19 sub-regions to assist with interpreting the outcomes. The results showed TA allocation in excess of 90% in 14 sub-regions. The summary results of the base scenario are shown in Table 1.

Options for further analysis

- Repeat studies without the recently deregistered Wallerawang No.7 unita recently deregistered unit in NSW, which would be expected to allow some additional access to generators in the NSW Snowy sub-region.
- Modifying the methodology to share the TA allocation differently.
- Alternative methodologies proposed by members of the AEMC’s industry working group.

AEMO is willing to develop these options further with AEMC staff.

Table 1 Base Scenario Results

Sub-Region	Allocation	Limiting Constraints
Northern Queensland	100%	
Central Queensland	99%	Local connection limits
Brisbane	100%	
South Western Queensland	84%	Upper limit of 4500 MW imposed by AEMO (removed April 2014)
Hunter Valley NSW	100%	
Central Coast NSW	100%	
Sydney	100%	
Western NSW	100%	
Southern NSW	100%	
NSW Snowy	63%	Flow from Bannaby to Sydney West for loss of Dapto to Sydney South.
Victoria Snowy	100%	
Northern Victoria	87%	Flow into Dederang flow loss of connection to Melbourne
Latrobe Valley	95%	Hazelwood 500 kV transformation
Melbourne	86%	Supply to the Victorian outer grid
Western Victoria	100%	
South-Eastern South Australia	90%	Flows into Adelaide
Adelaide	100%	
Northern South Australia	97%	Flows into Adelaide
Tasmania	63%	Tasmania's hydro is energy limited with higher relative capacity than other regions.

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1 BACKGROUND

The Optional Firm Access (OFA) model requires that a transitional access (TA) allocation is established, which determines the initial level of TA allocated to existing generators at the commencement of the OFA regime. This initial access allocation will be set at a level so that each Transmission Network Service Provider (TNSP) is firm access standard (FAS) compliant at OFA commencement.

The AEMC have requested AEMO undertake work to demonstrate a proposed method for allocating transitional access based on principles and method set out in the Transmission Frameworks Review Final Report and the Technical Report: Optional Firm Access. In its request, the AEMC identified two changes to the method identified in the final report – there would not be different peak and off-peak allocations, and only system peak dispatch studies would be required.

AEMO has undertaken the studies with the following objectives in mind:

- Generators are to receive transitional access that represents their current access level on the network.
- AEMO would develop a methodology that may be used at the initiation of optional firm access consistent with the recommendations in the Transmission Frameworks Review (TFR) Technical Report.
- Results from AEMO's studies are to be used for the purpose of reviewing and understanding the proposed methodology.

AEMO understands the objective is to demonstrate the methodology and not to calculate final results to be applied in real OFA settlement.

This document has been provided to the AEMC for the express purpose of assisting their understanding of the Transitional Access methodology proposed in the TFR. The reader is presumed to be familiar with detailed OFA concepts described in the TFR and details of the dispatch process.

2 METHODOLOGY

Readers are encouraged to first familiarise themselves with section 12.6.2 of the TFR Technical Report.

2.1 Dispatch Model

AEMO used NEM Dispatch Engine (NEMDE) input files from actual dispatch cases in the NEM. The cases used are listed in Appendix 1. Each input file was modified as follows:

- A ‘dummy’ scheduled load at the regional reference node added to allow maximum simultaneously feasible network capacity to be determined for each case, as described below.
- Dispatch inputs for generators and Basslink, demand distribution, network flows, network limits and weather conditions set as described below.
- Interconnector inputs set as described below.
- Scheduled loads not considered.
- A single scheduled load located at the regional reference node (RRN) priced at $1,000/MWh as described below.
- Demand distribution away from the RRN is determined by the specific case selected. In practice, this is achieved through network feedback constraint right hand sides which are based on measured line flows.

AEMO developed tools to automate the changes to the input files mentioned above and in the following sections. This permitted a practical and repeatable methodology that minimised the time to assemble each case and minimised the risk of human error.

The analysis is reported based on “as generated” or scheduled quantities. AEMO understands actual firm access will be defined based on “sent-out” or settlement quantities.

2.2 Generator and Interconnector Allocations

Generator and interconnector TA are calculated separately. This is done in two stages:

1. Calculate generator allocations for mainland regions with interconnector flows set to zero.
2. Calculate residual interconnector allocation with generators set to the levels determined in step 1.

Basslink was regarded as a generator and for the purposes of calculating TA allocations was given the same priority as generators.

Note: In practice, there was no residual available except on interconnectors into Victoria. With the AEMC’s agreement, this was not considered important to model as part of this demonstration.

2.3 Dispatch Inputs

Generators and Basslink

- Generator and Basslink availability: historical peak output over two years.
- Generator and Basslink bids: band prices set in $10/MWh increments from $10/MWh to $100/MWh; band sizes equal to 10% of the assigned availability (that is, 1st 10% of capacity offered at $10/MWh. 2nd 10% offered at $20/MWh and so on).
- The following plant constraints were modified to prevent them limiting the available energy output from generators:
  - Ramp rates set to very high values.
  - Fast-start profiles disabled.

- Wind forecast limits for semi-scheduled windfarms ignored (ie unconstrained intermittent generation forecast not enforced)
- FCAS trapeziums ignored

Semi-scheduled generators (principally wind) were treated in the same way as schedule generators.

Non-scheduled generators were not explicitly considered. In practice, non-scheduled generators offset demand conditions and are reflected in measured flows and generation that affect network constraint right-hand sides.

Network Constraints

System normal constraints only were used. FCAS, generator and network maintenance outage constraints were removed. The constraints applicable for operating the Victoria transmission network between the Latrobe Valley and Melbourne in radial mode and Yallourn unit one on the 220kV path were used and the Murray Switching Station to Upper Tumut Switching Station 330kV line was assumed out of service.

Constraint right-hand sides were determined by the sample case. See the discussion about feedback constraints below.

Manipulation of network constraints to add, remove or change network limits was found to be impractical. This is because the formulation of some constraints is complex and modifications would require considerable manual effort. The impact on AEMO's time frame the risk of introducing errors into the model ruled out changes this way.

Scheduled Loads

Pumps and scheduled loads were not dispatched in AEMO's analysis. Bid prices for scheduled loads are typically low and would not normally get dispatched at peak periods.

Demand Conditions

Determined by the dispatch cases selected. In practice, the distribution of demand is modelled through the use of network feedback constraints so that measured line flows and generation (and the resulting constraint right hand sides) serve as proxies for the distribution of demand.

Weather Conditions

Temperate and wind-speed were determined by the specific case selected. In practice, temperature and wind-speed influence line ratings (for lines using dynamic ratings) and the level of non-scheduled generation. In addition, non-scheduled generation will generally be higher during periods of high wind.

Loss Factors

Transmission intra-regional loss factors are modelled by scaling prices before they are loaded into NEMDE. For the TA modelling, prices were assumed to be scaled by loss factors so that all bids had the same values at the regional reference node.

Transmission inter-regional loss factor equations models were determined by the input cases. *Note: In practice, interconnectors were not modelled and so inter-regional transmission loss factor equations were not a factor.*

2.4 Scenarios

The sensitivity scenarios modelled are described in Table 2-1.

Table 2-1 —Summary of Scenario Modelling Assumptions

Scenario	Demand	Generation	Tiered bids	RRPs	Weather	Transmission
1. Base Scenario	Summer peak 2013/14 50% POE	All those operating in Summer 2013/14	From $10 In $10/MWh increments	Region, $1000/MWh; neighbouring regions $0/MWh	High temp; low wind	2013/14 system normal
2. Steeper taper	As per base	As per base	From $100 in $100 increments	As per base	As per base	As per base
3. Off-peak sensitivity	Summer weekly minimum	As per base	As per base	As per base	As per base	As per base
4. Windy sensitivity	As per base	As per base	As per base	As per base	High wind (total NEM wind gen 1735 MW), Adelaide temp 39.9 C	High wind scenario to represent cooling effect of wind on network.
5. Winter sensitivity	Winter peak 2014 50% POE	As per base	As per base	As per base	Low temp; high wind	As per base
6. Mothballed generation	As per base	Include all generation that is not notified as closed	As per base	As per base	As per base	As per base
7. Flow gate Support	As per base	As per base	As per base	As per base	As per base	Generators with negative LHS factors removed from constraints.
8 Future Networks[1]	Summer peak 20xx 50% POE	Add committed generation for 20xx	As per base	As per base	As per base	Add 20xx system normal including committed transmission

AEMO also performed 80 runs with base scenario assumptions (that is, summer high demand periods) for the top demand periods since January 2014 to determine the variability of the results.

[1] AEMO was not able to develop network constraints for this scenario.

2.5 Regional Reference Node Load

A “dummy” scheduled load was added to each RRN and bid to $1000/MWh. As this is above the offer prices for generators, NEMDE dispatched this load fully subject to network constraints not being violated. This produced a maximum simultaneously feasible supply for each region based on the inputs described above.

2.6 Reporting

For each scenario, AEMO reported:

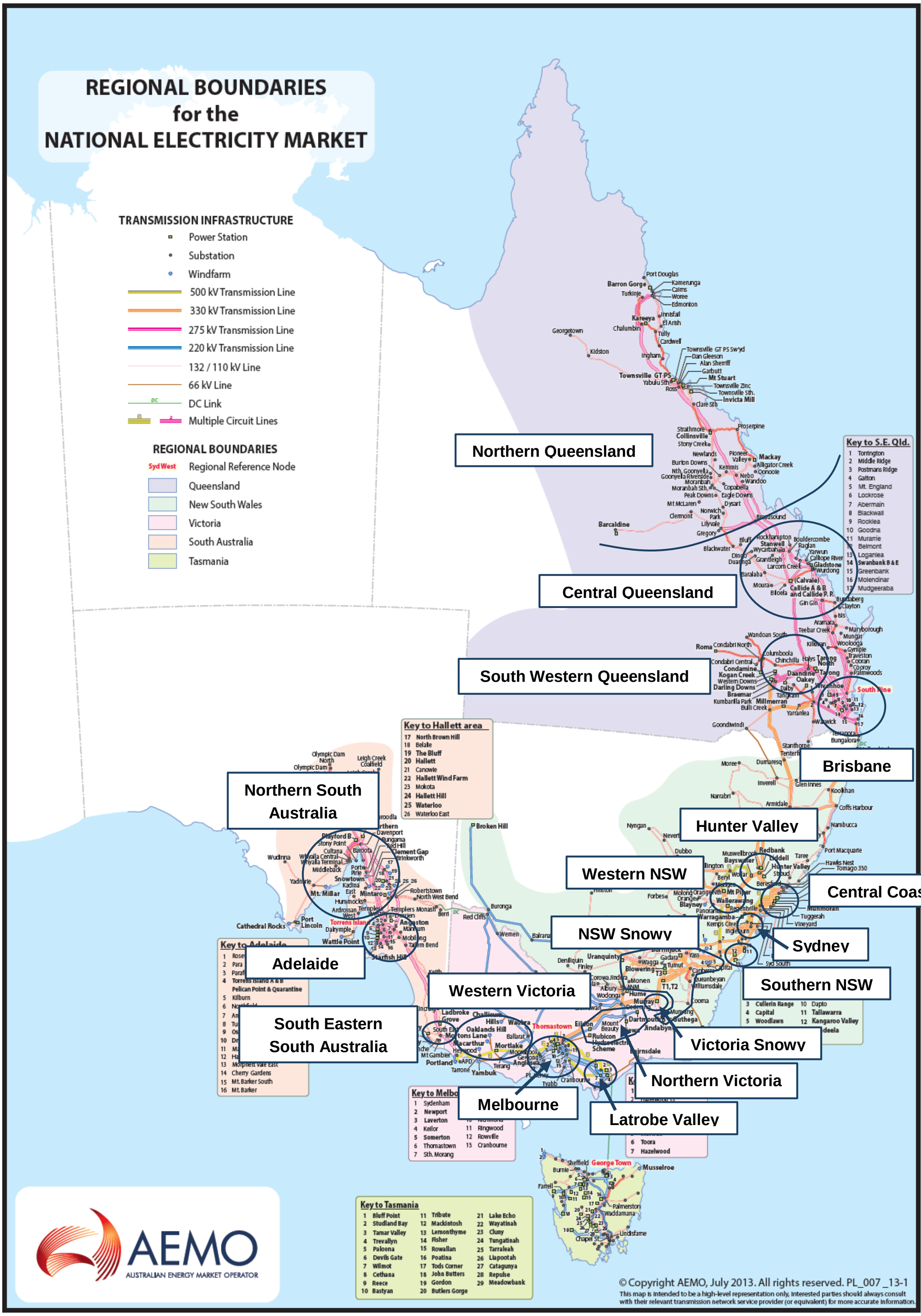
- For regions:
  - Total dispatched generation.
  - Regional reference price.
  - Additional load at the RRN dispatched under the TA methodology.
- For generators and Basslink:
  - Generator dispatchable unit ID (DUID).
  - Allocated capacity in MW.
  - TA allocation in MW as and a percentage of allocated capacity.
  - Left hand side (LHS) factors in binding constraints.
  - Local price (determined from regional reference price, constraint marginal value and LHS factor).
- For binding network constraints:
  - AEMO’s constraint ID.
  - Marginal cost in $/MWh for each constraint. (Note non-binding constraints have a zero marginal cost and were not reported.)

AEMO also aggregated generator data into sub-regions to summarise the results. AEMO provided a list of each generator and its allocated sub-region to the AEMC. The sub-regions for reporting are shown in Figure 2-1.

Note sub-regions are used to summarise the TA allocation for groups of generators and are similar to but not related to zones in AEMO’s National Transmission Network Development Plan, which describe NEM demand centres.[2]

[2] AEMO. *National Transmission Network Development Plan 2013*. Page 9, http://www.aemo.com.au/Electricity/Planning/~/media/Files/Electricity/Planning/Reports/NTNDP/2013/2013_NTNDP.pdf.ashx

Figure 2-1 —Transitional Access Allocation Sub-Regions



3 MODELLING ISSUES

3.1 Use of Single Dispatch Cases

Single dispatch cases have the advantage of being relatively simple to identify and manipulate and are based on real system conditions. They can be distorted by prevailing or unusual system conditions such as outages, disruptions, lines flows and patterns of generation.

The base case scenario chosen for this work occurred during heatwave conditions in Victoria and South Australia, and high temperatures in NSW and Queensland. The case was affected by a violating constraint relating to the Victorian outer grid. Otherwise the case was a suitable starting point for application of the methodology, with no prior network outages, normal distribution of demand around the network, and high levels of initial generation.

Care will need to be taken with the final allocation to identify a similarly suitable case. Alternative modelling approaches such as market modelling techniques or AEMO's NEM simulator to obtain statistically-based or controlled cases were not examined as part of this work.

3.2 Demand Distribution

NEMDE does not explicitly model demand distributions in a region and all demand that is not scheduled is treated as a single demand located at the RRN. The distribution of demand within a region will affect network losses and constraints. Network losses are modelled in the demand forecast. Network constraints impacts are modelled in the constraint formulations:

- In dispatch by measuring actual line flows, that is with feedback constraints.
- In predispatch by making assumptions about the distribution of the total region demand within a region.

AEMO used the dispatch formulation of the constraints. This meant the demand distribution about the region remained fixed while the additional demand applied using the methodology was applied at RRN. Had upstream loads been scaled up, there would be less congestion. The RRN approach is consistent with the methodology set out in the Technical Report which desired an estimate of congestion if all generators affected by each system normal constraint in turn were to attempt to simultaneously operate with upstream loads consistent with the dispatch case

The alternative predispatch formulation was not tested and would require considerable effort. The predispatch formulation would have the effect of proportionally increasing demand across the region. It should also be noted the demand distribution factors are approximate and do not take into account the relative responses of industrial, commercial and residential loads.

3.3 Constraint Formulation

3.3.1 Feedback Constraints

Dispatch constraint formulations use measured system conditions (line flows and generation) to model the post-contingency flow on critical lines and to obtain a simultaneously feasible dispatch and pricing solution. This approach was developed by NEMMCO[3] soon after commencement of the NEM and are described in the Constraint Formulation Guidelines published by AEMO.[4]

Feedback constraints operate by measuring the "headroom" available on a transmission line (that is, the difference between the rating of and the flow on the relevant line). In most cases, critical constraints are managing a critical contingency where the post-contingency flow is estimated by measuring the flow on two transmission lines – the

[3] National Electricity Market Management Company Limited, a predecessor of AEMO.

[4] AEMO. *Constraint Formulation Guidelines.* 5 December 2013. **http://www.aemo.com.au/Electricity/Market-Operations/Congestion-Information-Resource/Constraint-Formulation-Guidelines**

line that would trip and the line that may overload following the trip. The techniques for calculating the post-contingency flow use line flow redistribution factors[5] are well understood and have proved effective in managing power system security in the NEM.

Measured flows will also be affected by the prevailing interconnector flows that occurred at the time of the dispatch case being used. The methodology initially clamps each interconnector to zero in the solution. This means the contribution of each interconnector to the line flow will be allocated to generation within the region.

3.3.2 Flow Gate Support

Generation with negative LHS factors will tend to increase the amount of flow available through a flow gate. For example, this can occur where the generator's dispatch may cause a more favourable distribution of power across transmission lines in a flow gate, or by increasing overall levels of stability on a network. This results in supporting generators being constrained-on and other generators being constrained-off. AEMO studied the sensitivity of TA allocation to such constraints by removing them from the relevant network constraints.

In practice, there were two critical flow gates that AEMO identified:

- Supply to the Victoria outer grid where all generators in Northern Victoria and Victoria Snowy reduced flows (ie were constrained on). This constraint was violating and was not included in the flow gate scenario.
- Flow into Brisbane from south-western Queensland. Removal of flow gate support resulted in a general reduction in TA allocation to south-western Queensland generation.

3.3.3 Future Network Scenario

AEMO is not able to develop a constraint set to model future networks and the scenario was not calculated.

3.4 Network Changes

The study cases used the transmission network in place for the study conditions. Changes to the network have occurred between the winter and summer cases, and since the studies were undertaken. The most significant change was the removal of an AEMO-imposed upper limit on transfers from south-western Queensland into Brisbane in April 2014.

3.5 Tasmania

Hydro generation in Tasmania is energy limited and there is higher installed capacity in that region compared to other regions. The methodology does not consider this in determining TA allocation. Additionally, the regional reference node in Tasmania is not located at the Hobart load centre and the impact of this on the model's results may require further investigation.

3.6 Mothballed Generation

This scenario required AEMO to perform the base scenario but include registered generation that had not operated in the previous 2 years and insert its registered capacity. In practice, this only affected Playford B Power Station (Northern South Australia - 240 MW).

Munmorah Power Station units 3 and 4 (NSW central coast - 600 MW) had not operated but was deregistered on 29 May 2014 and was not modelled in the mothballed scenario.

[5] Also referred to line outage redistribution factors and can be determined with commercial load flow software, using DC loadflow techniques.

4 RESULTS

4.1 Base Scenario Results

4.1.1 Single Case Results

Table 4-1 —Summary of Base-Scenario TA Allocation

Sub-Region	Allocation	Limiting Constraints
Northern Queensland	100%	
Central Queensland	99%	Local connection limits
Brisbane	100%	
South Western Queensland	84%	Upper limit of 4500 MW imposed by AEMO (removed April 2014)
Hunter Valley NSW	100%	
Central Coast NSW	100%	
Sydney	100%	
Western NSW	100%	
Southern NSW	100%	
NSW Snowy	63%	Flow from Bannaby to Sydney West for loss of Dapto to Sydney South.
Victoria Snowy	100%	
Northern Victoria	87%	Flow into Dederang flow loss of connection to Melbourne
Latrobe Valley	95%	Hazelwood 500 kV transformation
Melbourne	86%	Supply to the Victorian outer grid
Western Victoria	100%	
South-Eastern South Australia	90%	Flows into Adelaide
Adelaide	100%	
Northern South Australia	97%	Flows into Adelaide
Tasmania	63%	Tasmania's hydro is energy limited with higher relative capacity than other regions.

NSW Snowy received the lowest TA allocation of all the mainland sub-regions. This was due to a constraint on flows into Sydney from the south. AEMO's Annual NEM Constraint Report 2013[6] did not report any internal NSW constraints in the top 20 binding constraints in the 2013 calendar year, so AEMO has examined in some detail this result. AEMO notes:

- There are few examples in recent years where all NSW generation has attempted to generate at full output. In NSW, flows from the south can be affected by northern generation as a result of the meshed design of the transmission network.
- The dispatch case chosen had a high but not extreme load across NSW. Note that under extreme conditions, , higher loads could be expected at locations remote from the RRN (such as Canberra and Newcastle).

[6] AEMO. *Annual NEM Constraint Report 2013*. 29 April 2014. **http://www.aemo.com.au/Electricity/Market-Operations/Dispatch/Annual-NEM-Constraint-Report**

- The recent upgrade of several NSW lines from 330 kV to 500 kV may have resulted in more flows on the limiting line than might have occurred before the upgrade. For example, the redistribution of flows on the outage line has increased from about 17% to 21% following the upgrade.

Figure 4-1 shows a diagram of the limiting network constraint in NSW.

Although there is little historical data to support the result, AEMO considers the result does reflect the network, supply and demand conditions being modelled. The subsequent retirement of Wallerawang Power Station No.7 unit will change this result, either by allowing additional supply from the south or by causing a different constraint to bind.

Access for Tasmania generators is also relatively low. This is explained in part by the high levels of energy limited hydro generation in that region. AEMO has also noted a modelling issue with modelling the additional load at the regional reference node which is not near the major load centre of Hobart.

Figure 4-1 —NSW Limiting Network Constraint

4.1.2 Multiple Peak Study

AEMO repeated the base scenario analysis for the highest 80 demands in summer. Table 4-2 summarises the outcomes for sub-regions with allocations that changed by more than 3%. Variability in these sub-regions was generally the same all units in the sub-region, except for units in Melbourne and Northern South Australia.

Variability within the NSW Snowy sub-region is consistent across all units and indicates the methodology is stable for the spread of power system conditions modelled. Variability in the Melbourne and Northern South Australia sub-regions is the result of localised conditions specific to those units. Variability in Northern Victoria and South Eastern South Australia require further investigation, although the absolute change in TA allocation at 5% is still relatively small.

Table 4-2 —Summary of Significant Multiple Peak Study Variations

Sub-Region	Allocation	Multiple Run Allocation	Standard Deviation
NSW Snowy	63%	57.4%	4.6
Northern Victoria	87%	90.4%	12.8
Melbourne	86%	95.3%	9.8
South Eastern South Australia	90%	86.7%	14.7
Northern South Australia	97%	86.7%	8.7

4.1.3 Interconnector Allocation

AEMO did not undertake allocation for interconnectors. The methodology requires that generation would be fixed at TA allocation levels before interconnector allocation is determined. This means any constrained-off generation on the same path as an interconnector would indicate no further access would be available across a flowgate path:

- TA from NSW into Queensland would have been zero given that South Western Queensland generation had already been constrained off.
- TA from Queensland to NSW would have been zero because interconnector flow would be distributed on the meshed network surrounding Sydney (see Figure 4-1), and would increase flow on the constrained line from Bannaby to Sydney West.
- TA from NSW to Victoria may have been possible given that Victoria Snowy was not constrained and Northern Victoria generation was constrained off by network limits into Victoria Snowy.
- TA from Victoria to NSW would have been zero given that NSW Snowy generation had already been constrained off.
- TA from Victoria to South Australia would have been zero given that South Eastern South Australia generation had already been constrained off.
- TA from South Australia may have been possible given that Western Victoria generation was not constrained.

4.2 Scenario Results

The scenario results showed, with some exceptions, TA allocations are broadly consistent across the scenarios:

- NSW Snowy Sub-Region has large variations in TA allocation across the different scenarios.
- South Eastern South Australia received lower TA allocation during the high wind summer scenario.

The tapered bid scenario would be expected to result in lower overall access as this scenario places a higher market value on constraining off lower priced bids, compared to the regional reference price.

The off-peak, high wind summer and winter scenarios produced different results compared to the base case. This could be due to differing line ratings in the cases and different demand distributions.

The mothballed generation case required calculating TA for Playford B Power Station. This station is located in Northern South Australia which reduced the overall allocation of TA in the South Australia Region.

The flowgate scenario involved removing Swanbank E from network constraints with a negative LHS factor for the unit. As a result, the overall access available in Queensland was reduced in this scenario.

Appendix 2 shows the differences in region demand modelled in each scenario. In general, each scenario resulted in equivalent or lower levels of access generally. The exceptions were the high-wind summer and winter peak scenarios, which resulted in high levels of TA allocated to generators in Victoria.

Table 4-3 —Summary of Scenario TA Allocations

Sub-Region	Base	Taper	Off-peak	Windy	Winter	Mothball	Flowgate
Northern Queensland	100%	100%	100%	100%	100%	100%	100%
Central Queensland	99%	99%	97%	97%	96%	99%	99%
Brisbane	100%	100%	100%	100%	100%	100%	100%
South Western Queensland	84%	84%	84%	85%	82%	84%	82%
Hunter Valley NSW	100%	97%	100%	100%	100%	100%	100%
Central Coast NSW	100%	100%	100%	100%	100%	100%	100%
Sydney	100%	100%	100%	100%	100%	100%	100%
Western NSW	100%	90%	100%	100%	100%	100%	100%
Southern NSW	100%	80%	99%	100%	100%	100%	100%
NSW Snowy	63%	73%	26%	48%	60%	63%	63%
Victoria Snowy	100%	100%	92%	96%	100%	100%	100%
Northern Victoria	87%	87%	100%	93%	100%	87%	87%
Latrobe Valley	95%	95%	91%	96%	95%	95%	95%
Melbourne	86%	86%	100%	100%	100%	86%	86%
Western Victoria	100%	100%	100%	100%	93%	100%	100%
South Eastern South Australia	90%	90%	88%	60%	74%	90%	90%
Adelaide	100%	100%	100%	100%	100%	100%	100%
Northern South Australia	97%	97%	90%	87%	86%	99%	97%

4.3 Further Analysis

Following presentation of the results, the AEMC has indicated further analysis would be desirable. This included:

- Calculating TA allocation with different price structures for generating units that were allocated TA below a certain threshold, say 70%.
- Calculating inter-regional TA allocation taking into account the revised capacity of the Heywood interconnection.
- Calculating TA allocation with Wallerawang No.7 unit removed.
- Revising the methodology as follows:
  - Optimse the base scenario with generation capacities and offers unchanged but without any changes in regional demand (step 1).
  - Run the base scenario with minimum constraints applied to all generators at the levels from step 1 (step 2).
- Members of the AEMC's industry working group have also suggested modifications and alternative methodologies.

This work is outside the scope of this demonstration and has not been studied.

5 CONCLUSIONS

Methodology

AEMO has demonstrated the application of the TA allocation methodology proposed in the OFA final report as modified by the AEMC. All elements of the methodology were modelled with the following exceptions:

- Interconnector TA allocation was not determined because critical flow paths were fully allocated to regional generators.
- Tasmania results require further investigation to determine whether location of the RRN in Tasmania is unsuitable for the methodology.
- A proposed future network scenario was not able to be modelled by using dispatch cases.
- Changes to network limits by manipulating the cases was not practical. This would need to be done manually, and would be slow and introduce risk of human errors in making the changes.

The methodology was found to be practical and repeatable.

Results

All results were explainable in terms of network limitations and appear to be consistent with the prevailing network conditions. Multiple runs of the base scenario for the 80 highest demand intervals since January 2014 produced variability in some of the sub-regions, but AEMO considers the results indicate the methodology to be in general reasonably stable.

The results identified some generation sub-regions that were not able to be given TA allocation at levels they are likely to consider they currently have. In particular, generators in the vicinity of Snowy in NSW were limited by a network constraint where the NSW region has not been subject to frequent congestion within the region in recent years. This has not been fully investigated but is likely to be a result of attempting to dispatch all NSW generation to maximum output, non-extreme non-RRN NSW loads, and recent upgrades of the NSW transmission network that may change current understandings of typical NSW limits.

The regional results indicated that the residual access for interconnectors would be zero in many cases, with imports to Victoria from NSW and South Australia most likely to be able to support access from interconnectors.

The scenario results generally resulted in equivalent or lower TA allocation compared to the base case. Some sub-regions experienced large differences in TA allocation in different scenarios, particularly the NSW Snowy sub-region. In addition. Victoria had higher TA allocation in the winter and high wind summer scenarios.

Options for Further Analysis

AEMO and the AEMC have discussed a number of options for further analysis. These are discussed in section 4.3.

AEMO is willing to develop the options further with AEMC staff if requested.

APPENDIX 1 – SCENARIOS

Table A-1 —Summary of Scenario TA Allocations

Scenario	Name	Date	DI ending	NEM Demand
1	Base Scenario (summer peak)	15 January 2014	15:00	32,623
2	Steeper Taper	15 January 2014	15:00	32,623
3	Off-peak	12 January 2014	04:05	16,567
4	High Wind, High Temperature	20 December 2013	11:30	26,912
5	Winter Peak	6 June 2013	19:30	25,644
6	Mothballed Generation	15 January 2014	15:00	32,623
7	Flowgate Support	15 January 2014	15:00	32,623

APPENDIX 2 – REGION DEMAND

The methodology described in section 3 requires AEMO to model additional demand at each RRN to obtain a maximum simultaneously feasible supply in each region. Table A-3 shows the additional demand modelled in the base scenario. Table A-4 shows the change in demand of each scenario compared to the final modelled demand in the base scenario.

Table A-2 —Base Scenario Demand and Added Demand

Region	Demand	Added	Final
NSW	11710	3917	15627
Queensland	6793	4969	11762
South Australia	2907	1630	4637
Tasmania	1232	1805	3037
Victoria	9980	1797	11777

Table A-3 —Scenario Demand Reductions Compared with Base Scenario

Region	Taper	Off-peak	High Wind	Winter	Mothballed	Flowgate
NSW	215	1307	538	128	1	0
Queensland	8	112	69	269	0	141
South Australia	2	140	296	262	-35	0
Victoria	16	154	-231	-231	0	0

MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
$/MWh	Dollars per megawatt hour
MW	Megawatt
MWH	Megawatt hour

Abbreviations

Abbreviation	Expanded name
DI	Dispatch interval
DUID	Dispatchable unit identifier
FCAS	Frequency control ancillary service
LHS	Constraint left-hand side.
NEMDE	National Electricity Market Dispatch Engine
OFA	Optional Firm Access
POE	Probability of exceedenc
RRN	Regional reference node
TA	Transitional access
TNSP	Transmission Network Service Provider

GLOSSARY

Term	Definition
Flow gate	A boundary between two sub-regions where the flow through the flow gate is the sum of the flow on all transmission lines crossing the flow gate.
Network constraint equation	A mathematical description of a transmission network technical capability in a format suitable for consideration in the central dispatch process. It comprises a left-hand side comprising dependent variables (scheduled generators, loads and network services), a relationship (usually less than or equal to) and a right-hand side comprising independent variables (such as measures of demand, generation and line flow, calculations and constants).
Optional Firm Access	An integrated package of market arrangements developed by the AEMC as part of its Transmission Frameworks Review. Refer the technical report on optional firm access.[7]
Right-hand side	See network constraint equation.
System normal	A network configuration that could be expected under normal conditions without outages for maintenance or due to plant failures.

[7] AEMC. *Technical Report: Optional Firm Access*. 11 April 2013. **http://www.aemc.gov.au/getattachment/7e308487-d5d8-4170-a277-3d69c3069d12/Transmission-Frameworks-Review-Technical-Report-Op.aspx**