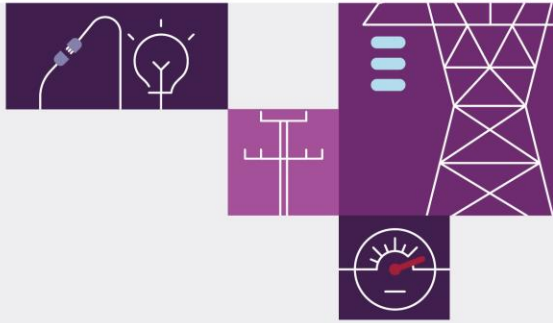# Constraint Implementation Guidelines

~~February~~ April 2023

A report for the National Electricity Market on how constraint equations are implemented from limit advice.

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Important notice

Purpose

This publication has been prepared by AEMO to provide information about implementing constraint equations, as at the date of publication.

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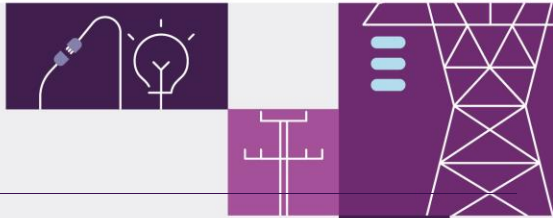
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Version control

Version	Release date	Changes
3	20 April~~9 February~~ 2023	Complete review with updated examples. Updated to latest AEMO template. Added examples for future 1 second FCAS
2	June 2015	Corrected URLs for AEMO website, added FCAS sections from FCAS guide (load, network, separation events and regulation), correction to STEP operator example, updated CVPs, added section on RRN selection, moved Tas FCAS calculation method to new limit advice, updated thermal overload example for new NSW generators. Converted to new AEMO template.
1	14 September 2011	Initial version

Contents

Tables

Figures

1 Introduction

This document provides participants, prospective participants, and parties interested in the National Electricity Market (NEM), information on the way AEMO models network congestion in the National Electricity Market Dispatch Engine (NEMDE), using constraint equations.

In each section, you will find worked examples (based on real power system conditions) that detail how constraint equations are implemented from the limit advice provided to AEMO.

This is an intermediate to advanced level document and readers should be familiar with constraint equations in general. AEMO recommends:

- Attending the 'Network and FCAS constraints in the NEM course[1].
- Reading the 'Constraint Formulation Guidelines' (CFG) on how constraint equations are formulated[2].

1.1 Other AEMO Publications

This document is a companion to the 'Constraint Formulation Guidelines' and 'Constraint Naming Guidelines[3].

Together, the three documents ~~provides~~provide readers information on how constraint equations are formulated, labelled and implemented in AEMO's systems.

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[1] Network and FCAS constraints in the NEM: https://www.aemo.com.au/learn/industry-courses/network-and-fcas-constraints-in-the-nem

[2] Constraint Formulation Guidelines – available on the Congestion Information Resource: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource

[3] Constraint Naming Guidelines – available on the Congestion Information Resource: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource

2   Constraint Formulation

Constraint equations are only constructed for one ~~particular~~ limit and are not built for combinations of limit types. Constraint equations have 4 major components: a ~~left hand~~left-hand side (LHS), a mathematical operator, a ~~right hand~~right-hand side (RHS) and description data.

The general form of the constraint equations ~~are~~is covered in detail in section ~~5.1~~4.1 of the Constraint Formulation Guidelines (CFG).

2.1   Structure

For a given network condition, such as system normal or an outage, one or more constraint sets may be required. Each constraint set may contain one or more constraint equations and the constraint equation is made up of a number of components (detailed in Figure 1~~Figure 1~~ below).

Figure 1   Structure of constraints
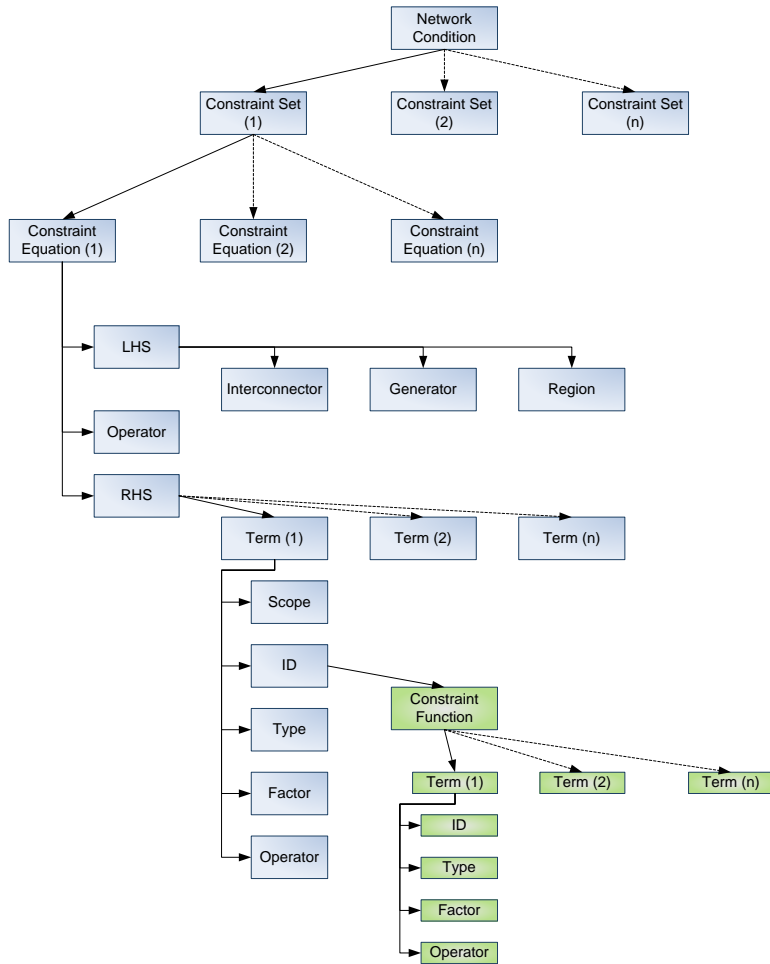
2.2   Left hand side

The ~~left hand~~left-hand side (LHS) is a linear combination of elements that can be controlled by NEMDE, such as flows on interconnectors, dispatch of scheduled generators, semi-scheduled generators and scheduled loads, and provision of regional frequency control ancillary services (FCAS).

Dispatch of scheduled generators, semi-scheduled generators and scheduled loads are represented on the LHS by their connection point ID. For example, Bayswater unit 1 is NBAY1 and Tarong unit 1 is QTRN1. Both generators and loads represent a positive value.

Interconnectors are represented by an interconnector ID on the LHS. The direction of power flow is indicated by positive and negative values. Table 1 below summarises the IDs used for interconnectors and positive direction of flow.

Table 1   Interconnector IDs and direction

ID	Name	Positive Direction
N-Q-MNSP1	Terranora	NSW to Qld
NSW1-QLD1	Qld to NSW Interconnector (QNI)	NSW to Qld
VIC1-NSW1	Victoria to NSW	Victoria to NSW
V-S-MNSP1	Murraylink	Victoria to South Australia
V-SA	Vic to SA	Victoria to South Australia
T-V-MNSP1	Basslink	Tasmania to Victoria

FCAS provision is enabled by NEMDE on a regional basis (as the summation of all the plant providing the FCAS service). In constraint equations the regional FCAS is represented on the LHS by the region ID. For example, NSW region FCAS uses the ID of NSW1. FCAS provision represents a positive value.

The regional FCAS and generator LHS terms also include a bid type to indicate which market the term applies for. Regional FCAS terms only apply to the eight FCAS markets.

2.3   Operators

Constraint equations can use one of three operators (≥, ≤ or =). Network constraint equations usually use ≤ and FCAS use ≥. In cases where a generator is disconnected from their parent region their FCAS is set to zero and these constraint equations use the ≤ operator (see section 8.65.6 in the CFG).

The = operator is avoided.

2.4   Right hand side

The right handright-hand side (RHS) of a constraint equation consists of one or more terms that can include many different types of data (see 2.4.1) as well as complex calculations. A different RHS can be specified for each of the different timeframes: dispatch, 30-minute pre-dispatch, ST PASA and MT PASA. Five-minute pre-dispatch does not have specific RHS terms and uses either the dispatch or pre-dispatch RHS.

A term on the RHS consists of the ID, the type, the factor, an optional operator (full details of these in Appendix A), a numerical term ID, a numerical group ID, and a default value.

2.4.1   RHS types

Each RHS SPD ID has a single character that defines how the data for that point is retrieved and manipulated. Some IDs are for data and others for mathematical operations. IDs can use different values in dispatch, pre-dispatch and PASA.

Table 2   Right hand side types

Type	Name	Description
C	Constant	A constant value that can be positive or negative.
A	Analog	An analog value from SCADA. PASA does not allow A types to be used on the RHS.
S	Status	A status value from SCADA. Similar to an analog value but only has values of 1 or 0. Used for the status of plants such as a capacitor bank in or out of service. PASA does not allow S types to be used on the RHS.
R	Region demand	The regional demand forecast. The ID used is the region ID (such as NSW1 or TAS1). In dispatch, and the first interval of pre-dispatch, the current SCADA value for the region demand is used. For the remainder of pre-dispatch and PASA, the forecast value is used.
I	Interconnector	The interconnector flow: the sign convention and the IDs used are the same as detailed in 2.2. In dispatch and the first interval of pre-dispatch, the current SCADA value is used. The remainder of pre-dispatch uses the target value from the previous trading interval.
T	Trader	Scheduled Generators, Semi-Scheduled Generators and scheduled loads: the ID is the generator DUID followed by the connection point ID. (For example, Bayswater 1 is BW01.NBAY1 and Tarong 1 is TARONG#1.QTRN1). In dispatch and the first interval of pre-dispatch, the current SCADA value is used. The remainder of pre-dispatch uses the target value from the previous trading interval.
E	Entered value	Time varying input data that is used for a wide variety of data such as transmission element ratings, sub-regional forecasts (either areas or zones) and non-scheduled wind farm forecasts. The ID used for equipment ratings is defined in section 9.2 of the constraint naming guidelines. (For example, TRAT15_PMSH). Non-scheduled wind farms use an ID of the form WIND_ RegionID _XXX (such as WIND_N_CAP). Sub-regional forecasts use an ID RegionID_RLOAD_XXX (such as QRLOAD_CEN). Zone demand forecasts use an ID of the form RegionID_NAME (such as S_SOUTHEAST)
M	Max available bid (from)	The offered availability of an MNSP interconnector flow at its defined "from" region end. The ID used is the interconnector ID (Table 1). Currently only used for Basslink – this is used for the Victoria to Tasmania direction availability.
N	Max available bid (to)	The offered availability of an MNSP interconnector flow at its defined "to" region end. The ID used is the interconnector ID (Table 1). Currently only used for Basslink – this is used for the Tasmania to Victoria direction availability.
W	Switch run status	NEMDE will perform two runs: one where the value for this SPD ID is the SCADA status value (either 1 or 0), and the other of 0. The run with the lowest objective function will be published.
G	Group	Used for collating several terms together, i.e., mathematically the same as using brackets. See A.3 for how groups are calculated.
X	Function	This references a set of RHS terms. The X type is used where a common calculation (such as a complex transient stability calculation) is required across a number of constraint equations. The ID for this matches the constraint function ID. See A.4 on the calculation of constraint functions.
B	Branch	Branch types implement if/then/else type logic (see A.9.3). This type is rarely used now with the more flexible operators POP and EXLEZ used instead.
U	Stack	Stack terms are used for performing operations on one or more elements on the stack (see A.8).

The ID field is ignored by NEMDE for C, G, B and U types. Constraint builders normally create an ID that reflects the purpose of the terms or the calculation (such as "Scale"). Spaces are not used in the IDs and are generally replaced with dashes or underscores (such as "Operating_Margin").

The full list of A, S, I, T and R terms is located in the EMSMASTER table in the MMS Data Model.

2.5   Constraint violation penalty factors

Each constraint equation has a constraint violation penalty (CVP) factor applied to give a priority order for NEMDE. In this way thermal overload constraint equations (CVP of 30) are violated in preference to transient

stability (CVP of 35) or no contingency (CVP of 360) constraint equations – see CFG section ~~9.5.1~~2.10.1 and Table 3.

Energy constraint equations use a CVP of 360 for satisfactory limits (those for a no contingencies such as the

F2 transformer overload), 35 for secure limits for stability constraint equations, and 30 for secure limits for thermal overloads (for one or more contingencies, such as the example described in section 3).

FCAS constraint equations use one of four values depending on the services included on the LHS. Where both

5-minute and regulation services are included, the higher CVP value is used.

Table 3   **Constraint violation penalty factors used in constraint equations**

Description	CVP
Satisfactory	360
Secure	35
Secure – Thermal	30
Regulation Raise/Lower FCAS	10
1 second Raise/Lower FCAS	9
6 second Raise/Lower FCAS	8
60 second Raise/Lower FCAS	6
~~5 minute~~5-minute Raise/Lower FCAS	4
Network Support	30
Interconnector / Unit Zero / Non-Conformance	1160

2.6   Swamping

There is no method provided by NEMDE to automatically switch on or off the individual LHS of constraint equations, based on a calculation. There are a number of cases (such as managing the Basslink FCAS constraint equations) where different LHS terms or factors are required.

To manage these cases, the RHS of the constraint equation is set to a value that can always be satisfied. For <= constraint equations 10000 is added to the RHS, for >= constraint equations 10000 is subtracted from the RHS. This technique is known as swamping.

Normally a pair of constraint equations is constructed: one is normally un-swamped and the other is normally swamped. Section 4.1.5 includes an example of where swamping is used on a pair of FCAS constraint equations.

3 Thermal overload

Constraint equations for avoiding thermal overloads on transmission lines or transformers are normally built as a feedback type (see section 7.24.2 in the CFG). The general form of a constraint equation's Dispatch RHS is:

a x Generator 1

– b x Generator 2

+ c x Interconnector ≤

[Limit

– Flow across line(s)

] x Scaling

+ a x Generator 1 (current value)

– b x Generator 2 (current value)

+ c x Interconnector (current value)

Normally, AEMO calculates the contribution factors using power flow analysis software (such as PSSE) and uses the rating supplied by the transmission network service provider (TNSP) or distribution network service provider (DNSP). Rating selection is detailed in Appendix 0A2.

The following worked example in Figure 2 details how AEMO calculates the factors, and which of those appear on the LHS and RHS, as well as how the dispatch and pre-dispatch RHS factors are formulated. This example is for a constraint equation in NSW for avoiding overloading the Marulan to Dapto (8) 330 kV line on the trip of the Marulan to Avon (16) 330 kV under system normal conditions. This constraint equation is implemented in AEMO's systems as the constraint equation ID N>>N-NIL_8_1628.

Figure 2   Single line diagram of southern NSW electricity network
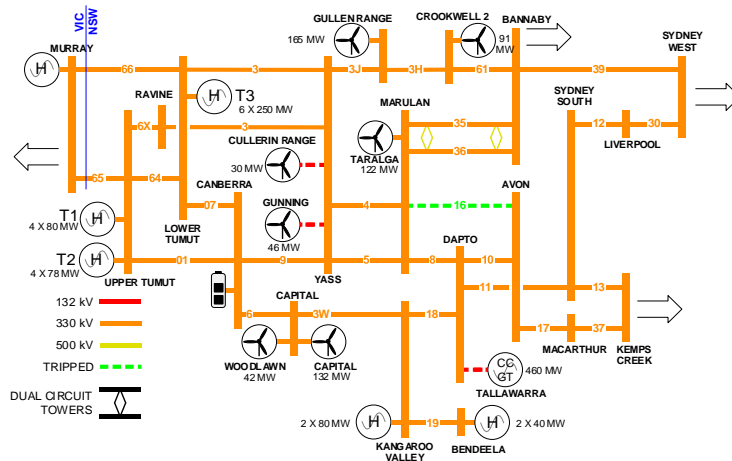
3.1 Determining factors

To calculate the generator or load factors (in the example above), AEMO first switches the contingent transmission element out of service in the power flow software and then runs the power flow on the new configuration. This is then used to calculate the factor for generators and interconnectors.

The factor is the contribution, relative to a single bus (known as the swing bus), to the monitored line flow that the generator/load makes for a 1 MW increase in the generator output. In the NEM, the swing bus is set to the regional reference node (RRN) of the region where the limitation is located. In this case, the Marulan to Dapto line is located in NSW so the swing bus is set to Sydney West.

3.1.1 Parent Region Generators

The factors are first determined for the generators in the same region as the swing bus. The factors for all the relevant NSW plant (this includes several large non-scheduled wind farms) are listed in Table 4 from smallest to largest.

Table 4   Raw generator factors for thermal overload example

Generator	Raw factor
Taralga	0.2772
Gullen Range	0.2172
Cullerin Range & Gunning	0.1852
Blowering	0.1786
Uranquinty	0.1722
Hume NSW	0.1708
Lower Tumut	0.1693
Upper Tumut	0.1687
Guthega	0.1465
Boco Rock	0.1465
Nyngan Solar	0.0827
Mt Piper	0.0756
Bayswater 3 & 4	0.0626
Capital & Woodlawn	0.0477
Bayswater 1 & 2	0.0399
Liddell & Hunter GT	0.0377
Eraring 1 & 2	–0.0095
Vales Pt	–0.0092
Colongra	–0.0094
Eraring 3 & 4	–0.0345
Shoalhaven	–0.1662
Tallawarra	–0.2362
Taralga	0.2737
Collector	0.2246
Crookwell 2	0.2183

Generator	Raw factor
Gullen Range	0.2135
Cullerin Range & Gunning	0.1815
Blowering	0.1750
Bango 1	0.1744
Bango 2	0.1743
Bomen, Junee, Sebastopol, Wagga Nth, West Wyalong and Wyalong	0.1693
Uranquinty	0.1686
Avonlie	0.1682
Finley and Griffith	0.1677
Coleambally, Darlington Point, Hillston and Riverina BESS	0.1675
Corowa and Hume NSW	0.1669
Limondale 1 & 2 and Sunraysia	0.1667
Broken Hill and Silverton	0.1664
Guthega	0.1653
Lower Tumut	0.1653
Upper Tumut	0.1649
Boco Rock	0.1428
Queanbeyan BESS	0.1425
Capital BESS	0.1424
Jemalong	0.1191
Goonumbla and Parkes	0.1063
Manildra	0.0895
Suntop	0.0850
Molong	0.0841
Nyngan, Nevertire & Wellington	0.0823
Bodangora	0.0814
Beryl	0.0798
Crudine Ridge	0.0758
Mt Piper	0.0742
Bayswater 3 & 4	0.0611
Capital & Woodlawn	0.0434
Bayswater 1 & 2	0.0386
Gunnedah	0.0345
New England Solar 1 & 2 and Moree	0.0337
Sapphire	0.0336
White Rock	0.0329
Metz	0.0328
Vales Pt	-0.0108
Colongra	-0.0109
Eraring 1 & 2	-0.0113

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Generator	Raw factor
Eraring 3 & 4	-0.0378
Shoalhaven	-0.1704
Tallawarra	-0.2404

3.1.2 Interconnectors

Interconnectors are used to represent the contribution of the adjacent region generators. The factor for an AC interconnector is the factor at the adjacent region's RRN, using the same swing bus as for the parent region generators. DC interconnector factors are calculated by placing a dummy generator at the parent region end of the link, and using the factor of the dummy generator relative to the swing bus.

In both cases, the sign used on the interconnector factor is adjusted to represent the NEM convention for interconnector direction (see 2.2). Table 5 details the factors for the three interconnectors between NSW and Qld and Victorian regions.

Table 5   Raw interconnector factors for thermal overload example

Generator	Raw factor
NSW1-QLD1	−0.03195
N-Q-MNSP1	−0.03363
VIC1-NSW1	0.165898

3.1.3 Remote region generators / interconnectors

Normally, generators in the region adjacent to the swing bus region have the same factor as the interconnector to that region. Where generators or interconnectors are located electrically close to the regional boundary, these can have a different contribution than the region as a whole. As the adjacent region contribution is modelled by the interconnector factor, the extra contribution is modelled by taking the raw factor for the remote generator/interconnector and subtracting the interconnector factor.

From Table 6 both Murray and Murraylink have different factors than the VIC1-NSW1 interconnector (as they are close to the NSW/Victoria boundary). The corrected factors remain small. For Loy Yang and Millmerran they have the same factors as the VIC1-NSW1 and NSW1-QLD1 interconnectors respectively – their corrected factors are zero.

Table 6   Remote region generators and interconnector factors

Generator / interconnector	Raw factor	Relative factor
Murray	−0.166492	-0.000516
V-S-MNSP1	−0.166393	−0.0005
Loy Yang	−0.165898	0
Millmerran	−0.03365	0

In some cases the factors on these can be large enough to appear on the LHS of constraint equations. Both Murray and Murraylink appear on the LHS of the constraint equations N>>V-NIL_HD and N>>V-NIL_HC (for overloads of the Murray to Upper Tumut and Murray to Lower Tumut 330 kV lines).

3.1.4   Normalising / scaling

The factors on the LHS of constraint equations are normalised (see section 7.22.6.1 in the CFG) so that the absolute value of the largest factor is 1. Table 7 shows that the largest absolute factor is on Taralga (0.273772). To make this 1, it needs to be multiplied by 3.65408 (1 / 0.273772).

Table 7   Scaled factors

Generator / interconnector	Raw factor	Scaled factor
Taralga	0.2772	1
Gullen Range	0.2172	0.7835
Cullerin Range & Gunning	0.1852	0.6681
Blowering	0.1786	0.6443
Uranquinty	0.1722	0.6212
Hume NSW	0.1708	0.6162
Lower Tumut	0.1693	0.6108
Upper Tumut	0.1687	0.6086
Guthega	0.1465	0.5285
Boco Rock	0.1465	0.5285
Nyngan Solar	0.0827	0.2983
Mt Piper	0.0756	0.2727
Bayswater 3 & 4	0.0626	0.2258
Capital & Woodlawn	0.0477	0.1721
Bayswater 1 & 2	0.0399	0.1439
Liddell & Hunter GT	0.0377	0.136
Eraring 1 & 2	−0.0095	−0.0343
Vales Pt	−0.0092	−0.0332
Colongra	−0.0094	−0.0339
Eraring 3 & 4	−0.0345	−0.1245
Shoalhaven	−0.1662	−0.5996
Tallawarra	−0.2362	−0.8521
NSW1-QLD1	−0.035	−0.1263
N-Q-MNSP1	−0.0333	−0.1201
VIC1-NSW1	0.11698	0.6126
Taralga	0.2737	1.0000
Collector	0.2246	0.8207
Crookwell 2	0.2183	0.7977
Gullen Range	0.2135	0.7800
Cullerin Range & Gunning	0.1815	0.6634
Blowering	0.1750	0.6396
Bango 1	0.1744	0.6372
Bango 2	0.1743	0.6369
Bomen, Junee, Sebastopol, Wagga Nth, West Wyalong and Wyalong	0.1693	0.6187
Uranquinty	0.1686	0.6162

Generator / interconnector	Raw factor	Scaled factor
Avonlie	0.1682	0.6145
Finley and Griffith	0.1677	0.6127
Coleambally, Darlington Point, Hillston and Riverina BESS	0.1675	0.6119
Corowa and Hume NSW	0.1669	0.6100
Limondale 1 & 2 and Sunraysia	0.1667	0.6092
Broken Hill and Silverton	0.1664	0.6080
VIC1-NSW1	0.1658	0.6060
Guthega	0.1653	0.6041
Lower Tumut	0.1653	0.6040
Upper Tumut	0.1649	0.6026
Boco Rock	0.1428	0.5218
Queanbeyan BESS	0.1425	0.5206
Capital BESS	0.1424	0.5204
Jemalong	0.1191	0.4350
Goonumbla and Parkes	0.1063	0.3883
Manildra	0.0895	0.3270
Suntop	0.0850	0.3104
Molong	0.0841	0.3075
Nyngan, Nevertire & Wellington	0.0823	0.3007
Bodangora	0.0814	0.2975
Beryl	0.0798	0.2914
Crudine Ridge	0.0758	0.2770
Mt Piper	0.0742	0.2709
Bayswater 3 & 4	0.0611	0.2232
Capital & Woodlawn	0.0434	0.1587
Bayswater 1 & 2	0.0386	0.1409
Gunnedah	0.0345	0.1262
New England Solar 1 & 2 and Moree	0.0337	0.1233
Sapphire	0.0336	0.1227
NSW1-QLD1	-0.0336	-0.1226
White Rock	0.0329	0.1201
Metz	0.0328	0.1198
N-Q-MNSP1	-0.0319	-0.1166
Vales Pt	-0.0108	-0.0393
Colongra	-0.0109	-0.0398
Eraring 1 & 2	-0.0113	-0.0412
Eraring 3 & 4	-0.0378	-0.1383
Shoalhaven	-0.1704	-0.6228
Tallawarra	-0.2404	-0.8783

Table 8   Scaled factors for remote region generators and interconnector factors

Generator / Interconnector	Raw factor	Relative factor	Scaled factor
Murray	–0.166~~492~~	-0.000~~51~~6	-0.001~~9~~22
V-S-MNSP1	–0.166~~39~~3	–0.0005	–0.0018

3.2 Left hand side selection

The absolute value of the factors on the ~~left hand~~left-hand side (LHS) must be greater than or equal to 0.07 (see section ~~5.5.1~~2.6.1 in the CFG). Where the factors are lower than 0.07, these terms are moved onto the ~~right hand~~right-hand side (RHS) by subtracting the term from both sides (hence the term appears with the opposite sign).

Table 9 shows the terms with factors that are too small to appear on the LHS.

Table 9   Small factors

Generator / interconnector	Scaled factor
~~Colongra~~Vales Pt	–0.039~~33~~9
~~Vales Pt~~Colongra	–0.039~~83~~2
Eraring 1 & 2	–0.0~~4123~~43
Murray	–0.001~~8~~22
V-S-MNSP1	–0.0018

3.2.1 Treatment of non-scheduled wind farms

Non-scheduled generators cannot appear on the LHS. Where the non-scheduled generator is a wind farm, this is also subtracted from the RHS and then multiplied by –1. The reason is that, unlike scheduled generators which have a positive input value on the LHS and RHS, non-scheduled wind farms have a negative input value from the Australian wind energy wind forecasting system (AWEFS).

The Cullerin and Capital wind farms are non-scheduled, so these are moved to the pre-dispatch RHS.

Other types of non-scheduled generators, which do not have a forecast value in pre-dispatch, are generally not included in the constraint equation.

3.2.2 Scheduled loads and Batteries

Where a scheduled load is in the same location as a generator (such as Shoalhaven, Lower Tumut and Wivenhoe), it is included on LHS or RHS with the generator's factor multiplied by –1.

3.2.3 LHS

The LHS for this constraint equation is:

1 x Taralga wind farm

+ 0.8207 x Collector wind farm

+ 0.7977 x Crookwell 2 wind farm

+ 0.78~~00~~35 x Gullen Range 1 & 2 wind farms and solar farm~~Range wind farm~~

+ 0.66~~34~~81 x Gunning wind farm

+ 0.6396443 x Blowering

+ 0.6372 x Bango 1 wind farm

+ 0.6369 x Bango 2 wind farm

+ 0.6187 x Bomen solar farm

+ 0.6187 x Junee solar farm

+ 0.6187 x Sebastopol solar farm

+ 0.6187 x Wagga Nth solar farm

+ 0.6187 x West Wyalong solar farm

+ 0.6187 x Wyalong solar farm

+ 0.6162212 x Uranquinty

+ 0.6100 x Corowa solar farm

+ 0.610062 x Hume NSW

+ 0.6092 x Limondale 1 & 2 solar farms

+ 0.6092 x Sunraysia solar farm

+ 0.6080 x Broken Hill solar farm

+ 0.6080 x Silverton solar farm

+ 0.6060126 x VIC1-NSW1

+ 0.60415285 x Guthega

+ 0.6040108 x Lower Tumut

− 0.6040108 x Lower Tumut pumps

+ 0.602686 x Upper Tumut

+ 0.5285 x Guthega

+ 0.521885 x Boco Rock wind farm

+ 0.5206 x Capital battery (generator)

- 0.5206 x Capital battery (load)

+ 0.5206 x Queanbeyan battery (generator)

- 0.5206 x Queanbeyan battery (load)

+ 0.4350 x Jemalong solar farm

+ 0.3883 x Goonumbla solar farm

+ 0.3883 x Parkes solar farm

+ 0.3270 x Manildra solar farm

+ 0.3104 x Suntop solar farm

+ 0.3075 x Molong solar farm

+ 0.3007 x Nevertire solar farm

+ 0.3007~~2983~~ x Nyngan solar farm

+ 0.3007 x Wellington solar farm

+ 0.2975 x Bodangora solar farm

+ 0.2914 x Beryl solar farm

+ 0.2770 x Crudine Ridge wind farm

+ 0.270~~927~~ x Mt Piper 1 & 2

+ 0.22~~32~~258 x Bayswater 3 & 4

+ 0.15~~87~~721 x Woodlawn wind farm

+ 0.14~~0~~939 x Bayswater 1 & 2

+ 0.1262 x Gunnedah solar farm

+ 0.1233 x New England 1 & 2 solar farm

+ 0.1233 x Moree solar farm

+ 0.1233 x Sapphire wind farm

+ 0.1201 x White Rock wind and solar farms

+ 0.1198 x Metz solar farm

~~+ 0.136 x Liddell 1, 2, 3 & 4~~

~~+ 0.136 x Hunter GTs~~

−0.1~~166~~201 x N-Q-MNSP1

~~– 0.1245 x Eraring 3 & 4~~

−0.12~~26~~663 x NSW1-QLD1

~~– 0.1383~~245 x Eraring 3 & 4

– 0.~~6228~~5996 x Shoalhaven

+ 0.~~6228~~5996 x Shoalhaven pumps

– 0.8~~783~~521 x Tallawarra

3.3   Dispatch RHS

3.3.1   Monitored element

The rating used on the RHS is chosen based on the criteria in Appendix 0~~A2~~ (selection of ratings). As the lines are in NSW the rating used is the contingency rating. Line ratings can be different at either end of the line. Therefore, the rating chosen is the sending end of the line: the Marulan end of the Marulan to Dapto (8) 330 kV line.

Similarly, the flow on the line is also chosen at the sending end of the line and this is subtracted from the rating.

3.3.2 Tripped element

The percentage of the flow (known as the redistribution factor (RDF)) on the tripped element that is transferred to the monitored element, is calculated by comparing the power system before and after the trip:

$$\frac{\textit{Monitored element flow (after)} - \textit{Monitored element flow (before)}}{\textit{Tripped element flow (before)}}$$

3.3.3 Operating margin

Each constraint equation includes an operating margin. For 330 kV lines in NSW the operating margin is 30.

3.3.4 Scaling term and current values of LHS terms

The scaling value calculated in 3.1.4 is included as a separate term on the RHS after the headroom calculation and the operating margin.

Following the scaling value, the current value of the LHS terms appears, and their factors are transferred directly across with no sign change. The normal practice is for these to appear after the scaling term, to allow for easier checking of the LHS and RHS factors.

3.3.5 Algebraic and implemented RHS

The dispatch RHS for this constraint equation is:

[Rating on Marulan to Dapto (8) 330 kV line

– MVA~~W~~ flow on Marulan to Dapto (8) 330 kV line

– 0.4979~~893~~ x MVA~~W~~ flow on Marulan to Avon (16) 330 kV line

– 30 (Operating Margin)

] x 3.65~~408~~

1 x Taralga wind farm

+ 0.8207 x Collector wind farm

+ 0.7977 x Crookwell 2 wind farm

+ 0.7800 x Gullen Range 1 & 2 wind farms and solar farm

+ 0.6634 x Gunning wind farm

+ 0.6396 x Blowering

+ 0.6372 x Bango 1 wind farm

+ 0.6369 x Bango 2 wind farm

+ 0.6187 x Bomen solar farm

+ 0.6187 x Junee solar farm

+ 0.6187 x Sebastopol solar farm

+ 0.6187 x Wagga Nth solar farm

+ 0.6187 x West Wyalong solar farm

+ 0.6187 x Wyalong solar farm

+ 0.6162 x Uranquinty

+ 0.6100 x Corowa solar farm

+ 0.6100 x Hume NSW

+ 0.6092 x Limondale 1 & 2 solar farms

+ 0.6092 x Sunraysia solar farm

+ 0.6080 x Broken Hill solar farm

+ 0.6080 x Silverton solar farm

+ 0.6060 x VIC1-NSW1

+ 0.6041 x Guthega

+ 0.6040 x Lower Tumut

– 0.6040 x Lower Tumut pumps

+ 0.6026 x Upper Tumut

+ 0.5218 x Boco Rock wind farm

+ 0.5206 x Capital battery (generator)

- 0.5206 x Capital battery (load)

+ 0.5206 x Queanbeyan battery (generator)

- 0.5206 x Queanbeyan battery (load)

+ 0.4350 x Jemalong solar farm

+ 0.3883 x Goonumbla solar farm

+ 0.3883 x Parkes solar farm

+ 0.3270 x Manildra solar farm

+ 0.3104 x Suntop solar farm

+ 0.3075 x Molong solar farm

+ 0.3007 x Nevertire solar farm

+ 0.3007 x Nyngan solar farm

+ 0.3007 x Wellington solar farm

+ 0.2975 x Bodangora solar farm

+ 0.2914 x Beryl solar farm

+ 0.2770 x Crudine Ridge wind farm

+ 0.2709 x Mt Piper 1 & 2

+ 0.2232 x Bayswater 3 & 4

+ 0.1587 x Woodlawn wind farm

+ 0.1409 x Bayswater 1 & 2

+ 0.1262 x Gunnedah solar farm

+ 0.1233 x New England 1 & 2 solar farm

+ 0.1233 x Moree solar farm

+ 0.1233 x Sapphire wind farm

+ 0.1201 x White Rock wind and solar farms

+ 0.1198 x Metz solar farm–0.1166 x N-Q-MNSP1

–0.1226 x NSW1-QLD1

– 0.1383 x Eraring 3 & 4

– 0.6228 x Shoalhaven

+ 0.6228 x Shoalhaven pumps

– 0.8783 x Tallawarra

+ 0.7835 x Gullen Range wind farm

+ 0.6681 x Gunning wind farm

+ 0.6443 x Blowering

+ 0.6212 x Uranquinty

+ 0.6162 x Hume NSW

+ 0.6126 x VIC1-NSW1

+ 0.6108 x Lower Tumut

– 0.6108 x Lower Tumut pumps

+ 0.6086 x Upper Tumut

+ 0.5285 x Guthega

+ 0.5285 x Boco Rock wind farm

+ 0.2983 x Nyngan solar farm

+ 0.2727 x Mt Piper 1 & 2

+ 0.22258 x Bayswater 3 & 4

+ 0.1721 x Woodlawn wind farm

+ 0.1439 x Bayswater 1 & 2

+ 0.136 x Liddell 1, 2, 3 & 4

+ 0.136 x Hunter GTs

– 0.1201 x N-Q-MNSP1

– 0.1245 x Eraring 3 & 4

– 0.1263 x NSW1-QLD1

– 0.5996 x Shoalhaven

Table 10 shows how the dispatch RHS would be implemented in AEMO's market systems.

Table 10   Dispatch RHS

Term ID	Group ID	SPD ID	SPD type	Factor	Operator
1		NRATSE_MNDT8	E	1	
2		MVAW_MN_8	A	−1	
3		MVAW_MN_16	A	-0.4969 0.4893	
4		Operating_Margin	C	−30	
5		Scale	U	3.654 3.608	
6		N-Q-MNSP1 TARALGA1.NMR22T	I T	-0.1166 1	
7		NSW1-QLD1 GULLRWF1.NGUR1G	I T	-0.1226 0.7835	
8		VIC1-NSW1 GUNNING1.NYS12A	I T	0.6060 0.6681	
9		AVLSF1.NNRN1A BLOWERNG.NBLW8	T T	0.6145 0.6443	
10		BANGOWF1.NBA21 BURANQ11.NURQ1U	T T	0.6372 0.6212	
11		BANGOWF2.NBB21 BURANQ12.NURQ2U	T T	0.6369 0.6212	
12		BERYLSF1.NBES1 BURANQ13.NURQ3U	T T	0.2914 0.6212	
13		BLOWERNG.NBLW8 URANQ14.NURQ4U	T T	0.6396 0.6212	
14		BOCORWF1.NCMA3B HUMENSW.NHUM	T T	0.5218 0.6162	
15		BODWF1.NBOD1B VIC1-NSW1	T I	0.2975 0.6126	
16		BOMENSF1.NWGS1B TUMUT3.NLTS8	T T	0.6188 0.6108	
17		BROKENH1.NBK11B UPPTUMUT.NUTS8	T T	0.6080 0.6086	
18		BW01.NBAY1 SHPUMP.NSHP1	T T	0.1409 0.5996	
19		BW02.NBAY2 BOCORWF1.NCMA3B	T T	0.1409 0.5285	
20		BW03.NBAY3 GUTHEGA.NGUT8	T T	0.2232 0.5285	
21		BW04.NBAY4 NYNGAN1.NWL8	T T	0.2232 0.2983	
22		CAPBES1G.NQBC1C MP1.NMTP1	T T	0.5204 0.2727	
23		CAPBES1L.NQBC2C MP2.NMTP2	T T	-0.5204 0.2727	
24		COLEASF1.NCLS1C BW03.NBAY3	T T	0.6120 0.2258	
25		COLWF01.NCLW1C BW04.NBAY4	T T	0.8207 0.2258	
26		CROOKWF2.NCKW1C WOODLWN1.NCWF2W	T T	0.7977 0.1721	
27		CRURWF1.NCDS1C BW01.NBAY1	T T	0.2770 0.1439	
28		CRWASF1.NAL11C BW02.NBAY2	T T	0.6110 0.1439	
29		DARLSF1.NDNS1D HVGTS.NLD31	T T	0.6119 0.136	
30		ER03.NEPS3 LD01.NLDP1	T T	0.6119 0.136	
31		ER04.NEPS4 LD02.NLDP2	T T	-0.6119 0.136	
32		FINLYSF1.NFNS1F LD03.NLDP3	T T	-0.1383 0.136	
33		GNNDHSF1.NGNE1G LD04.NLDP4	T T	-0.1383 0.136	

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Term ID	Group ID	SPD ID	SPD type	Factor	Operator
34		GOONSF1.NPG12G~N-Q-MNSP1~	T~I~	0.6127~-0.1201~	
35		GULLRSF1.NGUR2G~ER03.NEPS3~	T~T~	0.1262~-0.1245~	
36		GULLRWF1.NGUR1G~ER04.NEPS4~	T~T~	0.3883~-0.1245~	
37		GULLRWF2.NGUR3G~NSW1-QLD1~	T~I~	0.7800~-0.1263~	
38		GUNNING1.NYS12A~SHGEN.NSHL~	T~T~	0.7800~-0.5996~	
39		GUTHEGA.NGUT8~SNOWYP.NLTS3~	T~T~	0.7800~-0.6108~	
40		HILLSTN1.NDNH1H~TALWA1.NDT13T~	T~T~	0.6634~-0.8521~	
41		HUMENSW.NHUM	T	0.6041	
42		JEMALNG1.NFBS1J	T	0.6119	
43		JUNEESF1.NWGJ1J	T	0.6100	
44		LIMOSF11.NBSF1L	T	0.4350	
45		LIMOSF21.NBL21L	T	0.6187	
46		MANSLR1.NMLS1M	T	0.1330	
47		METZSF1.NMTZ1M	T	0.1330	
48		MOLNGSF1.NMOS1M	T	0.1330	
49		MOREESF1.NMR41M	T	0.6092	
50		MP1.NMTP1	T	0.6092	
51		MP2.NMTP2	T	0.3270	
52		NEVERSF1.NWLS3N	T	0.1198	
53		NEWENSF1.NURR1N	T	0.3075	
54		NEWENSF2.NURR2N	T	0.1232	
55		NYNGAN1.NWL82N	T	0.2709	
56		PARSF1.NPG11P	T	0.2709	
57		QBYNBG1.NQBB1Q	T	0.3007	
58		QBYNBL1.NQBB2Q	T	0.1233	
59		RESS1BG.NRBB1R	T	0.1233	
60		RIVNBG2.NRB21R	T	0.3007	
61		DPNTBG1.NRDP1D	T	0.3883	
62		RESS1BL.NRBB2R	T	0.5206	
63		RIVNBL2.NRB22R	T	-0.5206	
64		DPNTBL1.NRDP2D	T	0.6118	
65		SAPHWF1.NSAP1S	T	-0.6118	
66		SEBSF1.NWGJ2S	T	0.6118	
67		SHGEN.NSHL	T	-0.6118	
68		SHPUMP.NSHP1	T	0.1227	
69		SNOWYP.NLTS3	T	0.6187	
70		STWF1.NBKW1S	T	-0.6228	

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Term ID	Group ID	SPD ID	SPD type	Factor	Operator
71		SUNRSF1.NBSF2S	T	0.6228	
72		SUNTPSF1.NWLW1S	T	-0.6040	
73		TALWA1.NDT13T	T	0.6080	
74		TARALGA1.NMR22T	T	0.6092	
75		TUMUT3.NLTS8	T	0.3104	
76		UPPTUMUT.NUTS8	T	-0.8783	
77		URANQ11.NURQ1U	T	1.0000	
78		URANQ12.NURQ2U	T	0.6040	
79		URANQ13.NURQ3U	T	0.6026	
80		URANQ14.NURQ4U	T	0.6162	
81		WAGGNSF1.NWGG1W	T	0.6162	
82		WELLSF1.NWLS4W	T	0.6162	
83		WOODLWN1.NCWF2W	T	0.6162	
84		WRSF1.NWRK2W	T	0.6188	
85		WRWF1.NWRK1W	T	0.3007	
86		WSTWYSF1.NWGJ3W	T	0.1587	
87		WYASF1.NWGJ4W	T	0.1201	

3.4 Pre-dispatch RHS

The pre-dispatch RHS shares some of the same terms with the Dispatch RHS, such as the rating, operating margin and scaling term.

Flows for the tripped and monitored elements are not available in pre-dispatch, so an estimate is made based on the regional or sub-regional demand. This is calculated by scaling the region or sub-region demand by a small amount (for example, 10 MW or 100 MW). The demand factor is then calculated as:

$$\frac{\textit{Post contingent line flow (scaled case)} - \textit{Post contingent line flow (initial case)}}{\textit{Demand change}}$$

For the post-contingent flow on the Marulan to Dapto (8) 330 kV line (following the on trip of the Marulan to Avon (16) 330 kV under system normal conditions) the NSW regional demand is used, and the co-efficient has been determined to be -0.00372.

The generator and interconnectors terms are those that were not large enough to appear on the LHS of the constraint equation and any non-scheduled wind farms.

The constant term is the difference between the post contingent flow and the sum of the generator and interconnector terms multiplied by their current output in the case used. For this pre-dispatch RHS the constant is 5.05.

3.4.1 Algebraic and implemented RHS

[Rating on Marulan to Dapto (8) 330 kV line

+– 0.003432~~372~~ x North ~~NSW~~ demand

+ 0.0339 x Sydney demand

+ 0.1376 x Canberra demand

+ 0.1678 x South West NSW demand

– 0.01526 x Victorian state grid demand

– 0.00881 x Melbourne demand

– 0.08448 x Central West NSW demand

+ 88.89~~5.05~~ (Constant)

– 30 (Operating Margin)

] x 3.65~~408~~

+ 0.039~~839~~ x Vales Pt~~Colongra~~

+ 0.039~~332~~ x Colongra ~~Vales Pt~~

+ 0.04~~12343~~ x Eraring 1 & 2

+ 0.15~~87721~~ x Capital wind farm

+ 0.66~~3481~~ x Cullerin Range wind farm

+– 0.001~~822~~ x Murray

+– 0.0018 x V-S-MNSP1

11 Table 11 shows how the pre-dispatch RHS would be implemented in AEMO's market systems.

Table 11   Pre-dispatch RHS

Term ID	Group ID	SPD ID	SPD type	Factor	Operator
1		NRATSE_MNDT8	E	1	
2		N_NORTH~~NSW1~~	E~~R~~	0.03513–0.00372	
3		N_SYDNEY	E	-0.03407	
4		N_CANBERRA	E	0.1401	
5		N_SWNSW	E	0.1725	
6		V_STATEGRID	E	-0.01067	
7		V_MELBOURNE	E	-0.004019	
8		N_CENWEST	E	0.08603	
9		Constant	C	~~5.05~~88.89	
9~~3~~		Operating Margin	C	–30	
10~~4~~		Scale	U	3.65~~408~~	
11~~5~~		VP5.NVPP5~~CG1.NCLG1D~~	T	0.039~~839~~	
12~~6~~		VP6.NVPP6~~CG2.NCLG2D~~	T	0.039~~839~~	
13~~7~~		CG1.NCLG1D~~CG3.NCLG3D~~	T	0.039~~339~~	
14~~8~~		CG2.NCLG2D~~CG4.NCLG4D~~	T	0.039~~339~~	

Term ID	Group ID	SPD ID	SPD type	Factor	Operator
159		CG3.NCLG3D~~VP5.NVPP5~~	T	0.039332	
1610		CG4.NCLG4D~~VP6.NVPP6~~	T	0.039332	
1711		ER01.NEPS1	T	0.0412343	
1812		ER02.NEPS2	T	0.0412343	
1913		WIND_N_CAP	E	0.1587721	
2014		WIND_N_CLR	E	0.663481	
2115		MURRAY.NMUR8	T	−0.001822	
2216		V-S-MNSP1	I	−0.0018	

3.5   Short term PASA RHS

The short term PASA (ST PASA) can use similar terms on the RHS to those used by pre-dispatch except for analog, status and interconnector terms. In the example below, all the terms are the same between pre-dispatch and ST PASA, except for the Murraylink interconnector.

[Rating on Marulan to Dapto (8) 330 kV line

+ 0.003432 x North NSW demand

+ 0.0339 x Sydney demand

+ 0.1376 x Canberra demand

+ 0.1678 x South West NSW demand

− 0.01526 x Victorian state grid demand

− 0.00881 x Melbourne demand

− 0.08448 x Central West NSW demand

+ 88.89 (Constant)

− 30 (Operating Margin)

] x 3.654

+ 0.0398 x Vales Pt

+ 0.0393 x Colongra

+ 0.0412 x Eraring 1 & 2

+ 0.1587 x Capital wind farm

+ 0.6634 x Cullerin Range wind farm

+ 0.0018 x Murray

~~[Rating on Marulan to Dapto (8) 330 kV line~~

~~− 0.00372 x NSW demand~~

~~− 30 (Operating Margin)~~

~~] x 3.608~~

~~+ 0.0339 x Colongra~~

+ 0.0332 x Vales Pt

+ 0.0343 x Eraring 1 & 2

+ 0.1721 x Capital

+ 0.6681 x Cullerin Range

– 0.0022 x Murray

3.6 Medium term PASA

The medium term PASA (MT PASA) uses the same terms as the similar terms to ST PASA RHS. except the sub-regional demand type is not available. The values used in MT PASA are different as the MT PASA process has a daily resolution compared to ST PASA's 30 minutes. Examples such as the regional demand which uses the daily maximum and generator / load terms which use the maximum available capacity.

No MT PASA RHS was constructed for the constraint equation N>>N-NIL_28 as it binds rarely in dispatch and pre-dispatch. Other reasons for not constructing an MT PASA RHS include the constraint equation not binding at high demands or high generation output; or the constraint equation cannot be modelled with the terms available in MT PASA.

4 Mainland Contingency FCAS Requirements

4.1 Loss of the largest mainland generator

The "Generation Event" condition covers the loss of the largest single generating unit in a region or regions, except where the loss is the result of losing a network element. This is referred to as MG and is addressed by allocating raise (6-second, 60-second and 5 minute) services. The example below details the system normal MG for "raise 60-second service".

The general form of FCAS constraint equations is given in section 8.35.3 of the CFG. The MG requirement for all NEM regions (known as Global) is given by:

>*All NEM regions (raise 6/60 or 5) ≥*
>
>*Largest generator in NEM*
>
>*– Load relief in NEM regions*

For Raise 1 second[4] service the general form is:

>*All NEM regions (raise 1 second) ≥*
>
>*(Largest generator in NEM*
>
>*– Load relief in NEM regions)*
>
>*x Ratio Calc*

where the "Ratio Calc" is determined based on the MW at risk, regional inertia, and demand. The "Ratio Calc" will calculate the Raise 1 second requirement as a fraction of the Raise 6 second requirement, with a ratio less than 1. Different "Ratio Calcs" will be used for conditions where different frequency containment bands are defined in the Frequency Operating Standards.

4.1.1 Left hand side

FCAS is normally specified on a regional basis, so the LHS of this constraint equation includes all regions (as it is a global requirement). FCAS constraint equations (see CFG section 5.5.12.6.1) can only include factors of 1 on the LHS.

Table 12   FCAS left hand side for mainland generator trip

Region	Factor	Bid Type
QLD1	1	Raise 60 sec
NSW1	1	Raise 60 sec
VIC1	1	Raise 60 sec

---

[4] These constraint equations will be implemented with the introduction of the fast frequency response (FFR) markets in October 2023

Region	Factor	Bid Type
SA1	1	Raise 60 sec
TAS1	1	Raise 60 sec
QLD1	1	Raise 60 sec

4.1.2 Determining the largest single generator

The value for the largest single generating unit in the NEM is determined dynamically in dispatch and pre-dispatch. This is calculated by using the MAX operator (see A.7.5) on each of the single non-aggregate generators. This calculation is used in a number of constraint equations from global requirements to local requirements. As such the calculation is determined separately for each region, using a constraint function (see A.4). Table 13 is implemented as constraint function X_MG_QLD.

Table 13   Pre-dispatch RHS

Term ID	Group ID	SPD ID	SPD type	Factor	Operator
1		BARCALDN.QBCG	T	1	
2		CALL_B_1.QCAB1	T	1	MAX
3		CALL_B_2.QCAB2	T	1	MAX
4		CPP_3.QCAC3	T	1	MAX
5		CPP_4.QCAC4	T	1	MAX
6		GSTONE1.QGLD1	T	1	MAX
7		GSTONE2.QGLD2	T	1	MAX
8		GSTONE3.QGLD3	T	1	MAX
9		GSTONE4.QGLD4	T	1	MAX
10		GSTONE5.QGLD5	T	1	MAX
11		GSTONE6.QGLD6	T	1	MAX
12		KPP_1.QBRA4K	T	1	MAX
13		MPP_1.QBCK1	T	1	MAX
14		MPP_2.QBCK2	T	1	MAX
15		MSTUART1.QMSP1	T	1	MAX
16		MSTUART2.QMSP2	T	1	MAX
17		MSTUART3.QMSP3M	T	1	MAX
18		STAN-1.QSTN1	T	1	MAX
19		STAN-2.QSTN2	T	1	MAX
20		STAN-3.QSTN3	T	1	MAX
21		STAN-4.QSTN4	T	1	MAX
22		SWAN_E.QSWE	T	1	MAX
23		TARONG#1.QTRN1	T	1	MAX
24		TARONG#2.QTRN2	T	1	MAX
25		TARONG#3.QTRN3	T	1	MAX
26		TARONG#4.QTRN4	T	1	MAX
27		TNPS1.QTNT	T	1	MAX
28		W/HOE#1.QWIV1	T	1	MAX

Term ID	Group ID	SPD ID	SPD type	Factor	Operator
29		W/HOE#2.QWIV2	T	1	MAX

Note: the actual constraint function includes more than 50 generators in Queensland. The smaller generators have been removed from this table for simplicity.

4.1.3   Load relief

Frequency in an AC power system is a measure of the rotational speed of AC motors connected to the power system. Thus, when the frequency falls, many of the motors connected to the power system will slow down. As the amount of power consumed by these machines is proportional to their rotational speed, the demand for power seen by the power system will fall when frequency falls. Other equipment may also consume less power when the frequency falls. Conversely, if the frequency is increased, the demand for power will be seen to increase.

The change in demand for a given frequency deviation is thus related to the number of motors connected to the power system, and the size of the frequency deviation. This effect is referred to as 'load relief', and is taken into account when calculating the requirements for FCAS.

Load relief is further detailed in section 8.25.2 of the CFG. For mainland regions the load relief factor is currently 1.50.5% of regional demand for each 0.5 Hz frequency deviation. In Tasmania, the load relief factor is currently 01%. To calculate the load relief for a particular contingency, divide the frequency change by 0.5 and then multiply this by the load relief.

Like the largest generator calculation, the mainland load relief calculation is used in a large number of constraint equations so it is also implemented as the constraint function X_MAIN_LOAD_RELIEF (see Table 14). It also includes the contribution from rooftop PV (the XXX_ASEFS2 terms) so the underlying demand is included the calculation.

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Table 14   Load relief calculation

Term ID	Group ID	SPD ID	SPD type	Factor	Operator
1		QLD1	R	−0.0405	
2		NSW1	R	−0.0405	
3		VIC1	R	−0.0405	
4		SA1	R	−0.0405	
5		NSW_ASEFS2	E	-0.005	
6		QLDSOUTH_ASEFS2	E	-0.005	
7		QLDCENTRAL_ASEFS2	E	-0.005	
8		QLDNORTH_ASEFS2	E	-0.005	
9		VIC_ASEFS2	E	-0.005	
10		SA_ASEFS2	E	-0.005	

The constraint equation RHS references the constraint function ID multiplied by the frequency change divided by 0.5. In this case, the mainland frequency standard for 60 second raise is 0.5 Hz (the same as 6 second – see Appendix A3). Therefore, the factor is 1. However, if this was for raise 5-minute, the frequency standard is 0.15 Hz deviation, and the factor would then be 0.15/0.5 = 0.3.

Tasmania is excluded from this constraint function as it has a different frequency standard compared to that of the mainland and has no load relief. Also, Tasmania has a large amount of non-scheduled generation that is

accounted for in dispatch; hence an analog SPD is used. As the allowable deviation is 2 Hz the factor on Tasmania is 4 x 0.01.

4.1.4 Right hand side

For system normal MG, the raise 60 second algebraic form of the constraint equation is:

All NEM regions (raise 60 second) ≥

Largest single generator in the NEM

– 1 x 0.0105 x Mainland demand

– 4 x 0.01 x Tasmania demand

Table 15 shows how the dispatch RHS would be implemented in AEMO's market systems. The only difference in the pre-dispatch RHS is that term 6 uses the Tasmanian forecast demand (TAS1) with a SPD Type of R.

Table 15   FCAS RHS for largest generator trip

Term ID	Group ID	SPD ID	SPD type	Factor	Operator
1		X_MG_NSW	X	1	
2		X_MG_QLD	X	1	MAX
3		X_MG_SA	X	1	MAX
4		X_MG_VIC	X	1	MAX
5		X_MAIN_LOAD_RELIEF	X	1	
6		TAS_GEN+NON_SCHED	A	–0.04	

4.1.5 Impact of Basslink

The sections above detail the way a constraint equation is constructed for system normal MG for the raise 60 second service. This is not the only constraint equation required; the effect of Basslink must be taken into account.

The constraint equation above is only for the case where Basslink is able to transfer FCAS and the amount of raise 60 second from Tasmania is not restricted by the upper capability of Basslink or the Basslink no-go zone. Two more constraint equations are required (see section 8.95.8 in the CFG) to model Basslink when able and unable to transfer FCAS from Tasmania.

For Basslink in No-Go zone or frequency insensitive:

All Mainland regions (raise) ≥

Largest generator in Mainland regions

– Load relief from Mainland regions

(Swamp if Basslink is able to transfer FCAS)

For Basslink not in No-Go zone and able to transfer FCAS:

All Mainland regions (raise)

– Basslink flow ≥

Largest generator in Mainland regions

– Load relief from Mainland regions

+ 50 (if Basslink < –50)

– Max bid availability (Tasmania to Victoria) (if Basslink > 50)

(Swamp if Basslink is unable to transfer FCAS)

Both the preceding constraint equations are similar in construction to the constraint equation in 4.1.4, except that the Tasmanian load relief is removed and they use the swamping method (see 2.6) to only be active for Basslink able/unable to transfer FCAS.

4.1.6   Implementation

Table 16 shows the three constraint equations discussed, implemented as IDs.

Table 16   Largest generator trip example constraint equation IDs

Condition	Constraint equation ID
Global requirement	F_I+NIL_MG_R60
Basslink unable to transfer FCAS	F_MAIN+NIL_MG_R6
Basslink able to transfer FCAS	F_MAIN++NIL_MG_R5

The largest generation loss is also required for Tasmania.

4.2   Loss of the largest mainland load

The "Load Event" condition covers the loss of the single largest load in a region or group of regions, except where the loss is the result of losing a network element. This is referred to as ML and is addressed by allocating lower

(6 second, 60 second and 5 minute) services. The following example details the system normal ML for a lower

6 second service.

The general form of FCAS constraint equations is given in section 8.35.3 of the CFG. The ML requirement for all NEM regions (known as Global) is given by:

All NEM regions (lower 6/60 or 5) ≥

Largest load in NEM

– Load relief in NEM regions

For Raise 1 second service the general form is:

All NEM regions (lower 1 second) ≥

(Largest load in NEM

– Load relief in NEM regions)

x Ratio Calc

The ratio calc is the same as used in 4.1.

4.2.1 Left hand side

The LHS of the load event constraint equations is similar to the generation event (see 4.1.1) except the bid types are lowers instead of raises.

Table 17   FCAS left hand side for mainland load trip

Region	Factor	Bid Type
QLD1	1	Lower 60 second
NSW1	1	Lower 60 second
VIC1	1	Lower 60 second
SA1	1	Lower 60 second
TAS1	1	Lower 60 second
QLD1	1	Lower 60 second

4.2.2 Determining the largest single load

Unlike the largest generator, the largest single load is not dynamically calculated. Normally the large potlines do not vary their output so the MW value is set as a constant. In the NEM, the largest load is a Boyne Island potline which uses approximately 400 MW.

4.2.3 Right hand side

For system normal ML, the Lower 6 second algebraic form of the constraint equation is:

All NEM Regions (lower 60 second) ≥

Largest single load in the NEM

– 1 x 0.0105 x Mainland demand

– 4 x 0.01 x Tasmania demand

Table 18 shows how the dispatch RHS would be implemented in AEMO's market systems. The load relief calculation is the same as used in the generation event (4.1.3). The only difference in the pre-dispatch RHS, is that term 6 uses the Tasmanian forecast demand (TAS1) with a SPD Type of R.

Table 18   FCAS RHS for largest load trip

Term ID	Group ID	SPD ID	SPD type	Factor	Operator
1		LARGEST_LOAD	C	400	
2		X_MAIN_LOAD_RELIEF	X	1	
3		TAS_GEN+NON_SCHED	A	–0.04	

4.2.4 Impact of Basslink

As with the generation event, two more constraint equations are required (see section 8.95.8 in the CFG) to model Basslink able and unable to transfer FCAS from Tasmania. The constraint equation for Basslink in the no-go zone or frequency insensitive is the same as for the generation event (see 4.1.5):

For Basslink in No-Go zone or frequency insensitive:

All Mainland Regions (lower) ≥

Largest single load in Mainland regions

– Load Relief from Mainland regions

(Swamp if Basslink is able to transfer FCAS)

The constraint equation for Basslink able to transfer FCAS is similar to the constraint equation for the generation event (see 4.1.5)

For Basslink not in No-Go zone and able to transfer FCAS:

All Mainland Regions (Lower)

+ Basslink flow ≥

Largest single load in Mainland regions

– Load Relief from Mainland regions

+ 50 (if Basslink > 50)

– Max Bid Availability (Victoria to Tasmania) (if Basslink < –50)

(Swamp if Basslink is unable to transfer FCAS)

Both the above constraint equations are similar in construction to the first constraint equation, except that the Tasmanian load relief is removed, and they use the swamping method (see 2.6) to only be active for Basslink able/unable to transfer FCAS.

4.2.5   Implementation

Table 19 shows the previous three constraint equations implemented as IDs.

Table 19   Largest load trip example constraint equation IDs

Condition	Constraint equation ID
Global requirement	F_I+NIL_ML_L6
Basslink unable to transfer FCAS	F_MAIN+NIL_ML_L60
Basslink able to transfer FCAS	F_MAIN++NIL_ML_L5

4.3   Network event

The "Network Event" condition is where the loss of a network element (transmission line or transformer) results in the loss of a generator or load. These are referred to as TG and TL respectively.

The general form of the TG constraint equations is the same as for the Generation event except the load relief term has a different factor to take into account the different frequency standard. The same logic applies between the TL and Load event equations.

The TG and TL constraint equations are similar to the MG and ML constraint equations, except that their event size is set to a constant value instead of being dynamically calculated. In rare cases, the TL event is dynamically calculated where other plants affect the MW at risk – for example the MW at risk for the APD potlines in Victoria is affected by the output of the nearby Portland wind farm.

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5   Tasmanian Contingency FCAS Requirements

In Tasmania, calculating the FCAS requirements for contingency events takes into account both the demand and the inertia in Tasmania. The determination of these requirements is complex and requires an iterative calculation process. Regression analysis is used to calculate the factors on the main inputs and this is detailed in limits advice.

5.1   Basslink trip for Victoria to Tasmania transfer

In this example, the raise 6 second service for Basslink tripping at 400ms is detailed. From the limit advice:

Tasmania raise 6 second ≥

Condition	Segment 1	Segment 2
Intercept	−11.728	−30.807
Tasmanian Inertia	−0.0012	−0.0432
Basslink (Tas to Vic)	−0.0399	−0.267
Tasmanian Demand	0.0541	0.15

5.1.1   Left Hand Side

The LHS of segment 1 will only contain Tasmanian Raise 6 second with a factor of 1 (see CFG section 5.5.1).

Table 20   FCAS left hand side for Basslink trip

Region	Factor	Bid type
TAS1	1	Raise 6 second

However, segment 2 will include Basslink on the LHS, as its factor is ≥ 0.07.

Table 21   FCAS left hand side for Basslink trip – segment 2

Region / Interconnector	Factor	Bid type
TAS1	1	Raise 6 second
T-V-MNSP1	0.267	

5.1.2   Dispatch RHS

In the limit advice, the Tasmanian inertia is expressed in MWs. However, this value is provided from AEMO's EMS on a 100 MVA base, so the factor is multiplied by 100. As there is a potentially large number of MW from non-scheduled generators, the region demand term is an analog value instead of the "R" type normally used.

So, for segment 1:

Table 22   FCAS dispatch right hand side – segment 1

Term ID	Group ID	SPD ID	SPD type	Factor	Operator
1		Intercept	C	–11.728	
2		TAS_INERTIA	A	–0.12	
3		T-V-MNSP1	I	–0.0399	
4		TAS_FCSPS_DEMAND	A	0.0541	

So for segment 2:

Table 23   FCAS dispatch right hand side – segment 2

Term ID	Group ID	SPD ID	SPD type	Factor	Operator
1		Intercept	C	–30.807	
2		TAS_INERTIA	A	–4.32	
3		TAS_FCSPS_DEMAND	A	0.15	

5.1.3   Pre-dispatch RHS

The pre-dispatch RHS is the same, except the Tasmanian region demand uses the R type (instead of the analog term) and the inertia value is calculated from a combination of trader terms and analogs. This calculation is implemented as a constraint function.

So, for segment 1:

Table 24   FCAS pre-dispatch right hand side – segment 1

Term ID	Group ID	SPD ID	SPD type	Factor	Operator
1		Intercept	C	–11.728	
2		X_TAS_INERTIA_PD	X	–0.12	
3		T_V_MNSP1	I	–0.0399	
4		TAS1	R	0.0541	

So, for segment 2:

Table 25   FCAS pre-dispatch right hand side – segment 2

Term ID	Group ID	SPD ID	SPD type	Factor	Operator
1		Intercept	C	–30.807	
2		X_TAS_INERTIA_PD	X	–4.32	
3		TAS1	R	0.15	

Table 26 shows the above segments implemented with constraint equation IDs.

Table 26   Basslink trip example constraint equation IDs

Equation	Constraint Equation ID
1	F_T+NIL_BL_R6_1
2	F_T++NIL_BL_R6_2

~~6~~5 FCAS Regulation

The "No Contingency or Load Event" condition in the Frequency Operating Standards covers the minor variations around 50 Hz that continually occur as a result of normal fluctuations in consumer demand and generating unit performance. This condition (commonly referred to as regulation) is addressed by allocating raise and lower regulation services.

AEMO uses a measure of the cumulative frequency deviation (called the time error) to increase the requirement for regulation services beyond a threshold value. Normally, the regulation requirements will be set to a base value (130 MW for raise and 120 MW for lower). If the time error is outside the ±1.5 second band then an extra 60 MW of regulation per 1-second deviation outside this band will be added. This value is capped at 250 MW.

This process applies to the global and NEM Mainland regulation requirement, but does not apply to the regulation requirements for the Tasmanian region. Regulation for Tasmania is nominally set to 50 MW.

~~6.1~~5.1 Left hand side

The LHS of the raise regulation constraint equation is similar to the generation event (see 4.1.1), except that the bid types are raise regulation.

~~Table 27~~Table 20   FCAS left hand side for regulation

Region	Factor	Bid type
QLD1	1	Raise regulation
NSW1	1	Raise regulation
VIC1	1	Raise regulation
SA1	1	Raise regulation
TAS1	1	Raise regulation

~~6.2~~5.2 Dispatch RHS

The general form of FCAS constraint equations is given in section 8.3 of the CFG. The regulation requirement for all NEM regions is given by:

All NEM Regions (Raise regulation) ≥

Maximum (250, Base Raise regulation value (130)

+ (Time Error – 1.5) x 60 when Time Error > 1.5s)

The time error used is the average value of the QLD and NSW time error values from AEMO's Energy Management System.

~~Table 28~~Table 21   FCAS right hand side – regulation example

Term ID	Group ID	SPD ID	SPD type	Factor	Operator
1		FCAS_TIME_ERROR_NSW	A	1	
2		FCAS_TIME_ERROR_QLD	A	1	
3		Constant	C	0.5	PUSH
4			U	1	MUL

Term ID	Group ID	SPD ID	SPD type	Factor	Operator
5		TimeErrorThreshold	C	−1.5	PUSH
6			U	−1	MIN
7		TimeErrorThreshold	C	−1.5	
8		Calc_Increase	C	60	MUL
9		RaiseRegulation	C	130	
10		MaximumRegulation	C	250	PUSH
11		CapRegulation	U	1	MIN

The Pre-dispatch RHS uses a time profiled value for regulation.

The constraint equation in Table 21Table 28 has been implemented with the following constraint equation ID: F_I+NIL_DYN_RREG.

A1. RHS Calculation

Constraint equation RHSs and constraint functions can contain complex calculations and logic. The RHS is based on a reverse polish notation (RPN) calculation engine inside NEMDE. RPN is a method of specifying the process of calculation so that brackets (or parentheses) are not needed. This provides greater flexibility in the construction of constraint equations.

Central to RPN is the use of a stack. In this case, the stack is a collection of numbers where the top item of the stack is the last element placed. A stack behaves like a column of blocks where the access is from the uppermost block down.

In RPN the operands (values) are specified first, followed by the operation:

Addition of two numbers: 5 + 7

RPN equivalent: 5 7 ADD (see the ADD example in section A.7.1)

A.1   Order of operations

Order of operations in constraint RHS calculation is very important. The RHS is evaluated in order starting from term 1. Groups and constraint functions are evaluated separately, and each has their own independent stack.

Initially the stack has a height of one and a value of zero.

1. Increase the stack height by one and add the current term's SPD ID value (Constants have a value of 1) onto the new top element of the stack (this is the same as what the PUSH operator does). This does not occur if the SPD Type is 'U' or the operation is PUSH
2. Perform the current term's Operation on the stack item(s)
3. Multiply the top stack item by the current term's factor
4. ADD the top stack item to the second top item and remove (POP) the top item

For compatibility with pre-RPN constraint equations the first (PUSH) and fourth (ADD) operations are implied (see the STEP example in A.6.1) and as such are transparent to the building or viewing of the constraint. The implied ADD operation does not occur for any operations involving a pre-existing stack; this includes terms with a SPD Type of 'U' or the operations ADD, SUB, MUL, DIV, MAX, MIN, RSD, and RSU.

The value of the top element of the stack on the last term of the constraint equation is the RHS value. The stack height does not have to be one on the last term.

A.2   No RPN operators

Where there are no RPN operators the RHS is evaluated by adding the value of the current term multiplied by the factor to the value at the top of the stack.

In this example the term 1 value of 500 is multiplied by –1 and added to the top of the stack (which in this case is only a height of 1 as there are no RPN operations). Then term 2's value of –1000 is multiplied by 0.5 and added to the top of the stack. The top stack value is now –500 – 500 = –1000. The value of term 3 multiplied by its factor is then added to the top stack element giving a RHS answer of –1000 + 10000 = 9000.

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		BW01.NBAY1	T	−1		500
2		NSW1-QLD1	I	0.5		−1000
3		NSW1	R	1		10000

A.3 Groups

Group terms allow for the collation of a number of terms on a constraint RHS. These act just like brackets in mathematical expressions. Each group has its own stack that is independent from the main RHS calculation. The top item on the group stack is then multiplied by the factor and added to the main RHS calculation.

In the following table the first 4 terms are evaluated similarly to the example in A.2:

$$1 \times 1000 + -1 \times 400 + -0.498 \times 500 + -25 = 326$$

This is then multiplied by 4.197 giving 1368.22. This is then added to the main stack and −1 x 250 added to that giving the RHS value of 1118.22.

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1	5	NRATSE_MNDT8	E	1		1000
2	5	MW_MN_8	A	−1		400
3	5	MW_MN_16	A	−0.498		500
4	5	Operating_Margin	C	−25		
5		HEADROOM	G	4.197		
6		TALWA1.NDT13T	T	−1		250

A.4 Constraint functions

Constraint functions provide constraint builders a method to reference a common RHS calculation in a number of constraint equations. Cases where this is used include:

- Stability (transient or voltage) constraint equations where one equation is defined for system normal and a large number of outage cases use a reduction on the system normal constraint equation.
- Calculation of the largest generator in a region.
- Determining the maximum or minimum bid availability of Basslink taking into account the status of the Basslink frequency controller.

Each constraint function is calculated in a similar manner to a group, in that they have a separate stack to the main constraint equation RHS and they are added to the main constraint equation multiplied by the factor. The SPD ID used in the constraint equation is the ID for the constraint function. Constraint functions can include groups but cannot reference another constraint function.

A.5 Top stack element

The value on the top element of the stack can be multiplied by the factor by using the SPD Type of U. So in the example in A.5 the group on term 5 can be replaced with a stack term and will give the same result.

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		NRATSE_MNDT8	E	1		1000
2		MW_MN_8	A	−1		400

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
3		MW_MN_16	A	–0.498		500
4		Operating_Margin	C	–25		
5		HEADROOM	U	4.197		
6		TALWA1.NDT13T	T	–1		250

A.6 Simple RPN operators

Each of these RPN operators can work on the value for the current term (such as generator MWs or line flow) or on the result of a calculation (group term, constraint function result or on a stack term). When operating on a stack term the result of the operation replaces the value on the top element of the stack.

A.6.1 Step function

The STEP operator returns 1 if the input value is greater than zero, otherwise zero is returned. This value is in turn multiplied by the factor. In the following example the first term's value is greater than 0 so this gives a result of 1. The second term has a value of 0 which the STEP gives a 0. So, the result from the 2 terms is 1.

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		BW01.NBAY1	T	1	STEP	500
2		BW02.NBAY2	T	1	STEP	0

Operators can also act on the stack elements by specifying a SPD Type of U. The following table shows the STEP operation including the implied PUSH and ADD operations:

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		CONSTANT	C	2		
2		BW01.NBAY1	T	1	PUSH	400
3			U	500	STEP	
4			U	1	ADD	

Initially the stack has a height of 1 and a value of zero.

Stack element	Value
1	0 + 2

Term 1 adds the value of the Constant (1) multiplied by the factor (2) to the value of the top of the stack.

Stack element	Value
1	0 + 1 x 2

The PUSH operator on term 2 (see also A.8.1) adds a new element on the top of the stack (increasing the stack height to 2) with the value of BW01.NBAY1 (400) multiplied by the factor (1).

Stack element	Value
2	400 x 1
1	2

Term 3 does a STEP operation on the value of the top item of the stack, multiplies that by 500 and this value replaces the value of the top stack item. In this case since the value of the top element on the stack is greater than zero the STEP operator gives a value of 1 which is then multiplied by 500.

Stack element	Value
2	500 x 1
1	2

Term 4 adds the top two items of the stack together (reducing the stack height to 1) and then multiplies the top item by 1.

Stack element	Value
1	(500 + 2) x 1

The result is 502.

A.6.2   Square

The POW2 operator will squares the input value:

$$Result = (Term\ or\ stack\ value)^2 \times Factor$$

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		NSW1-QLD1	I	1	POW2	100

A.6.3   Cube

The POW3 operator will cube the input value:

$$Result = (Term\ or\ stack\ value)^3 \times Factor$$

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		NSW1-QLD1	I	1	POW3	100

A.6.4   Square Root

The SQRT operator will square root the input value:

$$Result = (Term\ or\ stack\ value)^{1/2} \times Factor$$

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		NSW1-QLD1	I	1	SQRT	100

A.6.5   Absolute Value

The ABS operator will give the absolute value of the input value:

$$Result = |Term\ or\ stack\ value| \times Factor$$

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		NSW1-QLD1	I	1	ABS	100

A.6.6   Negation

The NEG operator will change the sign of the input value:

$$Result = -1 \times (Term\ or\ stack\ value) \times Factor$$

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		NSW1-QLD1	I	1	NEG	100

A.7 Multi-term operators

Each of these RPN operators requires two inputs and can operate on either the current and previous term or on the top and second top elements of the stack. The result is then multiplied by the factor. Operating on the stack is achieved via setting the SPD Type to U and results in removal of the top stack element and the result being applied to the new top stack element.

A.7.1 Add

The ADD operator will add the value of the two terms or the top two elements on the stack and multiply by the factor.

Result = (Term1 + Term 2) x Factor or

(2nd top stack element + Top Stack Element) x Factor

The result from the following calculation is (100 + 200) x 2 = 600

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		MW_MN_8	A	1		100
2		MW_MN_16	A	2	ADD	200

See A.6.1 for an example of an ADD operation on a stack term.

A.7.2 Subtract

The SUB operator will subtract the two term values or the top two elements on the stack and multiply by the factor.

Result = (Term1 – Term 2) x Factor or

(2nd top stack element – Top Stack Element) x Factor

The result from the following calculation is (100 – 200) x 2 = –200

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		MW_MN_8	A	1		100
2		MW_MN_16	A	2	SUB	200

A.7.3 Multiply

The MUL operator will multiply the two term values or the top two elements on the stack and multiply by the factor.

Result = (Term1 x Term 2) x Factor or

(2nd top stack element x Top Stack Element) x Factor

The result from the following calculation is (10 – 20) x 2 = 400

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		MW_MN_8	A	1		10
2		MW_MN_16	A	2	MUL	20

A.7.4   Divide

The DIV operator will divide the two term values or the top two elements on the stack and multiply by the factor.

> Result = (Term1 / Term 2) x Factor or

> (2nd top stack element / Top Stack Element) x Factor

The result from the following calculation is (10 / 20) x 2 = 1

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		MW_MN_8	A	1		10
2		MW_MN_16	A	2	DIV	20

A.7.5   Maximum

The MAX operator will take the maximum of the two term values or the top two elements on the stack and then multiply by the factor.

> Result = Maximum (Term1, Term 2) x Factor or

> Maximum (2nd top stack element, Top Stack Element) x Factor

The result from the following calculation is Maximum (500, 650, 670, 350) x 1 = 670

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		BW01.NBAY1	T	1		500
2		BW02.NBAY2	T	1	MAX	650
3		ER01.NEPS1	T	1	MAX	670
4		TALWA1.NDT13T	T	1	MAX	350

A.7.6   Minimum

The MIN operator will take the minimum of the two term values or the top two elements on the stack and then multiply by the factor.

> Result = Minimum (Term1, Term 2) x Factor or

> Minimum (2nd top stack element, Top Stack Element) x Factor

The result from the following calculation is Minimum (500, 650, 670, 350) x 1 = 350

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		BW01.NBAY1	T	1		500
2		BW02.NBAY2	T	1	MIN	650
3		ER01.NEPS1	T	1	MIN	670
4		TALWA1.NDT13T	T	1	MIN	350

A.8   Stack manipulation

The following operators are for manipulating the items on the stack or increasing the height of the stack.

A.8.1   Push

The PUSH operator increases the stack height by one and places the value of the term multiplied by the factor into the new top stack element. PUSH does not work on SPD Types of U.

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		NSW1-QLD1	I	1		100
2		TALWA1.NDT13T	T	0.5	PUSH	350

After term 2 in the above example the stack will be:

Stack element	Value
2	350 x 0.5
1	100

A.8.2   Duplicate

The DUP operator increases the stack height by 1 and duplicates the value of the second top stack element multiplied by the factor into the new top stack element. DUP only works on SPD Types of U.

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		NSW1-QLD1	I	1		200
2			U	0.5	DUP	

After term 2 in the above example the stack will be:

Stack element	Value
2	200 x 0.5
1	200

A.8.3   Exchange

The EXCH operator exchanges the top and second top elements of the stack and multiplies the top element by the factor. EXCH only works on SPD Types of U.

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		BW01.NBAY1	T	1		660
2		BW02.NBAY2	T	1	PUSH	500
3			U	2	EXCH	

After term 2 in the above example the stack will be:

Stack element	Value
2	500
1	660

After term 3 in the above example the stack will be swapped:

Stack element	Value
2	660 x 2
1	500

A.8.4 Roll stack down

The RSD operator moves the last element on the stack to the top of the stack and multiplies the new top element by the factor. RSD only works on SPD Types of U.

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		BW01.NBAY1	T	1		660
2		BW02.NBAY2	T	1	PUSH	550
3		BW03.NBAY3	T	1	PUSH	500
4			U	2	RSD	

After term 3 in the above example the stack will be:

Stack element	Value
3	500
2	550
1	660

After term 4 in the above example stack element 1 will be moved above stack element 3 and the other stack elements moved down:

Stack element	Value
3	660 x 2
2	500
1	550

A.8.5 Roll stack up

The RSU operator moves the top element on the stack to the last element on the stack and multiplies the new top element by the factor. RSU only works on SPD Types of U.

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		BW01.NBAY1	T	1		660
2		BW02.NBAY2	T	1	PUSH	550
3		BW03.NBAY3	T	1	PUSH	500
4			U	2	RSU	

After term 3 in the above example the stack will be:

Stack element	Value
3	500
2	550

Stack element	Value
1	660

After term 4 in the above example stack element 3 will be moved under stack element 1 and the other stack elements moved up:

Stack element	Value
3	550 x 2
2	660
1	500

A.9 Selection logic

There are 3 methods of logic switching available to constraint equation RHSs. The simplest form is using the STEP operator (see 7.6.1) which provides a simple on / off logic which constraint builders use for swamping constraint equations (see 2.6). The POP/EXLEZ and Branching provide a method of switching between 2 calculations.

A.9.1 POP

The POP operator removes the top element of the stack. It also sets the POP flag (used by the EXLEZ operator) to true if the value of the top element is less than or equal to zero.

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		YWPS1.VYP21	T	1		100
2		YWPS2.VYP22	T	−1	PUSH	350
3			U	1	POP	

After term 2 in the above example the stack will be:

Stack element	Value
2	350 x −1
1	100

The POP operator on term 3 will remove stack element 2. As the value for stack element 2 is negative the flag used by EXLEZ will be set to true.

Stack element	Value
1	100

A.9.2 Exchange if less than or equal to zero

The EXLEZ operator exchanges the top and second top elements of the stack if the POP flag (see 7.9.1) is set to true. Then the top element of the stack is multiplied by the factor. EXLEZ only works on SPD Types of U.

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
1		YWPS1.VYP21	T	1		100
2		YWPS2.VYP22	T	1	PUSH	350

Term ID	Group ID	SPD ID	SPD Type	Factor	Operator	Value
3		YWPS1_220_ON	S	1	POP	0
4			U	2	EXLEZ	

After term 2 in the above example the stack will be:

Stack element	Value
2	350
1	100

The POP operator on term 3 does not remove the top stack element as it is not a SPD Type of U. Instead, the status term is never added to the stack and the value of the term is just used to set the POP flag. As the value for status term is zero the flag is set to true and the EXLEZ operator on term 4 will exchange the stack elements and multiply the top item by 2.

Stack element	Value
2	100 x 2
1	350

A.9.3 Branching type

Branching allows for if/then/else type logic. The branching pre-dates RPN and is less flexible than the POP/EXLEZ operators so now is rarely used.

The use of branching requires three additional parameters to be defined, the parameterterms1, 2, and 3 point to the input value to be tested, the output value if the test is true and the output value if the test is false, respectively. A fourth term is required which links each of these parameters and has a SPD type of B.

Term ID	Group ID	SPD ID	SPD Type	Factor	Value	Param 1	Param 2	Param 3
1	4	YWPS1_220_ON	S	1	1			
2	4	YWPS1.VYP21	T	1	100			
3	4	YWPS2.VYP22	T	1	350			
4			B	1		1	2	3

A2. Selection of Ratings

A2.1 Transmission equipment ratings

AEMO receives line and transformer ratings from each of the network service providers (NSPs) in the NEM. Ratings are provided as static data for use under specific conditions (generally known as "workbook" ratings), dynamically calculated ratings (which calculate the rating based on real time data such as wind speed, ambient temperature, or current line loading) or hand dressed by AEMO in urgent circumstances based on advice from NSPs.

There are 3 different types of ratings used in AEMO's energy management system (EMS). This database of ratings is used by AEMO's EMS to perform network analysis as well as providing the rating values for use in the constraint equations. The 3 rating types used in the EMS are:

- NORM (or Normal). This is the continuous rating of the line or transformer. This value must not be exceeded under pre-contingent conditions.

- EMER (or Emergency). This rating type is used for lines or transformers following a single credible contingency. The EMER rating is used by TransGrid for the majority of its transmission lines for their contingency rating; this is a ~~short term~~short-term rating that has no time limitations on how long this is used. EMER ratings are also used by Powerlink for line ratings and transformers for the transformer short term emergency rating. Where an NSP does not provide an EMER rating the EMER value is the same as the NORM value.

- LDSH (or Load Shed). The LDSH rating type is used for lines or transformers following a single credible contingency. This value has a time limit (usually 15 minutes) by which time the element needs to have returned below the continuous (NORM) rating. Where an NSP does not provide an LDSH rating the LDSH value is the same as used for the EMER type.

For dynamically calculated ratings in Tasmania, South Australia and Queensland each of the NORM, EMER or LDSH fields contain the same value. In Victoria 3 dynamic rating values are provided: continuous (NORM),

15 minute (LDSH), and 5-minute (SCADA value).

A2.2 Ratings used in constraint equations

Rating values are not hard-coded into constraint equations; instead, they use a Rating ID which NEMDE/PASA uses to look up the current value of the rating. This enables constraint equations to use dynamic ratings and ratings which are manually hand dressed. The constraint naming guidelines details the naming of the Rating IDs (section 9.2 – Plant Ratings).

A continuous (NORM) rating is used in constraint equations that manage line flows for no contingencies (such as the South Morang F2 transformer overload in Victoria).

For a credible trip of an element the constraint equations use a short time rating (either EMER or LDSH) and the selection of this is dependent on what rating provided by the TNSP:

- In NSW and Queensland the EMER rating is used unless AEMO has been advised to use a 15 minute rating (for example: Armidale – Tamworth and Murray – Upper Tumut 330kV lines)

- All other regions use the LDSH rating unless AEMO has been advised to use a lower rating by the NSP.

- AEMO's constraint automation will use the EMER rating where one is defined. If an EMER rating is not defined and an LDSH rating is defined then the LDSH rating is used. If both have been defined (as is the case for a number of NSW lines) then the EMER rating is used unless an override has been specified by AEMO's constraint builders (for example: 965 line in NSW).

A2.3 Pre-dispatch / P5 min

~~5 minute~~5-minute pre-dispatch uses the same rating as Dispatch, no matter which RHS is defined to be used.

In pre-dispatch the value of a rating can be overridden by the current dispatch value. This occurs for all ratings, whether they are a workbook rating, dynamic value or hand dressed. The number of pre-dispatch trading intervals the rating is overridden by (known as the EMS Override) is defined for each Rating ID. By default, the override interval is set to:

- 1 for NSW transmission lines only (not transformers)

- 80 for Queensland lines and transformers

- 15 for lines and transformers for all other cases

So, for example, a transmission line with a dynamic rating and an override of 1 will use the current dynamically calculated value in Dispatch and in the first trading interval in pre-dispatch.

The number of intervals can be temporarily changed to better model rating changes in pre-dispatch. For example, if a rating temporarily increased, the number of intervals is set to the estimated duration of the change in rating.

For the trading intervals where an override is not applied then the pre-dispatch rating value is based on the timing supplied by the NSP. In the case of Victoria and Tasmania, which use a temperature-based rating, a default temperature profile is applied to select the rating.

For full details on the seasonal rating timing changes and temperature profiles see the Transmission Equipment Ratings site[5].

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[5] https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/network-data/transmission-equipment-ratings

A3. Frequency Operating Standards

Table 22Table 15 applies to any part of the mainland power system, other than an island.

Table 29Table 22   Mainland frequency operating standards

Condition	Containment	Stabilisation	Recovery
Accumulated time error	5 seconds		
no contingency event or load event	49.75 to 50.25 Hz, 49.85 to 50.15 Hz 99% of the time	49.85 to 50.15 Hz within 5 minutes	
generation event or load event	49.5 to 50.5 Hz	49.85 to 50.15 Hz within 5 minutes	
network event	49 to 51 Hz	49.5 to 50.5 Hz within 1 minute	49.85 to 50.15 Hz within 5 minutes
separation event	49 to 51 Hz	49.5 to 50.5 Hz within 2 minute	49.85 to 50.15 Hz within 10 minutes
multiple contingency event	47 to 52 Hz	49.5 to 50.5 Hz within 2 minute	49.85 to 50.15 Hz within 10 minutes

Table 23Table 16 applies to a mainland island.

Table 30Table 23   Mainland frequency operating standards for a mainland island

Condition	Containment	Stabilisation	Recovery
no contingency event or load event	49.5 to 50.5 Hz		
generation event, load event or network event	49 to 51 Hz	49.5 to 50.5 Hz within 5 minutes	
the separation event that formed the island	49 to 51 Hz or a wider band notified to AEMO by a relevant Jurisdictional Coordinator	49 to 51 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes
multiple contingency event including a further separation event	47 to 52 Hz	49 to 51 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes

Table 24Table 17 applies to any part of Tasmania other than an island.

Table 31Table 24   Tasmanian frequency operating standards

Condition	Containment	Stabilisation	Recovery
Accumulated time error	5 seconds		
no contingency event or load event	49.75 to 50.25 Hz, 49.85 to 50.15 Hz 99% of the time	49.85 to 50.15 Hz within 5 minutes	
generation event, load event or network event	48 to 52 Hz	49.85 to 50.15 Hz within 5 minutes	

Condition	Containment	Stabilisation	Recovery
separation event	47 to 55 Hz	48 to 52 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes
multiple contingency event	47 to 55 Hz	48 to 52 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes

Table 25Table 18 applies to a Tasmanian island.

Table 32Table 25   Tasmanian frequency operating standards for a Tasmanian island

Condition	Containment	Stabilisation	Recovery
no contingency event or load event	49 to 51 Hz		
generation event, load event or network event	48 to 52 Hz (Note 3)	49 to 51 Hz within 10 minutes	
the separation event that formed the island	47 to 55 Hz	48 to 52 Hz within 2 minutes	49 to 51 Hz within 10 minutes
multiple contingency event including a further separation event	47 to 55 Hz	48 to 52 Hz within 2 minutes	49 to 51 Hz within 10 minutes

Note 1: Where the frequency standards do not specify a frequency level for stabilisation within 60 sec, then the

60 sec requirement is referenced on the containment frequency. Where the stabilisation band requires a frequency level to be achieved within 2 minutes, this is taken to be required within 60 sec.

Note 2: the Jurisdictional Coordinator for South Australia has notified AEMO that the frequency band for separation of the South Australian power system is 47 to 52 Hz. The Reliability Panel has anticipated that under-frequency relays will operate at frequency levels in the low end of this range. The fast raise requirement for South Australian islanding will thus be reduced by the expected amount of involuntary load shedding.

Note 3: Where it is not feasible to schedule sufficient FCAS to limit frequency excursions to within this range, operation of the under-frequency load shedding scheme (UFLSS) or over-frequency generator shedding schemes (OFGSS) is acceptable on the occurrence of a further contingency event.

A4. Selection of the Regional Reference Node

Regional Reference Nodes (RRN) are defined (see Appendix E in the marginal loss factors document[6]) as a single notional bus in each region (e.g. Torrens 66 kV bus for SA). Table 26Table 33 details the notional buses defined as RRNs in the NEM.

Table 33Table 26   Regional reference nodes – notional buses

Region	RRN
NSW	Sydney West 330 kV
Queensland	South Pine 275 kV
Victoria	Thomastown 66 kV
South Australia	Torrens Island 66 kV
Tasmania	George Town 220 kV

In all cases the notional bus where the RRN is located is physically made up of a number of bus sections. It is possible that these bus sections can be split for operational reasons such as managing fault levels, line loading or taken out of service for maintenance. When building constraint equations, the RRN is very important as this dictates the orientation of the equation and consequently what generators and interconnectors appear on the LHS (see section 5.5 2.6 in the CFG).

This Appendix provides a guide on how AEMO selects the bus section for use in constraint equations as well as information on the bus sections used as RRNs when developing constraint equations.

In the NER (2A.2.4) the RRN is defined as the bus with the largest load or generation connected. The RRNs in NSW, Victorian and Queensland do not have significant generation connected. However, in SA and Tasmania there are a number of scheduled generators connected to the RRNs. Where the notional bus involves a number of bus sections the bus section used as the RRN in constraint equations needs to be consistently applied across system normal and outage cases except where the bus section is taken out of service. Alternative bus sections are have also been defined (see Table 28Table 35) to cater for the outage of all bus sections comprising the RRN notional bus.

Where a bus is split, the following order is applied in selecting the appropriate section as the RRN:

- Bus selection needs to take into account the market impact of the constraint formulation. For example, if one constraint formulation would constrain on large amounts of generation and the other would constrain off a smaller number of generators, the constrained off formulation should be chosen. For example, the Torrens Island 66 kV east bus as the primary RRN.

- Bus section with the greatest load connected

- Where several bus sections have generation connected, the bus section with the lowest MW capacity of connected scheduled or semi-scheduled generation

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[6] , Loss Factors & Regional Boundaries, Available: http://www.aemo.com.au/Electricity/Market-Operations/Loss-Factors-and-Regional-Boundaries

Based on the above criteria the primary bus sections used as the RRN are detailed in Table 27~~Table 34~~. Table 28~~Table 35~~ lists the bus sections to be used when the primary bus section is out of service.

~~Table 34~~Table 27   Regional reference nodes – primary bus sections

Region	RRN
NSW	Sydney West 330 kV
Queensland	South Pine 275 kV
Victoria	Thomastown 66 kV
South Australia	Torrens Island 66 kV
Tasmania	George Town 220 kV

~~Table 35~~Table 28   Regional reference nodes – alternative bus section

Region	RRN
NSW	Sydney West 330 kV
Queensland	South Pine 275 kV
Victoria	Thomastown 66 kV
South Australia	Torrens Island 66 kV
Tasmania	George Town 220 kV

A5. Measures and Definitions

A5.1 Units of Measure

Abbreviation	Unit of measure
kV	Kilovolt.
MVA	Megavolt amperes.
MW	A Megawatt (MW) is one million watts. A watt (W) is a measure of power and is defined as one joule per second and it measures the rate of energy conversion or transfer.

Glossary

This document uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified.

Term	Definition
Constraint equation	These are the mathematical representations that AEMO uses to model power system limitations and FCAS requirements in National Electricity Market Dispatch Engine (NEMDE).
System normal	The configuration of the power system where: • All transmission elements are in service, or • The network is operating in its normal network configuration.
TNSP	Transmission Network Service Provider.