Regional Benefit Directions Procedures

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Approved by:	Ken Harper
Title:	Group Manager Operational Support
Date:	10 / 10 / 23

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Australian Energy Market Operator Ltd ABN 94 072 010 327

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Current version release details

Version	Effective date	Summary of changes
1.0	10/10/2023	Draft report. Approved for consultation.

1. Introduction

1.1. Purpose and scope

These *Regional Benefit Directions Procedures* (Procedures) are made under the National Electricity Rules (NER) 3.15.8(b2) and have effect only for the purposes set out in those Rules. The National Electricity Rules and the National Electricity Law prevail over this document to the extent of any inconsistency.

These Procedures describe the process and principles AEMO will follow after issuing a *direction* to determine the relative benefit each *region* receives from the issuance of that *direction*, which is referred to in these Procedures as a regional benefit factor (**RBF**). RBFs form part of the calculation AEMO must perform to determine the allocation of *compensation recovery amounts* following the issue of a direction[1].

The value of the RBF affects the amount *Market Customers, Market Generators* and/or *Market Small Generation Aggregators* in a *region* may have to contribute to the cost of the direction. Other factors that affect the allocation of cost to these Registered Participants include the size of the total *compensation recovery amount* (CRA) and the *energy* consumed or generated over the period of the *direction*.

1.2. Definitions and interpretation

1.2.1. Glossary

Terms defined in the National Electricity Law and the NER have the same meanings in these Procedures unless otherwise specified in this clause.

Terms defined in the NER are intended to be identified in these Procedures by italicising them, but failure to italicise a defined term does not affect its meaning.

In addition, the words, phrases and abbreviations in the table below have the meanings set out opposite them when used in these Procedures.

Term	Definition
CRA	*Compensation recovery amount*
FCAS	Frequency control ancillary services
LOR	Lack of reserve
NER	National Electricity Rules
RBF	Regional Benefit Factor being the relative benefit each *region* received from the issuance of a direction

1.2.2. Interpretation

These Procedures are subject to the principles of interpretation set out in Schedule 2 of the National Electricity Law.

[1] In the rare case where the *compensation recovery amount* determined in accordance with 3.15.8(a) and 3.15.8(g) is negative, AEMO pays *Market Customers, Market Generators* or *Market Small Generation Aggregators* as a result of the direction.

2. Application of the Procedures

The Procedures are relevant to the following *directions* types:

- *Energy* directions – *directions* whereby directed participants are required to provide energy. In *energy* directions, *energy* could be:
  - provided by a unit following targets to maintain power system reliability;
  - provided incidentally as a result of providing another service, such as system security or frequency control ancillary services (FCAS) [2];

  The cost of an *energy* direction is recovered from *Market Customers.*
- *Other compensable services* directions – directions whereby directed participants are directed to provide a service that is not:
  - *energy*;
  - *market ancillary services*;
  - a direct substitute for *energy* or a *market ancillary service*; or
  - providing *energy* or *market ancillary services* incidental to the provision of that service[3].

  The cost of an *other compensable services* direction is recovered from *Market Customers, Market Generators* and *Market Small Generation Aggregators*.

The Procedures are not relevant to *market ancillary services* directions[4]. Costs associated with these directions are recovered in line with normal process of recovering the costs of *market ancillary service*, as per NER 3.15.6A.

The Procedures do not apply for directions to *Market Suspension Compensation Claimants* during *Market Suspension Pricing Schedule* periods. Conversely, the Procedures will be relevant during *Market Suspension Pricing Schedule* periods if a *direction* is made to a participant that is not a *Market Suspension Compensation Claimant*, such as a *Scheduled Load* or a *Market Network Service Provider*. Refer to NER 3.15.8A for more information on the regional benefit for *market suspension* compensation recovery.

3. Relevance of the RBF when calculating *compensation recovery amounts* payable

The RBF determined by *AEMO* following the issue of a *direction*[5] is an important component in the calculations *AEMO* must perform under the NER for the cost recovery of directions compensation. This section describes the formulas currently prescribed by clauses 3.15.8(b) and NER 3.15.8(g) of the NER for the calculation of cost recovery amounts, to highlight the

[2] A direction for FCAS may also result in the provision of energy in order to comply with the FCAS direction. Both of these services require compensation as per NER 3.15.7(a). A direction for the provision of FCAS is a *market ancillary services direction*, so the calculation of RBF in these Procedures does not apply. However, compensation for the provision of *energy* is an *energy direction*, so the calculation of RBF in these Procedures is relevant to the *energy* component of the direction.

[3] Services where *energy* is provided incidentally to the service include inertia, voltage control and system strength.

[4] As per footnote 2, the Procedures apply if there is an energy component to an FCAS direction.

[5] See NER 3.15.8(b1))

influence that an RBF has on the amounts payable (or receivable) by a given *Market Customer*, *Market Generator* and/or *Market Small Generation Aggregator*.

For *energy* directions, NER 3.15.8(b) states that *AEMO* must in accordance with the *intervention settlement timetable*, calculate a figure for each *Market Customer* in each *region* by applying the following formula:

$$MCP = \frac{E}{\sum E} \times \frac{\boldsymbol{RB}}{\sum \boldsymbol{RB}} \times CRA$$

For *other compensable service* directions, NER 3.15.8(g) states that any compensation payable by *AEMO* under clause 3.12.2 and 3.15.7 not recovered under clauses 3.15.8(b) and 3.15.8(e) must be recovered from *Market Customers, Market Generators* and *Market Small Generation Aggregators*. *AEMO* must, in accordance with *the intervention settlement timetable*, calculate a figure for each *Market Customer, Market Generator* and *Market Small Generation Aggregator* in each *region* applying the following formula:

$$MCP = \frac{TGE + TSGE - TCE}{RATGE + RATSG - RATCE} \times \frac{\boldsymbol{RB}}{\sum \boldsymbol{RB}} \times CRA \times -1$$

In both of the equations above, **RB** is the RBF determined by AEMO in accordance with these Procedures. For more detail of the variables used in the formulas above, refer to NER 3.15.8(b) and NER 3.15.8(g). Section 6 provides some case studies which describe the calculations of amounts payable in different scenarios.

4. Rules required considerations

When determining the relevant benefit each *region* receives from the issuance of a *direction*, AEMO must take into account, where applicable to the reason the *direction* was given:

- The *load* at risk if the *direction* was not issued or the extent of improvement in available energy reserve in the *region;*
- The capability to control *voltage* in the *region;*
- The capability to control *power system frequency* within the *region;* and
- Any other relevant matters.

5. Principles for determining the RBF

AEMO will apply the following principles when determining the RBF for each *region* for an *energy* or *other compensable service* direction. These principles are expected to hold true despite possible future changes to the structure of the NEM. Figure 1 illustrates the process followed by AEMO to determine the RBF following the issuance of a direction, applying the principles detailed in this section.

Principle 1

For each *direction*, a RBF must be determined for each *region* and this must sum across all regions to a value of 1. The RBF for each *region* must be a value between 0 (no benefit) and 1 (the whole benefit).

Principle 2

The question to be answered is, "who stands to benefit most from the issuance of the direction?" In general, if a *region* doesn't gain any benefit from the *direction*, then the RBF for that *region* should be zero.

Principle 3

The RBF is not determined by the physical location of the *directed participant*, and is independent of whether intervention pricing applies or not[6].

Principle 4

If a *direction* is issued to address a problem confined to a single *region*, such as system strength, voltage control or to address an intra-regional constraint, the RBF of the affected *region* should be assigned a value of 1, and the RBFs for all other *regions* should be zero. This also applies if a *direction* is issued to address a problem in a *region* after it has been electrically disconnected from the NEM, since the *direction* only addresses a problem in the islanded region.

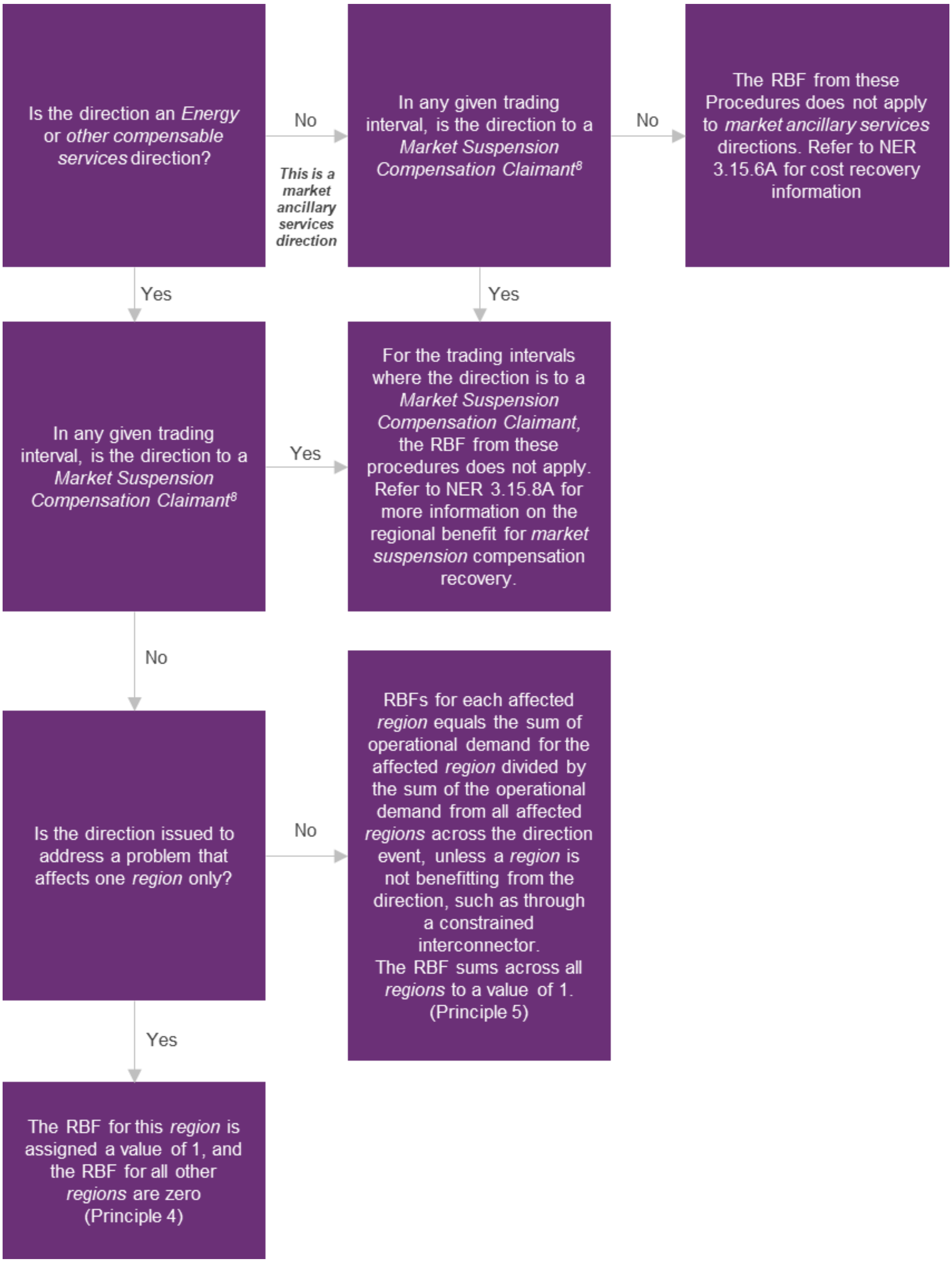
Principle 5

If a *direction* is issued to address a problem that affects multiple regions, the RBFs for each affected *region* should equal the proportion that is the sum of operational demand[7] for the affected *region* divided by the sum of the operational demand from all affected regions across the direction event, unless a *region* is not benefitting from the *direction*, such as through a constrained interconnector. Where a *region* is not benefitting from the *direction*, operational demand in that trading interval will be excluded from the RBF calculation. For examples of this calculation, see Section 6.

[6] Intervention pricing impacts the *compensation recovery amount* for directions, as *Affected Participants*, *Market Customers*, and *Ancillary Service Providers* are entitled to compensation when intervention pricing applies. However, intervention pricing does not influence the calculation of the RBF.

[7] For further details on operational demand, see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf.

Figure 1 Process used to determine the RBF following issuance of a *direction*[8]



[8] A direction to a *Market Suspension Compensation Claimant* can only occur during a *market suspension pricing schedule period* within a *market suspension*. *Market Suspension Compensation Claimants* can include *Scheduled Generators*, *Demand Response Service Providers*, or *Ancillary Service Providers* with *ancillary service generating units* which are also *scheduled generating units.*

6. Case studies

This section explores examples of *energy* or *other compensable service* directions, detailing the methodology and calculation of the RBF for each example *direction* and *region*. These case studies are provided by way of example to demonstrate how the concepts in the Procedures should be applied and do not encompass all potential types of *directions*. Sections 2, 3, 4 and 5 should be applied when determining the RBF for a *direction* regardless of whether the *direction* aligns with a case study.

6.1. South Australia system security direction

6.1.1. Direction details

This case study explores a situation where the synchronous generating units expected to be online in South Australia are inadequate to maintain a secure operating state[9]. In this case, a direction to a synchronous generating unit, such as a gas-fired generator, is required to ensure the power system remains in a secure operating state. A direction could, for example, require an offline synchronous generator to synchronise and follow dispatch targets, or require an online synchronous generator to remain online and follow dispatch targets.

This type of direction often arises when gas-fired generators in South Australia de-commit from the market, either by bidding generation unavailable or at high prices, because pre-dispatch *energy* prices are too low to warrant keeping the generator online or bringing it online.

6.1.2. RBF calculation

The RBF for this direction is 1 for South Australia and zero for all other regions. Key considerations for this calculation are as follows:

- The direction was given for the purpose of providing system security in South Australia.
- Principle 2 - only participants in South Australia stand to benefit from the direction, since the system security issue this direction aims to solve is local to South Australia.
- Principle 3 – although the directed plant is located in South Australia, this does not affect the RBF calculation . Intervention pricing does not apply for South Australian system security directions[10] and this does not affect the RBF calculation.
- Applying Figure 1, the following process for determining the RBF is followed:
  - This **is** an *Energy* direction, as the direction was to provide system security from a gas generating unit, resulting in energy being provided incidentally.
  - The direction **is not** to a *Market Suspension Compensation Claimant* **for all trading intervals**.

[9] On 25 November 2021, AEMO updated its system strength limit advice to reduce the minimum number of gas generation units required to ensure power system security from the equivalent of four large units to two under most operating conditions. Since the updated advice, in most circumstances only two gas generation units have been required to be online for system security purposes. ElectraNet and AEMO continue to assess technical requirements and update operating procedures, for updates refer to: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/related-resources/operation-of-davenport-and-robertstown-synchronous-condensers.

[10] See https://www.aemc.gov.au/sites/default/files/2021-11/Final%20Determination%20-%20ERC0284.pdf.

- The direction **is** issued to address a problem that affects one *region* only, which is South Australia in this case.
- Principle 4 – the RBF for South Australia is 1, and the RBF for all other regions is zero.

6.1.3. Calculation of amounts payable

This section illustrates the hypothetical split of compensation cost recovery for the system security direction to a South Australian gas generator. It shows how the calculation of RBF affects cost recovery from *Market Customers*. The following assumptions are made to calculate the amounts payable:

- There are three *Market Customers* in South Australia with the following adjusted gross energy amounts over the course of the direction[11]:
  - $E_{MC1} = -3{,}000\ MWh$
  - $E_{MC2} = -4{,}500\ MWh$
  - $E_{MC3} = -5{,}000\ MWh$
- The CRA for the direction, which essentially describes the total amount to be recovered, is $10,000.

Section 6.1.2 states the RBF for this direction is 1 for South Australia and zero for all other regions. Therefore, the amount payable[12] by each *Market Customer* outside South Australia is zero, regardless of how large their adjusted gross energy over the course of the direction was. Consistent with Principle 2, *Market Customers* which didn't receive any benefit from the direction do not pay for the direction. Using the above assumptions, the amounts payable for the three *Market Customers* in South Australia are calculated using NER 3.15.8(b)[13] as follows:

$$MCP = \frac{E}{\sum E} \times \frac{RB}{\sum RB} \times CRA$$

$$MCP_{MC1} = \frac{-3{,}000\ MWh}{(-3{,}000\ MWh - 4{,}500\ MWh - 5000\ MWh)} \times \frac{1}{1} \times \$10{,}000 = \$2{,}400$$

$$MCP_{MC2} = \frac{-4{,}500\ MWh}{(-3{,}000\ MWh - 4{,}500\ MWh - 5000\ MWh)} \times \frac{1}{1} \times \$10{,}000 = \$3{,}600$$

$$MCP_{MC3} = \frac{-5{,}000\ MWh}{(-3{,}000\ MWh - 4{,}500\ MWh - 5000\ MWh)} \times \frac{1}{1} \times \$10{,}000 = \$4{,}000$$

As expected, the *Market Customers* in SA are liable for the entire amount payable for the direction:

$$CRA = MCP_{MC1} + MCP_{MC2} + MCP_{MC3}$$

$$CRA = \$2{,}400 + \$3{,}600 + \$4{,}000 = \$10{,}000$$

[11] Negative energy values represent energy consumed.

[12] Or receivable which would be a negative value.

[13] Positive CRA values are assumed when using this formula, meaning AEMO recovers direction compensation costs from participants. This results in positive MCP values, which are amounts participants pay to AEMO as part of the direction cost recovery.

6.2. Queensland and New South Wales reliability direction (energy)

6.2.1. Direction details

This case study explores a situation where the demand in Queensland and New South Wales is approaching energy supply including imports across the interconnector and AEMO is forecasting a lack of reserve (LOR) 2[14] in several hours. In this case, a direction is made to a coal-fired generator in Queensland with additional energy availability, to assist in maintaining a reliable operating state[15] in both Queensland and New South Wales, as there are forecast periods with headroom on the interconnectors between the two regions. A direction could, for example, require an already online coal-fired generator in Queensland to increase its availability offered to the market and ramp up its output at its maximum capability.

This type of *direction* could occur when demand is high, such as when there is an extreme heatwave, and/or when supply is low, such as when there are generator or transmission outages, economic or technical unavailability, low fuel reserves (such as coal stockpiles and gas line pack) or low fuel supply (such as the sun and wind).

6.2.2. RBF calculation

The RBFs determined for this direction are: $RBF_{QLD} = 0.54$, $RBF_{NSW} = 0.46$, $RBF_{VIC} = 0$, $RBF_{TAS} = 0$ and $RBF_{SA} = 0$. Key considerations for this calculation are as follows:

- The *direction* is given for the purpose of maintaining the power system in a reliable operating state in Queensland and New South Wales only. No other regions have reliability concerns. In addition, load is at risk in Queensland and New South Wales if the direction is not issued.
- Principle 2 – only participants in Queensland and New South Wales stand to benefit from the *direction*, since the direction is aimed to improve energy reserves in both *regions*.
- Principle 3 – at times when the interconnectors between Queensland and New South Wales are not constrained, the location of the directed generator (in Queensland) will not determine the RBF. Intervention pricing applies during this direction and this does not impact RBF calculation.
- Applying Figure 1, the following process for determining the RBF is followed:
  - This **is** an *Energy* direction as the *direction* was to increase the availability and generation of a coal generator to maintain a reliable operating state in Queensland and New South Wales.
  - The direction **is not** to a *Market Suspension Compensation Claimant* **for all trading intervals**.
  - The direction **is** issued to address a problem that affects two regions (Queensland and New South Wales).

[14] See https://aemo.com.au/-/media/files/learn/fact-sheets/lor-fact-sheet.pdf?la=en.

[15] A reliable operating state involves meeting demand at all times with available energy supply, including after the largest credible contingency.

– Principle 5 – RBFs for Queensland and New South Wales equal the sum of operational demand for the relevant *region* divided by the sum of the operational demand from both regions across the direction event, unless a *region* is not benefitting from the direction, such as through a constrained interconnector. Details of the operational demand in Queensland and New South Wales and interconnector constraints between the regions are shown in Table 1.

Table 1 Operational demand and interconnector constraints during Queensland and New South Wales reliability direction

Trading interval (hrs)	Queensland operational demand (MW)	New South Wales operational demand (MW)	Interconnector flow constrained from Queensland to New South Wales?
16:30	9,800	12,900	No
17:00	10,000	13,200	No
17:30	10,300	13,100	Yes

For this direction to a Queensland coal generator to address a reliability issue in Queensland and New South Wales, the RBFs are calculated as follows:

$$RBF_{QLD} = \frac{(QLD_{DEMAND1} + QLD_{DEMAND2} + QLD_{DEMAND3})}{(QLD_{DEMAND1} + QLD_{DEMAND2} + QLD_{DEMAND3}) + (NSW_{DEMAND1} + NSW_{DEMAND2} + NSW_{DEMAND3})}$$

$$RBF_{QLD} = \frac{(9{,}800 + 10{,}000 + 10{,}300)}{(9{,}800 + 10{,}000 + 10{,}300) + (12{,}900 + 13{,}200 + 0)} = 0.54$$

$$RBF_{NSW} = \frac{(NSW_{DEMAND1} + NSW_{DEMAND2} + NSW_{DEMAND3})}{(QLD_{DEMAND1} + QLD_{DEMAND2} + QLD_{DEMAND3}) + (NSW_{DEMAND1} + NSW_{DEMAND2} + NSW_{DEMAND3})}$$

$$RBF_{NSW} = \frac{(12{,}900 + 13{,}200 + 0)}{(9{,}800 + 10{,}000 + 10{,}300) + (12{,}900 + 13{,}200 + 0)} = 0.46$$

6.2.3. Calculation of amounts payable

The following assumptions are made to calculate the amounts payable by *Market Customers*:

- There are five *Market Customers*, two in Queensland and three in New South Wales, with the following adjusted gross energy amounts over the course of the direction:

$$MC_{QLD1} = -7{,}000\ MWh$$

$$MC_{QLD2} = -6{,}500\ MWh$$

$$MC_{NSW1} = -6{,}750\ MWh$$

$$MC_{NSW2} = -3{,}750\ MWh$$

$$MC_{NSW3} = -6{,}000\ MWh$$

- The CRA for the direction is $50,000.

Section 6.2.2 states that the RBFs for this direction are: $RBF_{QLD} = 0.54$, $RBF_{NSW} = 0.46$, $RBF_{VIC} = 0$, $RBF_{TAS} = 0$ and $RBF_{SA} = 0$. Given regions other than Queensland and New South Wales had RBFs of zero, the amounts payable[16] by any *Market Customers* outside these regions is zero. Using the above assumptions, the amounts payable are calculated in accordance with NER 3.15.8(b) as follows:

$$MCP = \frac{E}{\sum E} \times \frac{RB}{\sum RB} \times CRA$$

$$MCP_{MCQLD1} = \frac{-7{,}000}{-7{,}000 - 6{,}500} \times \frac{0.54}{1} \times \$50{,}000 = \$14{,}000$$

$$MCP_{MCQLD2} = \frac{-6{,}500}{-7{,}000 - 6{,}500} \times \frac{0.54}{1} \times \$50{,}000 = \$13{,}000$$

$$MCP_{MCNSW1} = \frac{-6{,}750}{-6{,}750 - 3{,}750 - 6{,}000} \times \frac{0.46}{1} \times \$50{,}000 = \$9{,}409$$

$$MCP_{MCNSW2} = \frac{-3{,}750}{-6{,}750 - 3{,}750 - 6{,}000} \times \frac{0.46}{1} \times \$50{,}000 = \$5{,}227$$

$$MCP_{MCNSW3} = \frac{-6{,}000}{-6{,}750 - 3{,}750 - 6{,}000} \times \frac{0.46}{1} \times \$50{,}000 = \$8{,}364$$

6.3. Queensland reliability *direction* (*other compensable services*)

6.3.1. Direction details

This case study explores a situation where there is a forecast LOR2 for the evening peak period in Queensland. In this case, a direction is made to a pumped hydro unit in Queensland, enabling additional water to be stored at height, which can be released to provide additional reserves when required in the evening. The direction is for the pumped hydro unit to make additional capacity available for dispatch and follow dispatch targets.

The direction could occur for the same reasons outlined in Section 6.2.1 with a different type of plant (in this case hydro), available to direct.

6.3.2. RBF calculation

The RBF for this direction is 1 for Queensland and zero for all other regions. Key considerations for this calculation are as follows:

- The direction is given for the purpose of maintaining the power system in a reliable operating state in Queensland. No other regions have reliability concerns. In addition, load is at risk in Queensland if the direction is not issued.
- Principle 2 – only participants in Queensland stand to benefit from the direction, since the system reliability issue this direction aims to solve is local to Queensland.
- Principle 3 – the location of the directed plant in Queensland does not determine the RBF. Intervention pricing applies during this direction and this does not impact RBF calculation.

[16] Or receivable if CRA is a negative value.

- Applying Figure 1, the following process for determining the RBF is followed:
  - This **is** an *Other Compensable Services* direction as the unit acts as a load and consumes energy to meet the direction requirements.
  - The direction **is not** to a *Market Suspension Compensation Claimant* **for all trading intervals**.
  - The direction **is** issued to address a problem that affects one *region* only, which is Queensland in this case.
  - Principle 4 – the RBF for Queensland is 1, and the RBF for all other regions is zero.

6.3.3. Calculation of amounts payable

The following assumptions are made to calculate the amounts payable for *Market Customers*, *Market Generators* and *Market Small Generation Aggregators*:

- There are two *Market Customers* in Queensland. The energy consumed[17] by each *Market Customer* over the course of the direction (customer energy) is as follows:
  - $TCE_{MC1} = -2{,}000\ MWh$
  - $TCE_{MC2} = -4{,}000\ MWh$
- There are three *Market Generators* in Queensland. The energy generated[18] by each Market Generators over the course of the direction (generator energy) is as follows:
  - $TGE_{MG1} = 3{,}000\ MWh$
  - $TGE_{MG2} = 1{,}500\ MWh$
  - $TGE_{MG3} = 2{,}500\ MWh$
- There is one *Market Small Generation Aggregator* in Queensland. The energy generated over the course of the direction (small generator energy) is as follows:
  - $TSGE_{MSGA1} = 10\ MWh$
- The CRA for the direction, which essentially describes the total amount to be recovered, is $20,000.

Section 6.3.2 states the RBF for Queensland is one and the RBF is zero for all other regions. Therefore, the amount payable[19] by each *Market Customer, Market Generator and Market Small Generation Aggregator* outside Queensland is zero. Using the above assumptions, the amounts payable for the *Market Customers, Market Generators and Market Small Generation Aggregator* in Queensland are calculated in accordance with NER 3.15.8(g)[20] as follows:

$$MCP = \frac{TGE + TSGE - TCE}{RATGE + RATSG - RATCE} \times \frac{RB}{\sum RB} \times CRA \times -1$$

[17] Energy values used in recovery are net values (imports-exports). Most often energy will be positive for the generators and negative for the customers, but the opposite could occur.

[18] See footnote 17.

[19] Or receivable which would be a negative value.

[20] Positive CRA values are assumed when using this formula, meaning AEMO recovers direction compensation costs from participants. This results in negative MCP values, which are amounts participants pay to AEMO as part of the direction cost recovery.

- The amount payable for each *Market Customer* in Queensland:

$$MCP_{MC1} = \frac{0 + 0 - (-2{,}000)}{(3{,}000 + 1{,}500 + 2{,}500) + 10 - (-2{,}000 - 4{,}000)} \times \frac{1}{1} \times 20{,}000 \times -1 = -\$3{,}075$$

$$MCP_{MC2} = \frac{0 + 0 - (-4{,}000)}{(3{,}000 + 1{,}500 + 2{,}500) + 10 - (-2{,}000 - 4{,}000)} \times \frac{1}{1} \times 20{,}000 \times -1 = -\$6{,}149$$

- The amount payable for each *Market Generator* in Queensland:

$$MCP_{MG1} = \frac{3{,}000 + 0 - 0}{(3{,}000 + 1{,}500 + 2{,}500) + 10 - (-2{,}000 - 4{,}000)} \times \frac{1}{1} \times 20{,}000 \times -1 = -\$4{,}612$$

$$MCP_{MG2} = \frac{1{,}500 + 0 - 0}{(3{,}000 + 1{,}500 + 2{,}500) + 10 - (-2{,}000 - 4{,}000)} \times \frac{1}{1} \times 20{,}000 \times -1 = -\$2{,}306$$

$$MCP_{MG3} = \frac{2{,}500 + 0 - 0}{(3{,}000 + 1{,}500 + 2{,}500) + 10 - (-2{,}000 - 4{,}000)} \times \frac{1}{1} \times 20{,}000 \times -1 = -\$3{,}843$$

- The amount payable for the *Market Small Generation Aggregator* in Queensland:

$$MCP_{MSGA1} = \frac{0 + 10 - 0}{(3{,}000 + 1{,}500 + 2{,}500) + 10 - (-2{,}000 - 4{,}000)} \times \frac{1}{1} \times 20{,}000 \times -1 = \$15$$

The aggregate MCP recovered from *Market Customers, Market Generators and Market Small Generation Aggregators* in Queensland make up the entire payable amount for direction:

$$CRA = MCP_{MC1} + MCP_{MC2} + MCP_{MG1} + MCP_{MG2} + MCP_{MG3} + MCP_{MSGA1}$$

$$CRA = -\$3{,}075 - \$6{,}149 - \$4{,}612 - \$2{,}306 - \$3{,}843 - \$15 = -\$20{,}000$$