STTM PROCEDURES

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VERSION NO: 13.2~~1~~

EFFECTIVE DATE: ~~21 July 2017~~24 September 2018

VERSION CONTROL

VERSION NUMBER	EFFECTIVE DATE	AUTHORITY	REASON & CHANGES
13.2	24 September 2018	AEMO	Added a custody transfer point for the Sydney hub and a minor update to the note in 7.1.3C.
13.1	21 July 2017	AEMO	Corrected the error in the header and footer of version 13 where it referenced version 12. This version accurately reflects the final determination on 9 December 2016 that applied for version 13.
13	3 January 2017	AEMO	Updated section 9.4.1 to correct and clarify certain aspects of the procedures for the confirmation of individual price step within a contingency gas offer or bid. Updated section 9.3.2 to remove the requirement for AEMO to publish the participant who informed AEMO of a CG trigger event for consistency with the NGR.
12	5 November 2015	AEMO	Updated section 1.2 Definitions to add clear references to ad hoc charge and ad hoc payment. Updated section 9.4.1 Confirmation of availability to add price steps confirmation process and availability. Updated section 9.5 Evidence of delivery of contingency gas to specify requirements of evidence of delivery of contingency gas on both the demand and the supply side, as well as pre-approval evidence methodologies. Updated definitions in section 10.1.3 Mathematical terms to explain the settlement equations. Updated section 10.6 Contingency gas payments and charges to add ad hoc charges and payments for contingency gas resettlement processes and equations.
11	30 September 2015	AEMO	Updated the definition of Material Involuntary Curtailment in section 1.2. Updated section 2.2 to add new Custody Transfer Point (CTP) to the Sydney Hub.
10.1	1 November 2014	AEMO	Updated equation in section 10.8.5 (d) – corrected a typographical error in transposing the final decision to version

VERSION NUMBER	EFFECTIVE DATE	AUTHORITY	REASON & CHANGES
			10.0. This version accurately reflects the final determination on 26 September 2014.
10.0	1 November 2014	AEMO	Amendments to sections 1.2, 10.1.1, 10.1.3, 10.8, 10.10 Explanatory Note and 10.10.3 to implement the changes to the STTM deviations and the settlement surplus and shortfall. Note: Do not use this version. This version is superseded by version 10.1. There is a typographical error in the equation of section 10.8.5 (d). The error is corrected in version 10.1.
9.0	26 September 2014	AEMO	Updated section 2.2 to add new Custody Transfer Point (CTP) to the Sydney Hub. Amended section 5.4 (b)(ii) and (c)(ii) to allow MOS Quantities of zero GJ.
8.0	1 April 2014	AEMO	Amendments to Chapter 5 – Market Operator Service, clause 10.1.3 and clause 4.2 to reduce the MOS period to one month and to extend the eligibility to ofer MOS to trading right holders. Delete clause 2.3 (i) referencing the Doboy distribution meter station
7.2	15 April 2013	AEMO	Amendments to section 7.3 - Market Schedule Variation and section 10.5 - Variation Charges to implement MSV user-to-user transaction.
7.1	7 November 2012	AEMO	Various minor edits required to correct defined terms, spelling errors and missing text. Update clause 2.2(e) to reflect the Albion Park Custody Transfer station.
7.0	13 December 2011	AEMO	Amend section 7.3 to include MSV window and extend to seven days. Amend section 8.2.2 to clarify requirement to set *dpflag* during material curtailment.
6.1	On the Brisbane hub commencement	AEMO	Sections 7.2.1C(b) and 7.2.1C(c) amended to clarify intent. Section 8.4.2 amended to include reference to market administered settlement state.

VERSION NUMBER	EFFECTIVE DATE	AUTHORITY	REASON & CHANGES
	date (1 December 2011)		Corrected reference to subclause in 7.2.5(b)(i). Note: Version 6.1 is relative to version 5.2 (ie. includes all Brisbane hub amendments).
6.0	7 November 2011	AEMO	Sections 7.2.1C(b) and 7.2.1C(c) amended to clarify intent. Section 8.4.2 amended to include reference to market administered settlement state. Note: Version 6.0 amendments apply to version 5.0 (ie. without changes for Brisbane hub)
5.2	To be advised	AEMO	Amendment of 2.3 Brisbane hub custody transfer points
5.1	To be advised	AEMO	Amendments to sections 1.2, 2.3, 7.1.4, 7.2.4, 7.2.5 (new), 8.1, 8.2.2, 8.2.2, 8.2.5, 8.2.6, 8.4.3, 9.2.2, 9.3.3, 9.3.4, 10.1.1, 10.1.2, 10.1.3, 10.8, 12.1, 12.2, and 12.3 to implement the STTM at a Brisbane hub
5.0	16 June 2011	AEMO	STTM validation and price setting process amendments.
4.0	16 June 2011	AEMO	Sections 6.4.2(f) and (h) modified to include MOS gas on registered facility services allowing flow from the hub in the market long offer and market short bid.
3.0	31 March 2011	AEMO	Added new section 7.5 – Ranked deviation quantities information
2.0	1 December 2010	AEMO	Deviation percentage method modified to remove MOS
1.0	7 May 2010	AEMO	Initial STTM Procedures

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CHAPTER 1 - PRELIMINARY

1.1 Introduction

These are the *STTM Procedures* made under section 91BRH of the National Gas Law.

1.2 Definitions

Words and phrases in these Procedures which appear in *italics* are either defined below or have the meaning given to them in Part 20 of the *Rules*. Other terms defined in the *National Gas Law* or the *Rules* have the same meaning when used in these Procedures.

In these Procedures:

ad hoc charge means an amount determined under clause 8.4.4 or 10.6A that is payable to *AEMO* by a *Trading Participant*.

ad hoc payment means an amount determined under clause 8.4.4 or 10.6B that is payable by *AEMO* to a *Trading Participant*.

default gas day capacity means the capacity of an *STTM facility* for a *gas day* that is provided to *AEMO* by the *STTM facility operator* under *rule* 376(1)(f), or determined by *AEMO* under *rule* 377(2) or clause 7.1.3C.

deemed STTM distributor *means a user who is taken to be an STTM distributor in respect of a facility under rule 372A(3)(c)*

deviation settlement function means a mathematical function used to define *deviation charges* and *deviation payments* to be applied to a *Trading Participant's deviation quantities*.

exiting retailer means an *STTM User* in respect of whom responsibility for customers that are connected to an *STTM distribution system* has been assumed by a *retailer of last resort*.

hub price means the price for *gas* at the *hub* determined under clauses 6.5.8(a)(i) and 6.5.8(c) which may represent either the *ex ante market price* or *ex post imbalance price* (as applicable).

incremental price step quantity means the incremental increase in quantity bid or offered in a *price step* which can be *scheduled* within the *capacity limit* of a *registered trading right*.

linepack in respect of an *STTM pipeline* at any time means the total quantity of *gas* in that *STTM pipeline* at that time.

linepack range – See clause 9.2.1.

major retailer of last resort event – See clause 8.3.2(b).

marginal capacity value means the marginal value of a unit of *pipeline hub capacity* determined under clause 6.5.8(a)(ii).

marginal cost means, for a quantity of *gas* purchased, the incremental cost, as implied by the *SPA*, of supplying an increment of that quantity.

marginal value means, for a constrained quantity, the incremental change in cost of the solution to the *SPA* resulting from an incremental change in that constrained quantity.

marginal flow direction value means the *marginal value* of the capability to increase withdrawal from a *hub* on an *STTM facility* when that withdrawal is limited by the flow to the *hub* on that *STTM facility*.

market facility means an *STTM facility* or *STTM distribution system*.

market long offer means an *AEMO* generated offer used in determining the *ex post imbalance price* which reflects the extent to which the gross flows to the *hub* in the *ex ante market schedule* exceed the gross allocations of *gas* flow to the *hub*.

market long offer price means the price associated with the *market long offer*.

market long offer quantity means the quantity associated with the *market long offer*.

market short bid means an *AEMO* generated bid used in determining the *ex post imbalance price* which reflects the extent to which the gross allocations of *gas* flow to the *hub* exceed the gross flows to the *hub* in the *ex ante market schedule*.

market short bid price means the price associated with the *market short bid*.

market short bid quantity means the quantity associated with the *market short bid*.

material involuntary curtailment means any involuntary curtailment of the delivery of *gas* to:

(a) *end users* implemented by an *STTM distributor* that is caused by a *contingency gas trigger event* as specified in *rule* 440(1); or

(b) *deemed STTM distributors*, implemented by the *STTM pipeline operator* by limiting the withdrawal of *gas* from the *STTM pipeline* to a quantity less than the aggregate quantities of *gas* in final nominations accepted by the *STTM pipeline operator* for those *deemed STTM distributors*.

Mathematical Formulation Document means a mathematical description of the implementation of *scheduling* and pricing functionality described in clause 6.5.

maximum gas day capacity means the maximum capacity of an *STTM facility* for a *gas day* that is provided to *AEMO* by the *STTM facility operator* under *rule* 376(1)(g), or determined by *AEMO* under *rule* 377(2), used for the purposes of validating *capacity information* provided under *rule* 414.

minor retailer of last resort event – See clause 8.3.2(a).

operational constraint means technical or operational conditions in a facility that are caused by an unplanned event or circumstances and constrain the ability of that facility to produce, process, store or transport *gas* (as applicable).

Note: The term 'facility' in this definition is not limited to an *STTM facility*.

percentage method means a method for determining *variation charge*s which processes variation quantities as percentages of a reference quantity.

pipeline hub capacity means the quantity of *gas* that an *STTM facility operator* has notified *AEMO* that the *STTM facility* will be able to deliver to the *hub* for the *gas day* represented in the *SPA*, as specified in accordance with *rule* 414.

provisional ex post imbalance price means the price determined in accordance with clause 7.2.1E.

quantity method means a method for determining *variation charge*s which processes variation quantities as GJ quantities.

significant constraint means an *operational constraint* that affects the flow of *gas* to or from a *hub* to the extent specified in clause 8.2.3.

variation settlement function means a mathematical function used to define *variation charges* to be applied to a *Trading Participant's* variation quantities.

1.3 Interpretation

(a) These Procedures are subject to the same principles of interpretation as Part 20 of the *Rules*, unless otherwise stated.

(b) A reference to a ***rule*** is to that *rule* in the *National Gas Rules*

(c) A reference to ***gas*** is to *natural gas*.

1.4 Formulae, Calculations and Values

1.4.1 Gas days

In these Procedures, the following terms may be used to identify a *gas day*:

d refers to a *gas day*.

Example: There will be an *ex ante market price* for a *hub* and an *ex post imbalance price* for a *hub* determined for *gas day* d. On *gas day* d an *ex ante market schedule* for a *hub* will be determined for *gas day* d+1 and an *ex post imbalance price* for a *hub* will be determined for *gas day* d-1.

d-n (1, 2, 3, etc.) refers to the *gas day* that is n or a specified number (1, 2, 3 etc) of *gas days* before *gas day* d.

d+n (1, 2, 3 etc.) refers to the *gas day* that is n or a specified number (1, 2, 3 etc) *gas days* after *gas day* d.

D refers to the *gas day* in respect of which a matter is to be calculated or determined.

Example: An *ex ante market schedule* for *gas day* D will be determined on *gas day* d = D-1 while an *ex post imbalance price* for *gas day* D will be determined on *gas day* d = D+1.

D-n (1, 2, 3, etc.) refers to events or calculations that occur on the *gas day* that is n or a specified number (1, 2, 3 etc) of *gas days* before *gas day* D and which pertain to *gas day* D.

D+n (1, 2, 3 etc.) refers to events or calculations that occur on the *gas day* that is n or a specified number (1, 2, 3 etc) *gas days* after *gas day* D and which pertain to *gas day* D.

n represents a number of *gas days*.

Note: It is not possible to describe differences between values determined for two distinct *gas days* using the term D since labels like D-1 and D+1 can only be used to refer to values that apply for *gas day* D. Only d can be used to describe differences between values determined for different *gas days*.

1.4.2 General

In these Procedures, the following mathematical notations used in formulae and equations have the meanings given in the table below.

Notation	Meaning
$\in$, as in $k \in SP$	This is an example of the usage of the term "element" ($\in$). This notation means that the expression it relates to is evaluated for every possible value of an index (in this case k) within a set (in this case SP).
Σ, as in Σ_k	This is an example of the usage of the term "sum" (Σ). This indicates that any expression following this term is to be evaluated for, and the results summed over, all values of an index (in this case k).
ABS( )	The absolute value of the term within the brackets, eg. ABS(-5) = 5, ABS(5) = 5.
'{ }', '( )' and '[ ]'	A pair of brackets indicates that all calculations between the brackets are to be performed separately from expressions outside the brackets. Different forms of brackets are used solely to make it easier to match the opening bracket of a pair of brackets with the closing bracket.
MAX( )	The maximum (or highest) of two or more values within the brackets, eg. MAX(3,6) = 6, MAX(-4,-7,5) = 5.
MIN( )	The minimum (or lowest) of two or more values within the brackets, eg. MIN(3,6) = 3, MIN(-4,-7,5) = -7.

1.4.3 Null Values

Where no value is required to be set under Part 20 of the *Rules* or these Procedures for a term in a settlement equation, the result of the equation is to be calculated without that term.

1.4.4 Initial values at STTM commencement date

Clauses 12.2 and 12.3 identify values to be used in specified formulae or equations for:

(a) the *gas day* commencing on the *STTM commencement date*; and

(b) where applicable, subsequent *gas days* until sufficient market data is available for the purposes of those formulae or equations.

CHAPTER 2 – HUBS

2.1 Adelaide Hub

For the purposes of *rule* 371(2) of the *Rules*, the following *custody transfer points* comprise the *Adelaide hub*:

(a) *custody transfer point* 1: outlet of the Cavan Interconnection Pipeline from the *STTM pipeline* identified on the *Natural Gas Services Bulletin Board* as the SEA Gas Pipeline with the PlantID of 550052; and

(b) *custody transfer point* 2: outlet of the Taperoo Gate Station from the *STTM pipeline* identified on the *Natural Gas Services Bulletin Board* as the Moomba to Adelaide Pipeline System with the PlantID of 550054; and

(c) *custody transfer point* 3: outlet of the Elizabeth Gate Station from the *STTM pipeline* identified on the *Natural Gas Services Bulletin Board* as the Moomba to Adelaide Pipeline System with the PlantID of 550054; and

(d) *custody transfer point* 4: outlet of the Gepps Cross Gate Station from the *STTM pipeline* identified on the *Natural Gas Services Bulletin Board* as the Moomba to Adelaide Pipeline System with the PlantID of 550054.

2.2 Sydney Hub

For the purposes of *rule* 372(2) of the *Rules*, the following *custody transfer points* comprise the *Sydney hub*:

(a) *custody transfer point* 1: the Wilton Custody Transfer Station from the *STTM pipeline* identified on the *Natural Gas Services Bulletin Board* as the Moomba to Sydney Pipeline System with the PlantID of 520053; and

(b) *custody transfer point* 2: the Horsley Park Custody Transfer Station from the *STTM pipeline* identified on the *Natural Gas Services Bulletin Board* as the Eastern Gas Pipeline with the PlantID of 520047; and

(c) *custody transfer point* 3: the Port Kembla Custody Transfer Station from the *STTM pipeline* identified on the *Natural Gas Services Bulletin Board* as the Eastern Gas Pipeline with the PlantID of 520047; and

(d) *custody transfer point* 4: the connection between the respective pipelines identified in Pipeline Licence No. 30 (Rosalind Park CSM) and Pipeline Licence No. 1 (Wilton to Horsley Park) issued under the *Pipelines Act 1967* of New South Wales, being the Rosalind Park Receipt Point located at chainage KP 15.3 of the Wilton to Horsley Park *natural gas* pipeline; and

(e) *custody transfer point* 5: the Albion Park Custody Transfer Station from the *STTM pipeline* identified on the *Natural Gas Services Bulletin Board* as the Eastern Gas Pipeline with PlantID 520047.

(f) *custody transfer point* 6: from the date identified in a notice published by AEMO, the connection between the respective pipelines identified in Pipeline Licence No. 42 (Hexham to the Newcastle Gas Storage Facility) and Pipeline Licence No. 8 (Killingworth to Kooragang Island) issued under the Pipelines Act 1967 of New South Wales, being the Hexham Reciept Point.

(g) *custody transfer point* 7: from the date identified in a notice published by AEMO, the EGP Wilton Custody Transfer Station from the STTM pipeline identified on the Natural Gas Services Bulletin Board as the Eastern Gas Pipeline with the PlantID of 520047.

~~(g)~~(h) *custody transfer point 8:* the connection point between the ~~AGL~~ Newcastle Gas Storage Facility and the Jemena Secondary Gas Network, being the Tomago Receipt Point.

2.3 Brisbane Hub

For the purposes of *rule* 372A(1) of the *Rules*, the following *custody transfer points* comprise the *Brisbane hub*:

(a) *custody transfer point* 1: the outlet of the *STTM pipeline* identified on the *Natural Gas Services Bulletin Board* as the Roma - Brisbane Pipeline with the PlantID of 540057 at the connection point to the Riverview distribution meter station;

(b) *custody transfer point* 2: the outlet of the Redbank distribution meter station from the *STTM pipeline* identified on the *Natural Gas Services Bulletin Board* as the Roma - Brisbane Pipeline with the PlantID of 540057;

(c) *custody transfer point* 3: the outlet of the *STTM pipeline* identified on the *Natural Gas Services Bulletin Board* as the Roma - Brisbane Pipeline with the PlantID of 540057 at the connection point to the Swanbank facility meter station;

(d) *custody transfer point* 4: the outlet of the *STTM pipeline* identified on the *Natural Gas Services Bulletin Board* as the Roma - Brisbane Pipeline with the PlantID of 540057 at the connection point to the Ellen Grove distribution meter station;

(e) *custody transfer point* 5: the outlet of the *STTM pipeline* identified on the *Natural Gas Services Bulletin Board* as the Roma - Brisbane Pipeline with the PlantID of 540057 at the connection point to the Willawong distribution meter station;

(f) *custody transfer point* 6: the outlet of the *STTM pipeline* identified on the *Natural Gas Services Bulletin Board* as the Roma - Brisbane Pipeline with the PlantID of 540057 at the connection point to the Runcorn distribution meter station;

(g) *custody transfer point* 7: the outlet of the *STTM pipeline* identified on the *Natural Gas Services Bulletin Board* as the Roma - Brisbane

Pipeline with the PlantID of 540057 at the connection point to the Mt Gravatt distribution meter station;

(h) *custody transfer point* 8: the outlet of the *STTM pipeline* identified on the *Natural Gas Services Bulletin Board* as the Roma - Brisbane Pipeline with the PlantID of 540057 at the connection point to the Tingalpa distribution meter station;

(i) [Deleted];

(j) *custody transfer point* 10: the outlet of the *STTM pipeline* identified on the *Natural Gas Services Bulletin Board* as the Roma - Brisbane Pipeline with the PlantID of 540057 at the connection point to the Murarrie distribution meter station;

(k) *custody transfer point* 11: the outlet of the *STTM pipeline* identified on the *Natural Gas Services Bulletin Board* as the Roma - Brisbane Pipeline with the PlantID of 540057 at the connection point to the Gibson Island facility meter station; and

(l) *custody transfer point* 12: the outlet on the *STTM pipeline* identified on the *Natural Gas Services Bulletin Board* as the Roma - Brisbane Pipeline with the PlantID of 540057 at the connection point to the Lytton lateral.

CHAPTER 3 – STTM FACILITIES AND DISTRIBUTION SYSTEM INFORMATION

3.1 Benchmark information

(a) The benchmark information to be provided to AEMO by an *STTM facility operator* for the purposes of *rule* 376(1)(j) is specified in clause 9.2.1.

(b) The benchmark information to be provided to AEMO by an *STTM distributor* for the purposes of *rule* 376(2)(f) is specified in clause 9.2.2*.*

3.2 Other information

(a) No other information is specified for the purposes of *rule* 376(1)(k).

(b) No other information is specified for the purposes of *rule* 376(2)(g).

3.3 Determining STTM Facility Capacity

3.3.1 When AEMO must determine capacity

AEMO must determine the relevant capacity of an *STTM facility* under *rule* 377(2) if the *STTM facility operator* has not provided:

(a) a *default gas day capacity* under *rule* 376(1)(f); or

(b) a *maximum gas day capacity* under *rule* 376(1)(g),

as the case may be, by the start of the *gas day* before the first *gas day* on which the relevant capacity is required for the operation of the *SPA*.

3.3.2 Default gas day capacity

(a) For the purposes of *rule* 377(2), subject to paragraph (b), *AEMO* must determine a *default gas day capacity* for an *STTM facility* as either:

(i) using available metering data for all *custody transfer points* of a *hub* that are connected to that *STTM facility*, the highest quantity of *gas* delivered from the *STTM facility* to the *hub* on any *gas day* in a period that AEMO considers appropriate to determine a reasonable approximation of the highest daily *gas* flows at those points; or

(ii) if metering data is not available or not sufficient, the sum of the *capacity limits* of each *registered facility service* for the *STTM facility* that is *firm capacity*.

(b) In determining a *default gas day capacity*, *AEMO* may take into account any relevant information given to *AEMO* by the *STTM facility operator*.

3.3.3 Maximum gas day capacity

(a) For the purposes of *rule* 377(2), subject to paragraph (b), *AEMO* must determine a *maximum gas day capacity* for an *STTM facility* by multiplying the *default gas day capacity* provided or determined for the *STTM facility* by 1.13.

(b) In determining a *maximum gas day capacity*, *AEMO* may take into account any relevant information given to *AEMO* by the *STTM facility operator*.

3.4 STTM facility operator data

(a) By 3 hours after the beginning of the *gas day* for the following *gas day*, *AEMO* must make available to *Trading Participants* and *publish* as soon as possible after that time:

(i) the *default gas day capacity*; and

(ii) the *maximum gas day capacity*; and

(iii) the validation thresholds to be applied under clause 7.1.3A.

(b) By 10½ hours after the beginning of a *gas day* for that *gas day, AEMO* must make available to *Trading Participants* and *publish* as soon as possible after that time, the validation thresholds to be applied under clause 7.2.1A.

CHAPTER 4 – REGISTRATION OF SERVICES AND TRADING RIGHTS

4.1 Facility Services and Distribution Services

No other information is specified for the purposes of *rule* 381(1)(j).

4.2 Additional trading rights

(a) For the purposes of rule 385(2)(f), the *contract holder* must specify whether an *additional trading right* includes the right to make an associated *MOS increase offer* or *MOS decrease offer*.

CHAPTER 5 - MARKET OPERATOR SERVICE

5.1 [Deleted]

5.2 MOS Estimates

(aa) For the purposes of rule 397(1), AEMO must *publish* its *MOS* estimates for each *MOS period* no later than 40 business days before the start of that *MOS period*.

(ab) For the purposes of rule 397(2), AEMO may *publish* updated *MOS* estimates at any time up to 20 business days before the start of the *MOS period*.

(a) For the purposes of *rule* 397(3), *AEMO* must determine a *MOS* estimate, or updated *MOS* estimate, in accordance with this clause 5.2.

(b) *AEMO* must determine the *MOS* estimate for each *STTM pipeline* based on the range and frequency of *pipeline deviations* which reflect increased flows to the *hub* and *pipeline deviations* which reflect decreased flows to the *hub* on that *STTM pipeline*, to be determined by *AEMO* using:

(i) to the extent accepted by *AEMO* under clause 5.2(d), data provided by the *STTM pipeline operator* for that *STTM pipeline* indicating the forecast pattern of *MOS* allocations for the *MOS period*; otherwise

(ii) to the extent available, *MOS* allocation data held by *AEMO* for that *STTM pipeline* for all or some of the corresponding dates within the *MOS period* but for the prior year; otherwise

(iii) to the extent available, *MOS* allocation data held by *AEMO* for that *STTM pipeline* for the dates not covered by subparagraph (ii) but with similar expected flow characteristics as the dates in the *MOS period*; otherwise

(iv) to the extent accepted by *AEMO* under clause 5.2(f), data about historical *pipeline* nominations and allocations provided by an *STTM pipeline operator*; otherwise

(v) to the extent available, *Natural Gas Services Bulletin Board* data for that *STTM pipeline*, adjusted as *AEMO* reasonably determines to correct for any discrepancies between the delivery points and time intervals represented in that data and the delivery points and time intervals relevant to MOS estimates for that *MOS period*; otherwise

(vi) *MOS* estimates determined by *AEMO* for other *STTM pipelines* for that *MOS period,* adjusted as *AEMO* reasonably determines to allow for the relative capacity of each *pipeline* to *supply* the *hub* and whether it is pressure controlled or flow controlled, and *AEMO* may also adjust any of the above data as it reasonably determines to account for:

(vii) expected growth (or fall) in average and peak *gas* volumes;

(viii) significant changes in the operation of a *pipeline* or the relevant *STTM distribution system*; and

(ix) changes to Part 20 of the *Rules*.

(c) An *STTM pipeline operator* may provide to *AEMO*:

(i) forecast patterns for its *STTM pipeline* of the daily allocation of *MOS* during the *MOS period*, where these are to reflect the range of the expected *pipeline deviations* on that *STTM pipeline*;

(ii) details of the methodology used to derive the forecast patterns in subparagraph (i); and

(iii) details of the source of data used to derive the forecast patterns in subparagraph (i).

(d) *AEMO* must accept a forecast pattern provided in accordance with clause 5.2(c) and received by *AEMO* not later than 50 *business days* prior to the start of a *MOS period*, unless *AEMO* reasonably considers that the data and methodology employed are together an inadequate basis for estimating *MOS* allocations for that *STTM pipeline* and *MOS period*, in which case *AEMO* must provide reasons for not accepting that data.

(e) An *STTM pipeline operator* may provide to *AEMO* historical data about day ahead nominations and allocations for the pipeline at the location of the relevant *hub*.

(f) *AEMO* must accept historical data provided in accordance with clause 5.2(e) and received by *AEMO* not later than 50 *business days* prior to the start of the *MOS period*, unless *AEMO* reasonably considers that the data forms an inadequate basis for estimating *MOS* allocations for that *STTM pipeline* and *MOS period*, in which case *AEMO* must provide reasons for not accepting that data.

(g) Information provided to *AEMO* under clause 5.2(c) or 5.2(e) is confidential information, subject to the requirement for *AEMO* to *publish* its MOS estimate under *rule* 397.

(h) *AEMO* must *publish* the methodology employed to determine the quantities required by *rule* 397 for each *STTM pipeline* and must, before making changes to that methodology, consult with:

(i) Trading Participants; and

(ii) any other person *AEMO* considers would be affected by the proposed changes.

5.3 Request for MOS increase offers and MOS decrease offers

(a) For the purposes of rule 398(1), AEMO must publish a notice requesting *MOS increase offers* and *MOS decrease offers* from *STTM Shippers* for each *STTM pipeline*, no later than 20 business days before the start of a *MOS period*.

(b) For the purposes of rule 398(2)(b), final *MOS increase offers* and *MOS decrease offers* must be submitted to AEMO by 5:00pm on the 11th *gas day* before the start of a *MOS period*.

(c) For the purposes of *rule* 398(2)(d), no other matter is specified.

5.4 MOS increase offers and MOS decrease offers

(a) For the purposes of *rule* 400(4), a *MOS increase offer* or *MOS decrease offer* must comply with the requirements of this clause 5.4.

(b) A *MOS increase offer* must specify at least one and up to ten *price steps* where each *price step* must specify:

(i) a single price, expressed in $/GJ to four decimal places, greater than or equal to zero and less than or equal to the *MOS cost cap*; and

(ii) the maximum quantity of *gas* (excluding that offered in other *price steps*) that the *Trading Participant* is willing to have allocated to it in respect of increased flow to the *hub* at the price specified under paragraph (i), expressed in whole GJ, and being greater than or equal to zero.

(iii) a reference for the *trading right* to which the offer relates, in accordance with the *STTM interface protocol*.

Note: Price steps for *MOS* offers do not represent a cumulative quantity of *gas*.

(c) A *MOS decrease offer* must specify at least one and up to ten *price steps* where each *price step* must specify:

(i) a single price, expressed in $/GJ to four decimal places, greater than or equal to zero and less than or equal to the *MOS cost cap*; and

(ii) the maximum quantity of *gas* (excluding that provided from other *price steps*) that the *Trading Participant* is willing to have allocated to it in respect of decreased flow to the *hub* at the price specified under paragraph (i), expressed in whole GJ, and being greater than or equal to zero.

(iii) a reference for the *trading right* to which the offer relates, in accordance with the *STTM interface protocol*.

Note: Price steps for MOS offers do not represent a cumulative quantity of *gas*.

(d) No two *price steps* in the same *MOS increase offer* or *MOS decrease offer* may have the same price.

(e) An *STTM Shipper* must not submit more than one *MOS increase offer* or more than one *MOS decrease offer* in respect of each *STTM pipeline* for a *MOS period* (but may revise a *MOS increase offer* or *MOS decrease offer* in accordance with *rule* 400(2)).

5.5 MOS Stacks

5.5.1 MOS increase stack

(a) In determining a *MOS increase stack* for an *STTM pipeline* and a *MOS period* in accordance with *rule* 401(1), *AEMO* must include all *price steps* contained in *MOS increase offers* for that *MOS period* and *STTM pipeline* which comply with clause 5.4.

(b) *AEMO* must order a *MOS increase stack* as a list from the lowest to the highest priced *price step* contained in *MOS increase offers*, and *price steps* with the same price may be placed in any order.

(c) For the purpose of *rule* 401(1), the information to be contained in a *MOS increase stack* is:

(i) the unique numeric identifier of that *MOS stack*, where a newer *MOS increase stack* has a higher numeric identifier than an older *MOS increase stack*;

(ii) the date range for which the *MOS increase stack* applies;

(iii) *price steps* listed in the order determined in clause 5.5.1(b); and

(iv) the identifier for each *price step*.

5.5.2 MOS decrease stacks

(a) In determining a *MOS decrease stack* for an *STTM pipeline* and a *MOS period* in accordance with *rule* 401(1) *AEMO* must include all *price steps* contained in *MOS decrease offers* for that *MOS period* and *STTM pipeline* which comply with clause 5.4.

(b) *AEMO* must order a *MOS decrease stack* as a list from the lowest to the highest priced *price step* contained in *MOS decrease offers*, where any *price steps* with the same price may be placed in any order.

(c) For the purpose of *rule* 401(1), the information to be contained in a *MOS decrease stack* is:

(i) the unique numeric *identifier* of that *MOS stack,* where a newer *MOS decrease stack* has a higher numeric *identifier* than an older *MOS decrease stack*;

(ii) the date range for which the *MOS decrease stack* applies;

(iii) *price steps* listed in the order determined in clause 5.5.2(b); and

(iv) the identifier for each *price step*.

5.5.3 Publishing MOS stacks

(a) For the purposes of rule 401(2), AEMO must:

(i) publish the *MOS increase stack* and a *MOS decrease stack* in accordance with rule 401(2)(a); and

(ii) make available to each relevant STTM pipeline operator the information set out in rule 401(2)(b),

No later than 10 *gas days* before the start of the relevant *MOS period.*

CHAPTER 6 - Scheduling and Pricing Algorithm

6.1 The Scheduling and Pricing Algorithm

(a) The *SPA* established and maintained by *AEMO* under *rule* 404 must satisfy the following requirements in addition to those imposed by *rule*s 404 and 405:

the inputs for the *SPA* must be those described in clause 6.4;

in converting inputs to outputs, the functionality of the *SPA* must meet the requirements of clause 6.5; and

the outputs of the *SPA* must be those described in clause 6.6.

(b) *AEMO* must determine that no feasible *scheduling* solution is possible within the constraints imposed under Division 7 of the *Rules* and the *STTM Procedures*, as required by *rule* 405(5), where one or more features required to be implemented by *AEMO* under clause 6.5.7 indicates that there is no feasible *scheduling* solution.

(c) *AEMO* must determine that no feasible *ex post imbalance price* is possible within the constraints imposed under Division 7 of the *Rules* and the *STTM Procedures* where one or more features required to be implemented by *AEMO* under clause 6.5.7 indicates that there is no feasible solution.

6.2 The Mathematical Formulation Document

(a) *AEMO* must establish and maintain a *Mathematical Formulation Document* describing in mathematical terms the problem described in clause 6.5 to be solved in the determination of *provisional schedules* and *ex ante market schedules* (including prices) and *ex post imbalance prices* in accordance with clause 6.1(a).

(b) Subject to paragraph (c), *AEMO* must make the *Mathematical Formulation Document* available to *Trading Participants* on request, and may make it available to any other person on request.

(c) *AEMO* may require a person to execute a confidentiality agreement in a form acceptable to *AEMO* before the *Mathematical Formulation Document* is made available to that person.

(d) *AEMO* must notify *Trading Participants* of any changes made by *AEMO* to the *Mathematical Formulation Document*.

6.3 Incremental Price Step Quantities

(a) This clause relates to valid *ex ante offers*, *ex ante bids* and *price taker bids* for a *hub* as at the time specified in *rule* 415(1)(a) for a *provisional schedule* or *ex ante market schedule,* as applicable.

(b) The *incremental price step quantity* is:

(i) for any *price step* in an *ex ante offer*:

(A) the lesser of the *capacity limit* for the *registered trading right* associated with that *ex ante offer* and the quantity associated with that *price step*; less

(B) the lesser of the *capacity limit* for the *registered trading right* associated with that *ex ante offer* and the quantity associated with the next lowest priced *price step* in that *ex ante offer* (or zero if there is no next lower priced *price step*);

(ii) for any *price step* in an *ex ante bid* associated with an *STTM facility*:

(A) the lesser of the *capacity limit* for the *registered trading right* associated with that *ex ante bid* and the quantity associated with that *price step*; less

(B) the lesser of the *capacity limit* for the *registered trading right* associated with that *ex ante bid* and the quantity associated with the next higher priced *price step* in that *ex ante bid* (or zero if there is no next higher priced *price step*);

(iii) for any *price taker bid* – the lesser of the quantity specified in that *price taker bid* and the *capacity limit* for the *registered trading right* associated with that *price taker bid*; and

(iv) for any *price step* in an *ex ante bid* associated with an *STTM distribution system*:

(A) the lesser of the *capacity limit* for the *registered trading right* associated with that *ex ante bid* less any quantity determined in subparagraph (iii) for that *registered trading right* and the quantity associated with that *price step*; less

(B) the lesser of the *capacity limit* for the *registered trading right* associated with that *ex ante bid* less any quantity determined in subparagraph (iii) for that *registered trading right* and the quantity associated with the next higher priced *price step* in that *ex ante bid* (or zero if there is no next higher priced *price step*).

6.4 SPA Inputs

6.4.1 Provisional schedules and ex ante market schedules

The data to be processed by the *SPA* to produce a *provisional schedule* or an *ex ante market schedule* for a *hub* and a *gas day* are:

(a) valid *ex ante offers, ex ante bids* and *price taker bids* for that *hub* as at the time specified in *rule* 415(1)(a) for a *provisional schedule* or *ex ante market schedule,* as applicable;

(b) the *incremental price step quantities* determined in clause 6.3 for the valid *ex ante offers, ex ante bids* and *price taker bids* described in paragraph (a);

(c) the *capacity limits* for *registered trading rights* associated with *ex ante offers, ex ante bids* and *price taker bids* for that *hub* as at the time specified in *rule* 415(1)(b) for a *provisional schedule* or *ex ante market schedule* as applicable;

(d) the available *capacity information* for each *STTM facility* for that *hub* for that *gas day* in accordance with clause 7.1.3C(c);

(e) the following data for each *registered trading right* associated with *ex ante offers* or *ex ante bids* from *STTM Shippers* for that *hub* as at the time specified in *rule* 415(1)(d) for a *provisional schedule* or *ex ante market schedule* as applicable:

(i) the *STTM facility* associated with that *registered trading right*;

(ii) the priority of the *registered facility service* associated with that *registered trading right*; and

(iii) the flow direction of the *registered facility service* associated with that *registered trading right*;

(f) a *market long offer quantity* of zero;

(g) a *market long offer price* less than *MMP*;

(h) a *market short bid quantity* of zero;

(i) a *market short bid price* greater than *MPC*;

(j) a price, greater than *MPC* but less than the *market short bid price,* to be applied to *price taker bids*; and

(k) any other *SPA* input parameters required to implement the functionality of the *SPA* determined by *AEMO* in accordance with clauses 6.5.6 and 6.5.7.

6.4.2 Ex Post Imbalance Price and Provisional Ex Post Imbalance Price

The data to be processed by the *SPA* to produce an *ex post imbalance price* or an *provisional ex post imbalance price* for a *hub* and a *gas day* are:

(a) valid *ex ante offers*, *ex ante bids* and *price taker bids* for that *hub* as at the time specified in *rule* 415(1)(a) for that *gas day* for the *provisional schedule* or *ex ante market schedule,* as applicable;

(b) the *incremental price step quantities* determined in clause 6.3 for the valid *ex ante offers*, *ex ante bids* and *price taker bids* described in paragraph (a);

(c) the *capacity limits* for *registered trading rights* associated with *ex ante offers*, *ex ante bids* and *price taker bids* for that *hub* as at the time specified in *rule* 415(1)(b) for the *provisional schedule* or *ex ante market schedule* as applicable;

(d) the available *capacity information* for each *STTM facility* for that *hub* for that *gas day* in accordance with clause 7.1.3C(c);

(e) the following data for each *registered trading right* associated with *ex ante offers* or *ex ante bids* from *STTM Shippers* for that *hub* as at the time specified in *rule* 415(1)(d) for the *provisional schedule* or *ex ante market schedule* as applicable:

(i) the *STTM facility* associated with that *registered trading right*

(ii) the priority of the *registered facility service* associated with that *registered trading right*; and

(iii) the flow direction of the *registered facility service* associated with that *registered trading right*;

(f) a *market long offer quantity* equal to the greater of zero and:

(i) the sum over all *registered trading rights* that allow flow to the *hub* on *STTM facilities* on that *gas day* of the *market schedule quantity* of each *registered trading right*; less

(ii) the sum over all *STTM facilities* serving that *hub* of the *allocated quantities* on *registered facility services* that allow flow to the *hub* on that *gas day* as provided to *AEMO* under *rule* 419(1) or substituted under clause 7.2.1C; less

(iii) the sum over all *STTM facilities* serving that *hub* of all *MOS gas* on *registered facility services* that allow flow from the *hub* on that *gas day* as provided to *AEMO* under *rule* 419(1) or substituted under clause 7.2.1C;

(g) a *market long offer price* less than *MMP*;

(h) a *market short bid quantity* equal to the greater of zero and:

(i) the sum over all *STTM facilities* serving that *hub* of the *allocated quantities* on *registered facility services* that allow flow to the *hub* on that *gas day* as provided to *AEMO* under *rule* 419(1) or substituted under clause 7.2.1C; and

(ii) the sum over all *STTM facilities* serving that *hub* of all *MOS gas* on *registered facility services* that allow flow from the *hub* on that *gas day* as provided to *AEMO* under *rule* 419(1) or substituted under clause 7.2.1C; less

(iii) the sum over all *registered trading rights* that allow flow to the *hub* on *STTM facilities* on that *gas day* of the *market schedule quantity* of each *registered trading right*;

(i) a *market short bid price* greater than *MPC*;

(j) a price, greater than *MPC* but less than the *market short bid price,* to be applied to *price taker bids*; and

(k) any other *SPA* input parameters required to implement the functionality of the *SPA* determined by *AEMO* in accordance with clauses 6.5.6 and 6.5.7.

6.5 Functionality of the SPA

6.5.1 Quantities to be determined

Subject to clause 6.5.2, the *SPA* determines values for the following quantities:

(a) the quantity *scheduled* from each *price step* associated with an *ex ante offer*, which must be between zero and the *incremental price step quantity* for that *price step*;

(b) the quantity *scheduled* from each *price step* associated with an *ex ante bid*, which must be between zero and the *incremental price step quantity* for that *price step*;

(c) the quantity *scheduled* from each *price taker bid*, which must be between zero and the *incremental price step quantity* for that *price taker bid*;

(d) the quantity *scheduled* from the *market long offer*, which must be between zero and the *market long offer quantity*; and

(e) the quantity *scheduled* from the *market short bid*, which must be between zero and the *market short bid quantity*.

6.5.2 Maximisation of Value of Trade

(a) In determining the quantities to *schedule,* the *SPA* must maximise:

(i) the sum over all *price taker bids* of:

(A) the quantities *scheduled* from each *price taker bid*;

(B) multiplied by the *price taker bid* price;

(ii) plus the sum over all *price steps* associated with *ex ante bids* of:

(A) the quantities *scheduled* from each *price step*;

(B) multiplied by the price of that *price step*, adjusted as required for tie-breaking;

(iii) plus the quantity *scheduled* from the *market short bid* multiplied by the *market short bid price*;

(iv) less the sum over all *price steps* associated with *ex ante offers* of:

(A) the quantities *scheduled* from each *price step*;

(B) multiplied by the price of that *price step*, adjusted as required for tie-breaking;

(v) less the quantity *scheduled* from the *market long offer* multiplied by the *market long offer price*,

while satisfying the requirements of clauses 6.5.3, 6.5.4, and 6.5.5.

Note: The above formulation makes no reference to tie-breaking or conflict management. These are addressed elsewhere in the Procedures, but as overlays on the above problem rather than part of the problem. Tie-breaking must produce a solution consistent with the above problem in situations where there is more than one solution. Conflict management is employed where the problem has no solution.

(b) In implementing the *SPA*, *AEMO* may:

(i) apply adjustments to the *price taker bid* prices and to *price step* prices referenced in clause 6.5.2(a) to implement the required functionality of clause 6.5.6 provided that, after the application of rounding under clause 6.5.9, those adjustments do not cause reported prices to be economically inconsistent with the prices in *scheduled price steps*; and

(ii) introduce additional terms beyond those described in clause 6.5.2(a) to implement the requirements of clause 6.5.7.

6.5.3 Maintenance of Energy Balance

(a) The *SPA* must *schedule* so that the sum of:

(i) the quantities *scheduled* from each *price step* associated with an *ex ante offer*; plus

(ii) the quantity *scheduled* from the *market long offer*;

equals the sum of:

(iii) the quantities *scheduled* from *price taker bids*; plus

(iv) the quantities *scheduled* from each *price step* associated with an *ex ante bid*; plus

(v) the quantity *scheduled* from the *market short bid*.

(b) In implementing the *SPA*, *AEMO* may include additional terms in the equation described in clause 6.5.3(a) to implement the required functionality of the *SPA* in accordance with clauses 6.5.6 and 6.5.7.

6.5.4 Limits Imposed by Pipeline Capacity

(a) The *SPA* must *schedule* so that the sum of the quantities *scheduled* from each *price step* associated with an *ex ante offer* on an *STTM facility* does not exceed the *pipeline hub capacity* of that *STTM facility*.

(b) The *SPA* must *schedule* so that the sum of the quantities *scheduled* from each *price step* associated with an *ex ante bid* associated with a *registered trading right* for an *STTM facility* does not exceed the sum of the quantities *scheduled* from each *price step* associated with an *ex ante offer* on that *STTM facility*.

(c) In implementing the *SPA*, *AEMO* may include additional terms in the equation described in clauses 6.5.4(a) and 6.5.4(b) to implement the required functionality of the *SPA* in accordance with clauses 6.5.6 and 6.5.7.

6.5.5 Limits Imposed by Registered trading rights

(a) The *SPA* must *schedule* so that the *capacity limit* of a *registered trading right* associated with an *STTM facility* sets the maximum value that can be taken by the total quantity *scheduled* from the *price steps* associated with any *ex ante offer* associated with that *registered trading right*.

(b) The *SPA* must *schedule* so that the *capacity limit* of a *registered trading right* associated with an *STTM facility* sets the maximum value that can be taken by the total quantity *scheduled* from the *price steps* associated with any *ex ante bid* associated with that *registered trading right*.

(c) The *SPA* must *schedule* so that the *capacity limit* of a *registered trading right* associated with an *STTM distribution system* sets the maximum value that can be taken by the sum of:

(i) the quantity *scheduled* from any *price taker bid* associated with that *registered trading right*; and

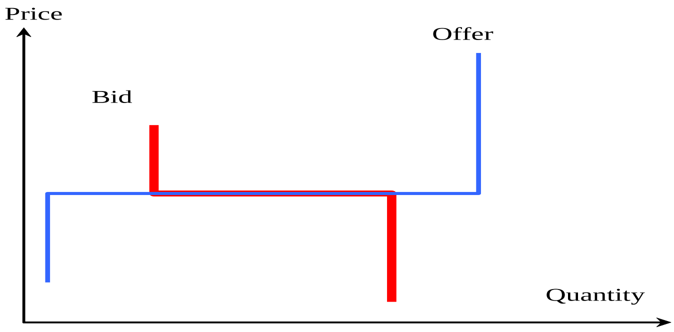
(ii) the total quantity *scheduled* from the *price steps* associated with any *ex ante bid* associated with that *registered trading right*.

(d) In implementing the *SPA*, *AEMO* may include additional terms in the equation described in clauses 6.5.5(a), 6.5.5(b) and 6.5.5(c) to implement the required functionality of the *SPA* in accordance with clauses 6.5.6 and 6.5.7.

6.5.6 Tie-Breaking

(a) If the total quantities *scheduled* from *price steps* associated with *ex ante bids* and the total quantities *scheduled* from *price steps* associated with *ex ante offers* can be varied while still satisfying clause 6.5.2(a) but without changing the value to be maximised under clause 6.5.2(a), the *SPA* must select that set of *scheduled* quantities which satisfies clause 6.5.2(a) while maximising the total quantities *scheduled* from *price steps* associated with *ex ante bids*.

Example: The *supply* and demand curves (whether at the *hub* or on a *pipeline*) cross on a horizontal segment.



All *ex ante bid price steps* will have a very small adjustment made to the step price (e.g. $0.000025/GJ) so that it is always more attractive to *scheduled* tied offers to maximise the bids cleared (both at the *hub* and on an *STTM facility*).

(b) If clause 6.5.3(a) is satisfied but:

(i) all *scheduled price steps* associated with *ex ante bids*, *price taker bids*, and *market short bid*s are either *scheduled* to zero or to the maximum extent allowed by clause 6.5.2(a); and

(ii) all *scheduled price steps* associated with *ex ante offers* and *market long offer*s are either *scheduled* to zero or to the maximum extent allowed by clause 6.5.2(a),

then, for the purpose of clause 6.5.8(a)(i), the highest priced *price step* associated with *ex ante offers* or *market long offer*s with a non-zero *scheduled* quantity will define the *hub price*.

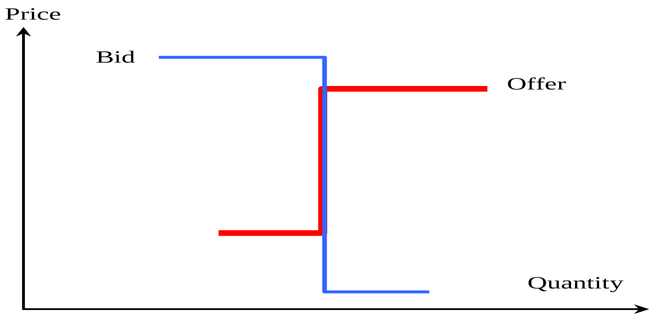
(c) If clause 6.5.4(a) is satisfied for an *STTM facility* but:

(i) all *scheduled price steps* associated with *ex ante bids* on that *STTM facility* are either *scheduled* to zero or to the maximum extent allowed by clause 6.5.2(a); and

(ii) all *scheduled price steps* associated with *ex ante offers* on that *STTM facility* are either *scheduled* to zero or to the maximum extent allowed by clause 6.5.2(a),

then, for the purpose of clause 6.5.8(a)(ii), the difference between the price of the highest priced *price step* associated with *ex ante offers* with a non-zero *scheduled* quantity on that *STTM facility* and the *hub price* will define the *marginal capacity value* for that *STTM facility*.

Example: The *supply* and demand curves (at the *hub* or on *pipelines*) cross on the vertical



If there is any demand to be supplied at the *hub*, a small dummy quantity (0.3 GJ) is inserted in the energy balance equation to reduce total demand fractionally so as to make the last offer *scheduled* marginal, and hence it sets the value.

For an *STTM pipeline*, the capacity of the *pipeline* will be reduced by a small quantity, (eg 0.2 GJ / number of *pipelines* - and no more than 100 *pipelines* are allowed for) so that the *pipeline* cannot be *scheduled* at the end of an offer curve, allowing that offer to set the value.

(d) *Price taker bids* are to be *scheduled* by the *SPA* on a pro rata basis relative to their *incremental price step quantities* except that:

(i) a *price taker bid* can only be *scheduled* to the maximum level allowed by clause 6.5.2(a); and

(ii) a *scheduled* quantity which is limited under subparagraph (i) must be netted from the total quantity to be *scheduled* from those *price taker bids*, which must be pro rated between the other *price taker bids* to the extent permitted under subparagraph (i).

(e) If two or more *price steps* ("tied steps") associated with *ex ante bids* have the same price (the "tied price"), the *SPA* must *schedule* them as follows:

(i) the set of tied steps at each tied price submitted by *STTM Users* are to be treated collectively as a single step (the "*STTM User* collective step") with a weighting equal to the sum of the *incremental price step quantities* of the individual tied steps at that tied price;

(ii) the set of tied steps at each tied price on each *STTM facility* are to be treated collectively as a single step (the "*STTM facility* collective step") with a weighting equal to the sum of the *incremental price step quantities* of the individual tied steps at that tied price;

(iii) the *STTM User* collective step in subparagraph (i) for a tied price and the *STTM facility* collective steps for each *STTM facility* in subparagraph (ii) for a tied price are to be *scheduled* on a pro rata basis relative to their weightings except that:

(A) an *STTM User* collective step or an *STTM facility* collective step can only be *scheduled* up to the maximum level allowed by clause 6.5.2(a); and

(B) a *scheduled* quantity which is limited under subparagraph (A) must be netted from the total quantity to be *scheduled* from those collective steps, which may be *scheduled* between the other collective steps in any manner consistent with clause 6.5.2(a).

Example: Having *scheduled* 25 TJ of consumption from the *hub,* this must be allocated between the bids at the *hub*. Assume the following bids:

- *STTM User* Bid A at *hub* for consumption at *hub* of 6 TJ at $3/GJ
- *STTM User* Bid B at *hub* for consumption at *hub* of 4 TJ at $3/GJ
- *STTM Shipper* Bid at *hub* for *haulage* from the *hub* on *pipeline* 1 with a low *haulage* priority of 10 TJ at $3/GJ.
- *STTM Shipper* Bid at *hub* for *haulage* from the *hub* on *pipeline* 1 with a high *haulage* priority of 10 TJ at $3/GJ.
- *STTM Shipper* Bid at *hub* for *haulage* from the *hub* on *pipeline* 2 with a low *haulage* priority of 20 TJ at $3/GJ.

The solution is to *schedule* 5 TJ from the sum of Bid A and Bid B (without allocating this to those bids), 10 TJ from *pipeline* 1 (without allocating this to bids and ignoring priorities) and 10 TJ to *pipeline* 2 (again without allocating this to bids and ignoring priorities).

(f) If two or more *price steps* ("tied steps") associated with *ex ante bids* of an *STTM User* have the same price (the "tied price") the *SPA* must *schedule* them on a pro rata basis relative to their *incremental price step quantities* except that:

(i) a tied step can only be *scheduled* to the maximum level allowed by clause 6.5.2(a); and

(ii) a *scheduled* quantity which is limited under subparagraph (i) must be netted from the total quantity to be *scheduled* from those tied steps, which must be pro rated between the other tied steps to the extent permitted under subparagraph (i); and

(iii) if the tied steps are included in the *STTM User* collective step under clause 6.5.6(e)(i), the total quantity *scheduled* from those tied steps must equal the value determined for that *STTM User* collective step under clause 6.5.6(e)(iii).

Example: In the previous example 5 TJ was *scheduled* from Bid A and Bid B. This step will pro rate them as 3 TJ from Bid A and 2 TJ from Bid B.

(g) If two or more *price steps* ("tied steps") associated with *ex ante bids* on an *STTM facility* have the same price (the "tied price") then the *SPA* must *schedule* them as follows:

(i) tied steps associated with *registered trading rights* with higher priority of service must be *scheduled* in their entirety before tied steps associated with *registered trading rights* with lower priority are *scheduled*;

Note: Priority 1 is the highest priority.

(ii) two or more tied steps associated with *registered trading rights* with the same priority number must be *scheduled* on a pro rata basis relative to their *incremental price step quantities* except that:

(A) a tied step can only be *scheduled* to the maximum level allowed by clause 6.5.2(a); and

(B) a *scheduled* quantity which is limited under subparagraph (A) must be netted from the quantity to be *scheduled* from those tied steps, which must be pro rated between the other tied steps to the extent permitted under subparagraph (A); and

(iii) if the tied steps on an *STTM facility* are included in an *STTM facility* collective step under clause 6.5.6(e)(ii), the total quantity *scheduled* from those tied steps must equal the value determined for that *STTM facility* collective step under clause 6.5.6(e)(iii).

Example: In the previous example 10 TJ was allocated to *pipeline* 1. The high priority *haulage* would be *scheduled* to 10 TJ and the low priority *haulage* would be *scheduled* to 0 TJ.

If 10 TJ is to be *scheduled* on the *pipeline* (from (d)) and there were a firm (priority 1) bid for 4 TJ and two as available (priority 2) bids each for 10 TJ, then the *schedule* will be 4 TJ on the firm bid and 3 TJ on each of the other two bids.

(h) If two or more *price steps* ("tied steps") associated with *ex ante offers* on different *STTM facilities* have the same price (the "tied price"), the *SPA* must determine the *schedule* of the aggregate of the tied steps for each *STTM facility* as follows:

(i) for each *STTM facility,* determine the sum of the *schedule* quantities of all *ex ante bids* on that *STTM facility*, including quantities determined in accordance with clauses 6.5.6(e) and 6.5.6(g);

(ii) for each *STTM facility,* determine the sum of the *incremental price step quantities* of *ex ante offer price steps* on that *STTM facility* with prices equal to the tied price;

(iii) for each *STTM facility,* determine the sum of the *incremental price step quantities* of *ex ante offer price steps* on that *STTM facility* with prices equal to or less than the tied price;

(iv) determine the weighting for each *STTM facility* at a tied price, being the greater of zero and the lesser of:

(A) the quantity determined in subparagraph (ii); and

(B) the quantity determined in subparagraph (iii) less the quantity determined in subparagraph (i); then

Note: The weighting is at most the quantity of the tied offers, but may be less if some of those offers are required to serve flow already *scheduled* to be withdrawn from the *hub*.

(v) the total *scheduled* quantities from tied steps at a tied price on each *STTM facility* is:

(A) the maximum of:

(1) zero; and

(2) the quantity determined in subparagraph (i) plus the quantity determined in subparagraph (ii) less the quantity determined in subparagraph (iii);

(B) plus a *scheduled* quantity to be pro rated between those *STTM facilities* relative to the weighting determined in (iv) except that:

(1) the total *scheduled* quantities from tied steps at a tied price on each *STTM facility* can only be *scheduled* up to the maximum level allowed by clause 6.5.2(a); and

(2) a total *scheduled* quantity which is limited under subparagraph (1) must be netted from the total quantity to be *scheduled* from the tied steps at the tied price for all *STTM facilities* at the relevant *hub*, which may be *scheduled* between the total *scheduled* quantities from tied steps at the tied price on the remaining *STTM facilities* in any manner consistent with clause 6.5.2(a).

Example: Suppose that the last bids and offers *scheduled* at the *hub price* must *supply* demand of 20 TJ at the *hub*.

Offer 1 on *pipeline* 1 has offered 20 TJ at a cost of $3/GJ and with low *haulage* priority.

Pipeline 1 has *scheduled pipeline* flows away from the *hub* of 10 TJ and Offer 1 on *pipeline* 1 is the only *supply* source on pipeline 1 that can *supply* it.

Offer 2 on *pipeline* 2 has offered 10 TJ at a cost of $3/GJ and with high *haulage* priority.

Offer 3 on *pipeline* 2 has offered 20 TJ at a cost of $3/GJ and with low *haulage* priority.

The first 10 TJ of Offer 1 is committed to serving *gas* flowing from the *hub*, so the tie is between the remaining 10 TJ on *pipeline* 1 and 30 TJ on *pipeline* 2. Of the quantity subject to the tie, *Pipeline* 1 will get 5 TJ and *Pipeline* 2 will get 15 TJ.

The solution taken is allow 15 TJ of flow from *pipeline* 1 (offset by 10 TJ of flow away from the *hub*) and 15 TJ on *pipeline* 2, with a net flow into the *hub* of 20 TJ. This *gas* is not allocated to individual offers at this step.

(i) If two or more *price steps* ("tied steps") associated with *ex ante offers* on a single *STTM facility* have the same price (the "tied price"), the *SPA* must *schedule* them as follows:

(i) tied steps associated with *registered trading rights* with higher priority of service must be *scheduled* in their entirety before tied steps associated with *registered trading rights* with lower priority are *scheduled*;

(ii) two or more tied steps associated with *registered trading rights* with the same priority number must be *scheduled* on a pro rata basis relative to their *incremental price step quantities* except that:

(A) a tied step can only be *scheduled* to the maximum level allowed by clause 6.5.2(a); and

(B) a *scheduled* quantity which is limited under subparagraph (A) must be netted from the quantity to be *scheduled* from those tied steps, which must be pro rated between the other tied steps to the extent permitted under subparagraph (A); and

(iii) if the tied steps on an *STTM facility* are included in a tie between *STTM facilities* under clause 6.5.6(h) then the total quantity *scheduled* from those tied steps must equal the value determined for that *STTM facility* under clause 6.5.6(h)(v).

(j) The *SPA* must determine the solutions to clauses 6.5.6(h) and 6.5.6(i) using *schedule*s which are consistent with this clause 6.5.6 for all *price taker bids* and all *ex ante bid price steps*.

Note: This paragraph is included because paragraphs (f) and (g) actually use the solutions to prior steps as inputs – all the requirements of this clause cannot be solved simultaneously.

6.5.7 Conflict Handling

In implementing the *SPA*, *AEMO* must include additional mathematical terms so as to ensure that the *SPA* can produce quantity and price values where the data presented to the *SPA* means that there would otherwise be no solution that satisfies the requirements of this clause 6.5.

6.5.8 Price Determination by the SPA

(a) When used to produce *provisional schedules* or *ex ante market schedule*s, the *SPA* must determine the following values:

(i) subject to clause 6.5.6(b), a *hub price* which must equal the *marginal cost* of supplying *gas* to the *hub* given the *scheduled* quantities;

(ii) subject to clauses 6.5.6(c) and 6.5.8(b), the *marginal capacity value* for each *STTM facility* which must equal the *marginal value* of the *STTM facility's pipeline hub capacity* given the *scheduled* quantities; and

(iii) subject to clause 6.5.8(b), the *marginal flow direction value* for each *STTM facility* which must equal the *marginal value* of the restriction that flow from the *hub* on that *STTM facility* cannot exceed flow to the *hub* on that *STTM facility* given the *scheduled* quantities.

(b) If an *SPA* solution indicates that both the *marginal capacity value* and the *marginal flow direction value* for an *STTM facility* have non-zero values then:

(i) *marginal capacity value* must be reduced by the value of *marginal flow direction value*; and then

(ii) *marginal flow direction value* must be set to zero.

(c) When used to produce the *ex post imbalance price*, the *SPA* must produce a *hub price* which, subject to clause 6.5.6(b), must equal the *marginal cost* of supplying *gas* to the *hub* given the *scheduled* quantities.

6.5.9 Numeric Rounding

(a) Quantities *scheduled* by the *SPA* from *price taker bids* and *price steps* of *ex ante offers* and *ex ante bids* in accordance with clause 6.5.1 must be rounded to the nearest whole GJ.

(b) The *SPA* is not required to ensure that the total rounded *scheduled ex ante offers* equals the total rounded *scheduled ex ante bids* plus the total rounded *scheduled price taker bids*.

(c) Values determined in accordance with clause 6.5.8 must be rounded to the nearest $0.0001/GJ.

6.6 SPA Outputs

6.6.1 Ex ante market schedules and Provisional schedules

(a) The outputs required from the *SPA* when used to produce *provisional schedules* or *ex ante market schedules* are:

(i) the *market schedule quantity,* or forecast *market schedule quantity*, for each *registered trading right*, being the total of the quantities *scheduled* from each *price step* or *price taker bid* associated with that *registered trading right* in accordance with clause 6.5.1, rounded in accordance with clause 6.5.9;

(ii) subject to paragraph (b), the *ex ante market price*, or forecast *ex ante market price*, being the *hub price* determined in accordance with clause 6.5.8(a)(i), rounded in accordance with clause 6.5.9;

(iii) subject to paragraph (b), the *capacity price*, or forecast *capacity price*, for each *STTM facility*, being the *marginal capacity value* of that *STTM facility* determined in accordance with clause 6.5.8(a)(ii), rounded in accordance with clause 6.5.9; and

(iv) the *pipeline flow direction constraint price*, or forecast *pipeline flow direction constraint price*, for each *STTM facility*, being the *marginal flow direction value* for that *STTM facility* determined in accordance with clause 6.5.8(a)(iii), rounded in accordance with clause 6.5.9.

(b) If:

(i) a *hub price* referred to in clause 6.6.1(a)(ii) exceeds *MPC*, the *ex ante market price*, or forecast *ex ante market price*, must be set equal to *MPC* for the purpose of clause 6.6.1(a)(ii);

(ii) a *hub price* referred to in clause 6.6.1(a)(ii) is less than *MMP*, the *ex ante market price*, or forecast *ex ante market price*, must be set equal to *MMP* for the purpose of clause 6.6.1(a)(ii);

(iii) an *ex ante market price*, or forecast *ex ante market price*, for a *hub* is set under subparagraph (i), the *capacity price*, or forecast *capacity price*, of each *STTM facility* serving that *hub* must, for the purpose of clause 6.6, be set to the greater of:

(A) zero; and

(B) the value of capacity of that *STTM facility* determined under clause 6.6.1(a)(iii), reduced by the same amount by which the *hub price* was reduced under subparagraph (i); and

(iv) the *hub price* less the value of capacity for an *STTM facility* serving that *hub* is less than *MMP*, the *capacity price*, or forecast *capacity price*, of that *STTM facility* must be set to the *ex ante market price*, or forecast *ex ante market price*, less *MMP*.

6.6.2 Ex Post Imbalance Price

(a) For the purpose of *rule* 426, the *ex post imbalance price* produced by the *SPA* is the greater of:

(i) *MMP*; and

(ii) the lesser of *MPC* and the *hub price* determined in clause 6.5.8(c), rounded in accordance with clause 6.5.9.

CHAPTER 7 - GENERAL MARKET OPERATIONS

7.1 Scheduling for the Ex Ante Market

7.1.1 Ex ante offers

(a) For the purposes of *rule* 407(2), an *ex ante offer* must specify:

(i) the *identifier* of the *registered trading right* to which the *ex ante offer* relates; and

(ii) the *gas day* to which the *ex ante offer* relates; and

(iii) at least one and up to ten *price steps*.

(b) The *gas day* specified under clause 7.1.1(a)(ii) must be within the range of *gas days* for which the *registered trading right* is *registered*.

(c) Each *price step* must specify:

(i) a single price, expressed in $/GJ to four decimal places, greater than or equal to *MMP* and less than or equal to *MPC*; and

(ii) the maximum quantity of *gas* that the *STTM Shipper* is willing to deliver to the *hub* at the price specified under subparagraph (i), expressed in whole GJ.

(d) If the price in a *price step* (referred to in this paragraph as the ***higher price step***) is greater than the price in any other *price step* in the *ex ante offer*, then the quantity in the higher price step must be greater than the quantity in that other *price step*.

Note: The purpose of paragraphs (c) and (d) is to ensure that each *price step* represents a cumulative quantity of *gas*, and that prices increase with increasing *price step* quantities.

(e) A *price step* must not have the same price as any other *price step* in the *ex ante offer*.

(f) The total quantity for the *ex ante offer* must be less than or equal to the *capacity limit* of the relevant *registered trading right*.

7.1.2 Ex ante bids

(a) For the purposes of *rule* 408(2), an *ex ante bid* must specify:

(i) the *identifier* of the *registered trading right* to which the *ex ante bid* relates; and

(ii) the *gas day* to which the *ex ante bid* relates; and

(iii) at least one and up to ten *price steps*.

(b) The *gas day* specified under clause 7.1.2(a)(ii) must be within the range of *gas days* for which the *registered trading right* is *registered*.

(c) Each *price step* must specify:

(i) a single price, expressed in $/GJ to four decimal places, greater than or equal to *MMP* and less than or equal to *MPC*; and

(ii) the maximum quantity of *gas* that the *STTM Shipper* or *STTM User* is willing to withdraw from the *hub* at the price specified under subparagraph (i), expressed in whole GJ.

(d) If the price in a *price step* (referred to in this paragraph as the ***higher price step***) is greater than the price in any other *price step* in the *ex ante bid*, then the quantity in the higher price step must be lower than the quantity in that other *price step*.

Note: The purpose of paragraphs (c) and (d) is to ensure that each *price step* represents a cumulative quantity of *gas*, and that prices decrease with increasing price step quantities.

(e) A *price step* must not have the same price as any other *price step* in the *ex ante bid*.

(f) The total quantity for the *ex ante bid* must be less than or equal to the *capacity limit* of the relevant *registered trading right* less any quantity included in a *price taker bid* for that *registered trading right* for the *gas day*.

7.1.3 Price taker bids

(a) For the purposes of *rule* 409(2), a *price taker bid* must specify:

(i) the *identifier* of the *registered trading right* to which the *price taker bid* relates; and

(ii) the *gas day* to which the *price taker bid* relates; and

(iii) the total quantity of *gas* that the *STTM User* expects to withdraw from the *hub*, expressed in whole GJ.

(b) The *gas day* specified under clause 7.1.3(a)(ii) must be within the range of *gas days* for which the *registered trading right* is *registered*.

(c) The total quantity for the *price taker bid* must be less than or equal to the *capacity limit* of the relevant *registered trading right* less any quantity included in an *ex ante bid* for that *registered trading right* for the *gas day*.

7.1.3A Validation of capacity information

(a) For the purposes of *rule* 414(2A) *AEMO* must validate information included in a notice provided under *rule* 414(1), in accordance with the requirements of the *STTM Interface Protocol*.

(b) *AEMO* must promptly notify the relevant *STTM facility operator* if information is not provided under *rule* 414(1), or if information provided under *rule* 414(1) fails validation.

7.1.3B Validation of capacity information

For the purpose of *rule* 414(2B), if notified by *AEMO*, an *STTM facility operator* must:

(a) update a notice provided under *rule* 414(1) by 4½ hours after the beginning of a *gas day*; or

(b) on the *gas day* before the *gas day* to which that information relates, confirm a notice provided under *rule* 414(1) by 4½ hours after the beginning of a *gas day*.

7.1.3C Validation of capacity information

(a) If *AEMO* receives an updated notice under clause 7.1.3B, it must substitute the values provided in that notice for those provided in the original notice provided under *rule* 414(1).

(b) If an *STTM facility operator* does not give *AEMO* a notice in accordance with *rule* 414(1) and does not subsequently provide an updated notice in accordance with clause 7.1.3B in respect of a *gas day*, then *AEMO* must use:

(i) if available, the *capacity information* provided under *rule* 414 on the gas day that is 2 *gas days* before the *gas day* to which that information relates; otherwise

(ii) if available, the *capacity information* provided under *rule* 414 on the gas day that is 3 *gas days* before the *gas day* to which that information relates; otherwise

(iii) the *registered* quantity of gas provided under *rule* 376(1)(f) or determined under *rule* 377(2) for that *gas day*.

(c) For the purposes of 6.4.1, *AEMO* must use:

(i) if available as at 4½ hours after the beginning of a *gas day*, the last notice for that *hub* and *gas day* provided to *AEMO* in accordance with *rule* 414(1) or clause 7.1.3B; otherwise

(ii) the *capacity information* determined by *AEMO* in accordance with paragraph (b).

Note: *AEMO* will determine *capacity information* by using data provided at 3 hours after the beginning of a *gas day* that passes validation. If AEMO has received capacity information, but that capacity information has an unconfirmed warning, then~~, if this is unavailable~~ *AEMO* will use updated information provided by 4½ hours after the beginning of a *gas day* that passes validation or is confirmed by the *STTM facility operator*. For the avoidance of doubt, the only way a STTM facility operator can obtain an extra 1½ hour to submit their capacity nomination is to have a warning notice that has NOT been confirmed. If no data has passed validation or been confirmed, *AEMO* will use the most recently provided data. *AEMO* will only use a default capacity if the *STTM facility operator* has not provided any data.

7.1.4 Publication of capacity information

For the purpose of *rule* 414(3), the most recent *capacity information* must be made available to Trading Participants and other persons authorised by *AEMO*:

(a) promptly after 3 and 4½ hours after the beginning of a *gas day* that is 3 *gas days* before the *gas day* to which that information relates; and

(b) promptly after 3 and 4½ hours after the beginning of a *gas day* that is 2 *gas days* before the *gas day* to which that information relates; and

(c) promptly after 3 and 4½ hours after the beginning of a *gas day* that immediately precedes the *gas day* to which that information relates.

7.1.5 Issue of Schedules

(a) For the purposes of *rule* 415(2)(a)(v), no other details are required to be determined for a *schedule* to be taken to be issued.

(b) For the purposes of *rule* 415(2)(b)(iv), no other details are required to be made available for a *schedule* to be taken to be issued.

(c) For the purposes of *rule* 415(3), *AEMO* must make available to each *STTM distributor* at a *hub*, other than the *Brisbane hub*, the following information in relation to a *provisional schedule* or *ex ante market schedule* for that *hub*:

(i) the quantity of *gas scheduled* from *ex ante bids* for each *STTM User*;

(ii) the quantity of *gas scheduled* from *price taker bids* for each *STTM User*; and

(iii) the quantity of *gas* not *scheduled* from *price taker bids* for each *STTM User*.

7.2 Allocations

7.2.1 Content of STTM facility allocation notices

(a) For the purposes of *rule* 419(2)(c), an allocation notice for an *STTM facility* must contain the following additional information:

(i) the *gas day* to which the allocation notice relates;

(ii) the *identifier* of the *STTM facility* to which the allocation notice relates; and

(iii) the *identifier* of each *registered facility service* that is provided by means of the relevant *STTM facility*.

(b) For the purposes of *rule* 419(4), a *billing period allocation statement* must be provided to *AEMO* four *business days* prior to:

(i) the date on which *AEMO* must issue a *preliminary statement*, *final statement* or *revised statement* in accordance with Division 10 of the *Rules*; or

(ii) any date in respect of which *AEMO* advises the relevant *allocation agent* that it intends to issue a *revised statement*.

7.2.1A Validation of STTM facility allocation data

(a) For the purposes of *rule* 419(2A) *AEMO* must validate information included in an allocation notice provided under *rule* 419(1), in accordance with the *STTM Interface Protocol*.

(b) *AEMO* must promptly notify the relevant *allocation agent* for an *STTM facility* if information is not provided under *rule* 419(1), or information provided under *rule* 419(1) fails validation.

7.2.1B Update of facility allocations

For the purpose of *rule* 419(2B), if notified by *AEMO*, an *allocation agent* for an *STTM facility* must update or confirm an allocation notice provided under *rule* 419(1) by 8½ hours after the beginning of a *gas day*.

7.2.1C Substitution of facility allocations

(a) If *AEMO* receives an updated allocation notice under clause 7.2.1B it must substitute the values provided in that allocation notice for those provided in the original allocation notice under *rule* 419(1).

(b) *AEMO* must retain the values provided in an earlier allocation notice if it:

(i) does not receive an updated allocation notice under clause 7.2.1B; or

(ii) the updated allocation notice is rejected in accordance with *rule* 419(3).

(c) If:

(i) *AEMO* does not receive a notice in accordance with *rule* 419(1) and clause 7.2.1B by 8½ hours after the beginning of a *gas day*; or

(ii) *AEMO* rejects an allocation notice under *rule* 419(3) and has not received another allocation notice for that *STTM facility*,

then *AEMO* must:

(iii) determine the *STTM facility allocation* for each *registered facility services* for the *gas day* in respect of that *STTM facility* as if:

(A) the quantities of *gas* supplied to or withdrawn from the *hub* using the *registered facility services* on that *gas day* were equal to the quantities that were *scheduled* to be supplied or withdrawn for that service in the *ex ante market schedule* for that *gas day*; and

(B) no *MOS gas* was allocated to the *registered facility service* for that *gas day*.

(d) *AEMO* must notify *Trading Participants* and other persons authorised by *AEMO*:

(i) promptly after 4½ hours after the beginning of a *gas day*, if an allocation notice is; not provided under *rule* 419(1), or is rejected under *rule* 419(3) or if an allocation notice provided under *rule* 419(1) fails validation; and

(ii) promptly after 8½ hours after the beginning of a *gas day*, of a confirmation or substitution made under paragraphs (a), (b) or (c).

7.2.1D Ex post imbalance price

For the purposes of *rule* 426(2), *AEMO* must determine the *ex post imbalance price* for a *hub* for a *gas day* using:

(a) the inputs used to determine the *ex ante market schedule* for that *hub* and *gas day* in accordance with *rule* 415(1); and

(b) the *market scheduled quantities* specified in the *ex ante market schedule* for that *hub* and *gas day*; and

(c) the *STTM facility allocations* for that *hub* and *gas day*

Note: *STTM facility allocation* refers to the final number that is determined by *AEMO* in accordance with *rule* 419 or clause 7.2.1C not to the notices provided by participants under *rule* 419 or clause 7.2.1B.

7.2.1E Provisional ex post imbalance price

(a) If *AEMO* has delayed the publication of the *ex post imbalance price* under *rule* 426(1A) it must determine a *provisional ex post imbalance price* for the preceding *gas day* using:

(i) the inputs used to determine the *ex ante market schedule* for that *hub* and *gas day* in accordance with *rule* 415(1); and

(ii) the *market scheduled quantities* specified in the *ex ante market schedule* for that *hub* and *gas day*; and

(iii) any available *STTM facility allocations*; and

(iv) if an *STTM facility allocation* is not available for an *STTM facility*, the quantity determined under clause 7.2.1C(c).

(b) *AEMO* must make available the *provisional ex post imbalance price* to *Trading Participants* by 5½ hours after the beginning of a *gas day*, and must *publish* that *provisional ex post imbalance* price as soon as practicable after that time.

Note: in the event the *ex post imbalance price* is deferred from 5½ to 9½ hours after the beginning of a *gas day*, *AEMO* will determine a *provisional ex post imbalance price*. The *provisional ex post imbalance price* will be used to calculate the cumulative price for tomorrow's *gas day* in accordance with clause 8.1.1 of these Procedures. The *provisional ex post imbalance price* may also be used for prudential monitoring in accordance with clause 11.1 of these Procedures that is, the latest price at the time prudential monitoring is undertaken by *AEMO*, whether that is the *provisional ex post imbalance price* or the *ex post imbalance price*, will be used for prudential monitoring purposes.

7.2.2 MOS step allocations

For the purposes of *rule* 419(2)(c), a *MOS step allocation* for an *STTM pipeline* must contain the following additional information:

(a) the *gas day* to which the *MOS step allocation* relates;

(b) the *identifier* of the *STTM pipeline* to which the *MOS step allocation* relates; and

(c) the *identifier* of the *MOS stack* to which the *MOS step allocation* relates.

7.2.3 Registered facility service allocations

For the purposes of *rule* 420(3)(c), an allocation notice for a *registered facility service* must contain the following additional information:

(a) the *gas day* to which the allocation notice relates;

(b) the *identifier* of the *STTM facility* to which the allocation notice relates; and

(c) the *identifier* of each *registered trading right* that relates to the *registered facility service*.

7.2.4 STTM distribution system allocations

(a) For the purposes of *rule* 422(1), subject to clause 7.2.4(a1) the *STTM distribution system allocation* for an *STTM User* is:

(i) at the *Sydney hub* – the quantity of gas determined by *AEMO*, in accordance with the *Retail Market Procedures* for New South Wales, to have been withdrawn from the *hub* by either:

(A) the *trading right holder* in their capacity as a *user* or self-contracting *user*; or

(B) a *user* or self-contracting *user* who is an associate of the *trading right holder,* where *AEMO* has written authorisation from both parties to use that quantity; or

(ii) at the *Adelaide hub* – the quantity of gas determined by *AEMO*, in accordance with the *Retail Market Procedures* for South Australia, to have been withdrawn from the *STTM distribution system* at that *hub* by either:

(A) the *trading right holder* for that *registered distribution service* in their capacity as a *user* or self-contracting *user*; or

(B) a *user* or self-contracting *user* who is an associate of the *trading right holder,* where *AEMO* has written authorisation from both parties to use that quantity, or

(iii) at the *Brisbane hub*:

(A) in the case of a *deemed STTM distribution system*, the quantity of gas determined by *AEMO* to have been withdrawn from the *hub* by *trading right holders* calculated by reference to the quantities provided by the *STTM facility operator* in accordance with clause 7.2.5; or

(B) for all other *STTM distribution systems,* the quantity of gas determined by *AEMO* to have been withdrawn from the *hub* in accordance with the *Retail Market Procedures* for Queensland by either:

(1) the *trading right holder* in their capacity as a retailer or *self contracting user*; or

(2) a retailer or *self contracting user* who is an associate of the *trading right holder*, where *AEMO* has written authorisation from both parties to use that quantity,

as adjusted by *AEMO* in accordance with paragraph (b).

(a1) If, 4½ hours after the beginning of the *gas day*, *AEMO* is not able to determine the *STTM distribution system allocation* for an *STTM User* at a *hub* for a *gas day* in accordance with clause 7.2.4(a); then *AEMO* must, as soon as practicable:

(i) *publish* a notice of this fact; and

(ii) determine the *STTM distribution system allocation* for each *STTM User* at that *hub* for that *gas day* as if the quantities of gas withdrawn from the *hub* were equal to the quantities that were scheduled to be withdrawn by that *STTM User* in the *ex ante market schedule* for that *gas day.*

(b) For the purposes of *rule* 422(3), *AEMO* must scale a quantity determined under paragraph (a) by multiplying that quantity by a scaling factor calculated as:

(i) the sum of all *STTM facility allocations* for flow to the relevant *hub* on the relevant *gas day*, less the sum of all *STTM facility allocations* for flow from that *hub* on that *gas day*;

(ii) divided by the sum of all *STTM distribution system allocations* at that *hub* for that *gas day*.

(c) For the purposes of *rule* 422(4), *AEMO* must determine an updated *STTM distribution system allocation* for each *gas day* in a *billing period* prior to the date on which *AEMO* must issue a *preliminary statement, final statement* or *revised statement* in accordance with Division 10 of the *Rules*, or the date on which it intends to issue a *revised statement*.

(d) For the purposes of *rule* 422(5), if *AEMO* updates the quantity of gas withdrawn by a *user* or self-contracting *user* in accordance with the relevant *Retail Market Procedures*, *AEMO* must update the *STTM distribution system allocation* for the relevant *registered trading right holder's registered distribution service* as soon as practicable.

(e) In this clause 7.2.4, the terms ***user***, ***retailer*** and ***self contracting user*** have the same meanings as in Part 15A of the *National Gas Rules* for the relevant *retail gas market*.

7.2.5 STTM pipeline operator information

(a) No later than 3½ hours after the beginning of each *gas day,* each *STTM pipeline operator* whose *STTM pipeline* is connected to more than one *STTM distribution system* at a *hub* must provide to *AEMO* the total quantity of gas it deems to have been delivered to each *custody transfer point* where gas passes to an *STTM distribution system* that is not a *deemed STTM distribution system* for the immediately preceding *gas day*

(b) Whenever the *allocation agent* for an *STTM pipeline operator* gives *AEMO* an allocation notice in accordance with *rule* 419(1) or an updated allocation notice in accordance with *rule* 419(4), the *STTM pipeline operator* must, for the relevant *gas day,* provide to *AEMO*:

   (i) an update of the quantities provided under subclause (a); and

   (ii) the quantity or an updated quantity of gas it deems to be withdrawn by each *STTM User* to each *deemed STTM distribution system*.

7.3 Market schedule variations

(aa) For the purposes of rule 423(1), a *market schedule variation* is to be submitted:

   (i) after 6½ hours after the beginning of the immediately preceding *gas day*; and

   (ii) before 5:00pm on the 7th gas day after the *gas day* to which that *market schedule variation* relates.

(a) For the purposes of rule 423(2)(a), information required about the nature and quantity of the proposed *market schedule variation* is:

   (i) the gas day to which the proposed market schedule variation relates;

(ii) the quantity of the proposed *market schedule variation*, which must be a positive value expressed in GJ; and

(iii) whether the quantity of the proposed *market schedule variation* is to increase or decrease the *modified market schedule quantity* of the *originating Participant.*

(b) For the purposes of rule 423(2)(b), the information required about the *originating Participant* is:

(i) the *identifier* of the *originating Participant;*

(ii) whether the proposed *market schedule variation* relates to the *originating Participant* as an:

(A) *STTM Shipper* supplying gas to the *hub*; or

(B) *STTM Shipper* withdrawing gas from the *hub*; or

(C) *STTM User;* and

(iii) where the proposed *market schedule variation* relates to gas:

(A) supplied to the *hub* by the *originating Participant* as an *STTM Shipper*; and

(B) withdrawn from the *hub* by the *receiving Participant* as an *STTM Shipper*,

the *STTM facility* in respect of which the *modified market schedule quantity* of the *originating Participant* is to increase or decrease by the quantity in the proposed *market schedule variation*.

(c) For the purposes of rule 423(2)(c), the information required about the *receiving Participant* is:

(i) the *identifier* of the *receiving Participant*;

(ii) whether the proposed *market schedule variation* relates to the *receiving Participant* as an:

(A) *STTM Shipper* supplying gas to the *hub*; or

(B) *STTM Shipper* withdrawing gas from the *hub*; or

(C) *STTM User;* and

(iii) where the proposed *market schedule variation* relates to gas:

(A) supplied to the *hub* by the *originating STTM Shipper*;

and

(B) withdrawn from the *hub* by the *receiving Participant* as an *STTM Shipper*,

the *STTM facility* in respect of which the *modified market schedule quantity* of the *receiving Participant* is to increase or decrease by the quantity in the proposed *market schedule variation*.

(d) Except in the circumstances described in clause 7.3(c)(iii), AEMO must assume that:

(i) if the proposed *market schedule variation* relates to the *originating Participant* or the *receiving Participant* as an *STTM User*, the *STTM distribution system* in respect of which the *modified market schedule quantity* of the *originating Participant* or the *receiving Participant* is to increase or decrease under the proposed *market schedule variation* is the *STTM distribution system* at the *hub* to which the *STTM facility* specified under clause 7.3(b)(iii) is connected; or

(ii) if:

(A) the proposed *market schedule variation* relates to the *receiving Participant* as an *STTM Shipper* supplying gas to the *hub*; or

(B) the proposed *market schedule variation* relates to both the *originating Participant* and the *receiving Participant* as *STTM Shippers* withdrawing gas from the *hub*,

the *STTM facility* in respect of which the *modified market schedule quantity* of the *receiving Participant* is to increase or decrease under the proposed *market schedule variation* is the *STTM facility* specified under clause 7.3(b)(iii).

(e) For the purposes of rule 423(3), when

(i) both the *originating Participant* and the *receiving Participant* are *STTM Shippers* and the proposed *market schedule variation* relates to:

(A) one *STTM Shipper* supplying gas to the *hub* and the other *STTM Shipper* withdrawing gas from the *hub*, the *STTM Shipper* that is supplying gas to the *hub* must be the *originating STTM Shipper*; or

(B) both *STTM Shippers* supplying gas to the *hub*, the *STTM Shipper* that is to increase its *modified market schedule quantity* for flow to the *hub* must be the *originating STTM Shipper*; and

(C) both *STTM Shippers* withdrawing gas from the *hub*, the *STTM Shipper* that is to increase its *modified market schedule quantity* for flow from the *hub* must be the *originating STTM Shipper*.

(ii) both the *originating Participant* and the *receiving Participant* are *STTM Users*, the *STTM User* that is to increase its *modified market schedule quantity* for flow from the *hub* must be the *originating Participant*.

(iii) the proposed *market schedule variation* relates to an *STTM Shipper* and an *STTM User*, the *STTM Shipper* must be the *originating Participant*.

(f) The *originating Participant* must ensure that both the *originating Participant* and the *receiving Participant* have *registered trading rights* that are consistent with the increase or decrease in their respective *modified market schedule quantities* under the proposed *market schedule variation*.

(g) For the purposes of rule 423(5):

(i) the details to be made available by AEMO to the *receiving Participant* are the details provided for in rule 423(2), which includes those detailed in this clause.

(ii) the *receiving Participant* is to confirm the *proposed market schedule variation* before 5:00pm on the 7th *gas day* after the *gas day* to which that *market schedule variation* relates.

(h) For the purposes of rule 423(6), AEMO must make information regarding the status of a proposed *market schedule variation* available to the *originating Participant* and the *receiving Participant* until 5:00pm on the 7th gas day after the *gas day* to which that *market schedule variation* relates.

7.4 MOS allocation service cost

For the purposes of *rule* 424(5), reasonable evidence provided to *AEMO* by an *STTM pipeline operator* must include, but is not limited to:

(a) the number of *STTM pipelines* operated by that *STTM pipeline operator*;

(b) the number of *STTM Shippers* and *MOS providers* on each *STTM pipeline*;

(c) a breakdown of costs by reference to:

(i) time allocation to tasks or process steps performed exclusively for *MOS allocation services*;

(ii) labour cost rates;

(iii) fixed cost allocations; and

(iv) any other specified costs; and

(d) to the extent that the allocation of *MOS* and *overrun MOS* is performed on behalf of an *STTM pipeline operator* by an *allocation agent*, a breakdown of fees payable by the *STTM pipeline operator* to that *allocation agent* by reference to the matters described in paragraph (c).

7.5 Ranked deviation quantities information

(a) By 4:00 pm on each *gas day AEMO* must, subject to paragraph (b), make available to *Trading Participants* the following information:

(i) whether a *Trading Participant* has a *long deviation quantity* or a *short deviation quantity* for each *STTM facility* and *STTM distribution system* at a *STTM Hub*; and

(ii) where the *deviation quantity* in paragraph (i) is ranked relative to the *deviation quantities* of other *Trading Participants*.

(b) *AEMO* must only:

(i) obtain the information in paragraph (a) from *Trading Participants*, and

(ii) provide the information in paragraph (a) to *Trading Participants*,

who have agreed, in writing, to participate in the information exchange.

(c) *AEMO* must make available to any party, upon request, a list of those *Trading Participants* that are participating in the information exchange.

7.6 Reporting on validation and substitution of data

(a) *AEMO* must prepare a report if information to be provided in accordance with:

(i) *rule* 414, on a *gas day* for the following *gas day*; or

(ii) *rule* 419,

is not provided or fails validation.

(b) The report must include:

(i) a description of the event;

(ii) *AEMO's* assessment of:

(A) the actions taken by *STTM facility operators* and *AEMO* in relation to the event;

(B) the effect of the event on the operation of the *STTM*; and

(iii) any other matter that *AEMO* considers relevant.

(c) *AEMO* must *publish* the report within 30 *business days* of the conclusion of the event.

CHAPTER 8 – ADMINISTERED MARKET STATES

8.1 Cumulative Price Threshold

(a) For the purposes of *rule* 428(1)(b) and 432, the *cumulative price threshold* is exceeded in respect of a *gas day* D if the cumulative price determined under paragraph (b) for *gas day* D exceeds the *cumulative price threshold*.

(b) The cumulative price based on data available on *gas day* d to apply to a *gas day* D=d+1 is Z(d), being the prior *gas day's* cumulative price adjusted to include the price contribution of *gas day* d and to exclude the price contribution of *gas day* d-n, calculated as:

Z(d) = Z(d-1) + A(d) – A(d-n)

where:

(i) Z(d) is the cumulative price based on data available on *gas day* d;

(ii) Z(d-1) is the cumulative price based on data available on *gas day* d-1;

(iii) A(d) is the price contribution determined under paragraph (c) based on data available on *gas day* d, to be added to the cumulative price;

(iv) A(d-n) is the price contribution determined under paragraph (c) based on data available on *gas day* d-n, to be deducted from the cumulative price because it is no longer within the period to be accumulated; and

(v) n is the number of days in the *CPT horizon*.

(c) The price contribution based on data available on *gas day* d, being the value of A(d) in the cumulative price calculation, representing the contribution of prices determined for *gas days* D=d-1, D=d and D=d+1 as known on *gas day* d and which have not already been included in the cumulative price, is calculated as:

A(d) = Cx(d) + Cy(d) + Cz(d)

where:

(i) Cx(d) is the contribution of prices determined for *gas day* D=d+1, calculated as Max(0, HP(d));

(ii) Cy(d) is the contribution of prices determined for *gas day* D=d, calculated as Max(0, HCGP1(d) – Cx(d-1));

(iii) Cz(d) is the contribution of prices determined for *gas day* D=d-1, calculated as:

(A) if DPFlag(d) = 1 for *gas day* D=d-1, then Cz(d) = Max(0, Max(EPP(d), HCGP2(d), MPC(d-1)) – Cy(d-1) – Cx(d-2));

(B) otherwise, Cz(d) = Max(0, Max(EPP(d), HCGP2(d)) - Cy(d-1) – Cx(d-2));

(iv) HP(d) is, subject to paragraph (d), the *ex ante market price* determined on *gas day* d for the *gas day* D=d+1;

(v) HCGP1(d) is the highest priced *contingency gas offer scheduled* for *gas day* D=d as at 5½ hours after the beginning of *gas day* d, but if no *contingency gas offer* has been *scheduled* as at that time then HCGP1(d)=0;

(vi) HCGP2(d) is, subject to paragraph (d), the final *high contingency gas price* determined on *gas day* d for *gas day* D=d-1, but if no *high contingency gas price* has been determined then HCGP2(d)=0;

(vii) EPP(d) is, subject to paragraph (d) and (e), the *ex post imbalance price* determined on *gas day* d for *gas day* D=d-1; and

(viii) MPC(d-1) is the *MPC* applicable to *gas day* D=d-1.

(d) In determining A(d), if the application of the *administered price cap* under *rule* 428 results in a price determined by *AEMO* being lower than it would have been before the application of that price cap, then the uncapped price must be used in the determination of A(d). However, if a price required for the determination of A(d) was determined under the *administered ex post pricing state* or *market administered scheduling state*, then the prices as determined under *rule* 429 or 430 (as applicable) must be used.

Note: There will only be a raw price if the normal process – such as running the SPA – has been executed and completed normally, otherwise *AEMO* is defining a price under *Rules* and hence has no raw price.

(e) In the event that *rule* 426(1A) applies:

(i) a *provisional ex post imbalance price* is to be used for the purposes of defining EPP(d) to determine A(d) for *gas day* D=d+1; and

(ii) the *ex post imbalance price* determined by *AEMO* in accordance with *rule* 426(1A) is to be used for the purposes of determining the cumulative price for *gas day* D=d+2.

Note: If a notice provided by an *STTM facility operator* in accordance with *rule* 419(1) is reviewed in accordance with *rule* 419(2A), a *provisional ex post imbalance price* using default allocations for that *STTM facility* and *gas day* d is to be used for the purposes of determining the cumulative price for *gas day* D=d+1. The *ex post imbalance price* made available to *Trading Participants* by 9½ hours after the beginning of *gas day* d is to be used for the purposes of determining the cumulative price for *gas day* D=d+2.

8.2 Technical or Operational Conditions

8.2.1 General

For the purposes of *rule* 428(1)(c), *AEMO* may determine that technical or operational conditions in any *pipeline*, facility or *STTM distribution system* have materially affected the ability of *Trading Participants* to *supply* or withdraw gas at a *hub*, or to *supply* gas to *end users* in the following circumstances:

(a) *AEMO* is notified that *material involuntary curtailment* has occurred in accordance with clause 8.2.2; or

(b) *AEMO* has determined that a *significant constraint* affects the *hub* in accordance with clause 8.2.3.

8.2.2 Material involuntary curtailment

(a) An *STTM distributor* must notify *AEMO* of any *material involuntary curtailment* of *end users* connected to its *STTM distribution system* for a *gas day* D:

(i) no earlier than the commencement of *gas day* D-1; and

(ii) no later than 1½ hours after the beginning of *gas day* D+1.

(a1) An *STTM pipeline operator* must notify *AEMO* of any *material involuntary curtailment* it implements for a *gas day* D:

(i) no earlier than the commencement of *gas day* D-1; and

(ii) no later than 1½ hours after the beginning of gas day D+1.

Note: Under the *Rules*, if a notice is received under paragraph (a) from an *STTM* distributor or under paragraph (a1) from an *STTM pipeline operator* in time for *AEMO* to make a determination of an *administered price cap state* no later than 6½ hours after the beginning of *gas day* D-1, then the effect of the trigger will be to cap the prices in the *ex ante market schedule* as well as the ex post prices. If the determination is made after that time, the effect of the trigger will be to cap only the ex post prices.

(b) A notice given to *AEMO* under paragraph (a) must include:

(i) the *hub* and *gas day* D to which the notice relates;

(ii) a statement that *material involuntary curtailment* occurred, or the *STTM distributor* or the *STTM pipeline operator* reasonably expects *material involuntary curtailment* to occur (as applicable), on the *gas day* to which the notice relates;

(iii) the time(s) at which *material involuntary curtailment* occurred, or is expected to occur, on *gas day* D; and

(iv) the basis on which *material involuntary curtailment* was, or will be, initiated.

(c) If *AEMO* is notified that *material involuntary curtailment* has occurred, *AEMO* must set the DPFlag(d) to value 1 for the relevant *hub* and *gas day* for the purposes of:

(i) calculating the *cumulative price threshold* under clause 8.1; and

(ii) running settlements for that *gas day* under Chapter 10.

Note: The DPFlag corresponds with an "Administered Deviation Price Cap State". The settlement rules and procedures implement this design feature through settlement equations rather than through a market administered state.

8.2.3 Significant constraint affecting a hub

Note: These provisions apply where a *Trading Participant* has taken an *ex ante market schedule* position but then becomes unable to flow that gas due to a technical issue in the supply chain. The notice described below requires evidence of the problem to be provided.

(a) *AEMO* must decide that a ***significant constraint*** affects a *hub* for a *gas day* D if:

(i) a *Trading Participant* has given a notice to *AEMO* under clause 8.2.4 that an *operational constraint* in a *pipeline*, facility or *STTM distribution system* has affected or will affect the ability of that *Trading Participant* to *supply* or withdraw gas at a *hub*, or to *supply* gas from the *hub* to *end users* on *gas day* D; and

(ii) subject to paragraphs (b) or (c), *AEMO* considers that at least one of the following conditions is satisfied in respect of *gas day* D:

(A) for the *hub* as a whole, the greater of:

(1) the total quantity of gas that cannot be supplied to the *hub* as a result of the notified *operational constraint*; or

(2) the total quantity of gas that cannot be withdrawn from the *hub* as a result of the notified *operational constraint*,

exceeds or will exceed 10% of the total quantity *scheduled* for *supply* to the *hub* by all *Trading Participants* in the most recent *schedule* issued for *gas day* D;

(B) for any one *Trading Participant*, the total quantity of gas that cannot be supplied to the *hub* as a result of the notified *operational constraint* exceeds or will exceed 5TJ and 50% of the quantity *scheduled* for *supply* to the *hub* by that *Trading Participant* in the most recent *schedule* issued for *gas day* D; or

(C) for any one *Trading Participant*, the total quantity of gas that cannot be withdrawn from the *hub* exceeds or will exceed 5TJ and 50% of the quantity *scheduled* for withdrawal from the *hub* by that *Trading Participant* in the most recent *schedule* issued for *gas day* D.

Example: Suppose a *hub* has a *scheduled* flow of 200TJ in the *ex ante market schedule*. A shipper with 80TJ is unable to *supply* all its gas to the *hub*. If that shipper's underdelivery quantity is 8TJ then that shipper alone cannot trigger the state because it has lost only 10% of its flow. However, if the underdelivery is 20TJ, even though it has not hit the 50% individual threshold, it has reached the overall *hub* threshold of 10%, so can trigger the state.

(b) If a notice given by a *Trading Participant* under paragraph 8.2.4 indicates that the *operational constraint* impacts *as available capacity*, *AEMO* may only take a related quantity of gas into account for the purposes of paragraph (a)(ii):

(i) if the *as available capacity* relates to an *STTM pipeline*; and

(ii) if the status of the relevant *STTM pipeline* on the National Gas Services Bulletin Board was red or orange for *gas day* D at the time the notice was given; and

(iii) up to the limit of the quantity that was either:

(A) *scheduled* in the *ex ante market schedule* for that *Trading Participant* on *gas day* D, and for which the relevant *STTM pipeline operator* had accepted a nomination; or

(B) not *scheduled* in the *ex ante market schedule*, for that *Trading Participant* on *gas day* D, but for which the relevant *STTM pipeline operator* had accepted a nomination,

as supported by acceptable evidence in accordance with clause 8.2.5.

(c) If a notice given by a *Trading Participant* under clause 8.2.4 indicates that the *operational constraint* affects the ability of a *producer* to deliver a quantity of gas to an *STTM facility* that was nominated to the *producer* for a date that would have allowed the gas to reach the *hub* on *gas day* D, *AEMO* may only take that quantity of gas into account for the purposes of paragraph (a)(ii) to the extent that:

(i) the relevant quantity of gas would have been supplied to the *hub* on *gas day* D using *firm capacity* in an *STTM pipeline*;

(ii) on the same *gas day* on which the *producer* notified the *Trading Participant* of its rejection of the nomination, the *Trading Participant* notified *AEMO* of that rejection; and

Note: This notice will be required prior to, and in addition to, the notice required by the time in clause 8.2.6. This requires an *STTM Shipper* to notify *AEMO* on the day that the nomination was rejected if its *supply* issue is to be considered in triggering a state. The advantage of this is that it ensures early notification of an issue to the market and reflects the core issue – there was a problem at the *supply* source. While this might be considered onerous, it is difficult to justify an *STTM Shipper* being able to delay notification of such an event until the gas would have arrived at the *hub* (had it flowed).

(iii) the notice given to *AEMO* under clause 8.2.4 is supported by acceptable evidence in accordance with clause 8.2.5 that a nomination for that quantity was made to the *producer* but was rejected as a result of the *operational constraint*.

8.2.4 Notice of operational constraint

(a) A *Trading Participant* may notify *AEMO* if it considers that an *operational constraint* affects or will affect a *hub* on a *gas day* D as described in clause 8.2.3(a)(i). The *Trading Participant* must give the notice by the time specified in clause 8.2.6, including the following information:

(i) the *hub* and *gas day* D to which the notice relates;

(ii) a description of the *operational constraint*;

(iii) the quantity of gas in GJ which, as a result of the *operational constraint*, the *Trading Participant*:

(A) can no longer *supply* to the *hub*, using *firm capacity* and separately (if applicable) *as available capacity*; and/or

(B) can no longer withdraw from the *hub*, using *firm capacity* and separately (if applicable) *as available capacity*,

on *gas day* D to which the notice relates, together with acceptable evidence under clause 8.2.5; and

(b) The *Trading Participant* must:

(i) ensure that the information in the notice is accurate; and

(ii) take all measures within its reasonable control to mitigate the effects of the *operational constraint*.

8.2.5 Acceptable evidence

For the purpose of clause 8.2.4, acceptable evidence includes:

(a) for an *operational constraint* affecting gas production, written confirmation from the *producer* indicating, for the *gas day* on which the gas was to be supplied by the *producer*, the quantity of gas that was nominated by the *Trading Participant* but rejected by the *producer*; or

(a1) for an *operational constraint* affecting a *deemed STTM distribution system*, written confirmation from the applicable *STTM pipeline operator* that an *operational constraint* has arisen, including details of the expected impact on *Trading Participants* and the *gas day* on which the *operational constraint* is expected to be rectified; or

(b) for any other *operational constraint,* written confirmation from the applicable facility operator or *STTM distributor* that an *operational constraint* has arisen, including details of the expected impact on the *Trading Participant* and the *gas day* on which the *operational constraint* is expected to be rectified.

8.2.6 Time for notice

A notice under clause 8.2.4 in respect of a *gas day* D must be given to *AEMO*:

(a) in the case of the first *gas day* for which an *operational constraint* affects the *hub*:

(i) no earlier than 6½ hours after the beginning of *gas day* D-1; and

(ii) no later than 1½ hours after the beginning of *gas day* D+1; and

(b) in the case of any subsequent consecutive *gas day* for which an *operational constraint* affects the *hub* – no earlier than ½ hour prior to the beginning of *gas day* D-1 and no later than 2½ hours after the beginning of *gas day* D-1.

8.3 Major and Minor Retailer of Last Resort Events

8.3.1 Determination of market share

Where a *retailer of last resort* assumes responsibility for customers of one or more *exiting retailers*, *AEMO* must calculate the aggregate market share of the *exiting retailer*s in respect of a *hub* by following the steps below, using data for the most recent month for which preliminary settlement data is available.

(a) Step 1: *AEMO* calculates, for each *STTM User* at the *hub*, the total *allocated quantity* of gas withdrawn from the *hub* during the month, being the sum of gas allocated as withdrawn by that *STTM User* in *STTM distribution system allocations.*

(b) Step 2: *AEMO* calculates the market share for each *exiting retailer* (as a percentage) by dividing the value determined for that *exiting retailer* in step 1 by the sum of the values determined in step 1 for all *STTM Users* at the same *hub*, and multiplying by 100.

8.3.2 Level of retailer of last resort event

(a) For the purposes of *rule* 428(1)(d), *AEMO* must determine that a ***minor retailer of last resort event*** has occurred where it calculates that the aggregate market share of the *exiting retailers* at the relevant *hub* under clause 8.3.1(b) is greater than or equal to 3% but less than 6%.

(b) For the purposes of *rule*s 430(1)(b)(i) and 431(1)(a), *AEMO* must determine that a ***major retailer of last resort event*** has occurred where it calculates that the aggregate market share of the *exiting retailer*s under clause 8.3.1(b) is greater than or equal to 6%.

8.4 Market Schedule Quantities in Market Administered Scheduling State and Market Administered Settlement State

8.4.1 Principles for determining market schedule quantities

(a) The *market schedule quantities* referred to in *rule* 430(2)(a)(iv) and 431(2)(b)(iv) must be revised for each run of the settlement system (whether for prudential monitoring, *preliminary statements, final statements* or *revised statements*) for which revised *STTM facility allocation* data is available.

(b) For each settlement run, *AEMO* must use available data so as to:

(i) produce an *ex ante market schedule* that results in no *deviation payments* or *deviation charges* being applied to a *Trading Participant* for the relevant *gas day*; or

(ii) if *AEMO* is unable to produce this schedule, determine *ad hoc payments* or *ad hoc charges* for a *Trading Participant* so that the effective price per GJ of deviation is equal to the *ex ante market price*.

(c) If *AEMO* is required to determine a *registered facility service allocation* under *rule* 420(5) then, for the purpose of this clause 8.4, *AEMO* must assume that all quantities of gas supplied or withdrawn in respect of a *registered facility service* were supplied or withdrawn by the *contract holder* for that *registered facility service*.

8.4.2 Matters to be determined

For the purposes of determining *market schedule quantities* under *rule* 430(2)(a)(iv) or 431(2)(b)(iv), *AEMO* must first determine the following matters in respect of each *gas day* for which a *market administered scheduling state* or a *market administered settlement state* applies:

(a) the sum of all *market schedule quantities* for the *registered trading rights* of each *Trading Participant* for the *supply* of gas to the *hub* on an *STTM facility*, calculated as:

(i) the total *allocated quantities* across all *registered trading rights* of that *Trading Participant* for *supply* to the *hub* on that *STTM facility*;

(ii) less quantities *scheduled* under *contingency gas offers* by that *Trading Participant* using that *STTM facility*;

(iii) plus quantities *scheduled* under *contingency gas bids* by that *Trading Participant* using that *STTM facility*;

(iv) less quantities of *MOS gas* allocated to the *Trading Participant* for that *STTM facility* that increase the total quantity of gas supplied to the *hub* by that *Trading Participant*;

(v) plus quantities of *MOS gas* allocated to the *Trading Participant* for that *STTM facility* that decrease the total quantity of gas supplied to the hub by that *Trading Participant*;

(vi) less the quantity of gas associated with *market schedule variations* that increase the amount taken to have been supplied to the *hub* by the *Trading Participant* on that *STTM facility*;

(vii) plus the quantity of gas associated with *market schedule variations* that decrease the amount taken to have been supplied to the *hub* by the *Trading Participant* on that *STTM facility*;

Example: If a shipper is allocated 10TJ of flow to the *hub* on a *pipeline*, but decreased flow to the *hub* by 2TJ due to *contingency gas bids* being *scheduled*, provided 1TJ of *MOS increase offer*, and used an MSV for decreased flow to the *hub* to reflect a reduction of 3TJ in its *pipeline schedule* then the value to be determined is: 10-(0)+(2)–(1)+(0)–(0)+(3) =14TJ. That is, the *ex ante market schedule* for that shipper on that *pipeline* is deemed to be 14TJ of flow to the *hub*. After decreasing by 2TJ for *contingency gas*, increasing it by 1TJ for *MOS*, and decreasing it by 3TJ for MSVs the settlement equations will produce a *modified market schedule* of 10TJ. This matches the allocation so there is no deviation.

(b) the sum of all *market schedule quantities* for the *registered trading rights* of each *Trading Participant* for the withdrawal of gas from the *hub* on an *STTM facility*, calculated as:

(i) the total *allocated quantities* across all *registered trading rights* of that *Trading Participant* for withdrawal from the *hub* on that *STTM facility*;

(ii) plus quantities *scheduled* under *contingency gas offers* by that *Trading Participant* using that *STTM facility*;

(iii) less quantities *scheduled* under *contingency gas bids* by that *Trading Participant* using that *STTM facility*;

(iv) plus quantities of *MOS gas* allocated to the *Trading Participant* for that *STTM facility* that increase the total quantity of gas supplied to the *hub* by that *Trading Participant*;

(v) less quantities of *MOS gas* allocated to the *Trading Participant* for that *STTM facility* that decrease the total quantity of gas supplied to the *hub* by that *Trading Participant*;

(vi) less the quantity of gas associated with *market schedule variations* that increase the amount taken to have been withdrawn from the *hub* by the *Trading Participant* on that *STTM facility*;

(vii) plus the quantity of gas associated with *market schedule variations* that decrease the amount taken to have been withdrawn from the *hub* by the *Trading Participant* on that *STTM facility*; and

Example: If a shipper is allocated 10TJ of flow from the *hub* on a *pipeline*, but increased flow from the *hub* by 2TJ due to *contingency gas bids* being *scheduled*, provided 1TJ of *MOS increase offer* (by reducing its offtake), and used an MSV for decreased flow from the *hub* to reflect a reduction of 3TJ in its *pipeline schedule* then the value to be determined is: 10+(0)-(2)+(1)-(0)-(0)+(3)=12TJ. That is, the *ex ante market schedule* for that shipper on that *pipeline* is deemed to be 12TJ of flow from the *hub*. After increasing off-take by 2TJ through contingency gas, decreasing flow by 1TJ to *supply MOS* to the *hub*, and decreasing it by 3TJ for MSVs the settlement equations will produce a modified market schedule of 10TJ or flow from the *hub*. This matches the allocation so there is no deviation.

(c) the sum of all *market schedule quantities* for the *registered trading rights* of each *Trading Participant* for the withdrawal of gas from the *hub* using a *registered distribution service*, calculated as:

(i) the total *allocated quantities* across all *registered trading rights* associated with the *registered distribution service*;

(ii) plus quantities *scheduled* under *contingency gas offers* by that *Trading Participant* using the relevant *STTM distribution system*;

(iii) less quantities *scheduled* under *contingency gas bids* by that *Trading Participant* using the relevant *STTM distribution system*;

(iv) less the quantity of gas associated with *market schedule variations* that increase the amount taken to have been withdrawn from the *hub* by the *Trading Participant* on the *STTM distribution system*;

(v) plus the quantity of gas associated with *market schedule variations* that decrease the amount taken to have been withdrawn from the *hub* by the *Trading Participant* on the *STTM distribution system*.

8.4.3 Market schedule quantities

(a) Subject to paragraphs (b) and (c), *AEMO* must determine the *market schedule quantity* for each *registered trading right* of a *Trading*

Participant for a *gas day* D for which a *market administered scheduling state* or *market administered settlement state* applies by (as applicable):

(i) allocating the value determined under clauses 8.4.2(a) or (b) for *gas day* D to a *registered trading right* of the *Trading Participant* that relates to an *STTM facility service* for the relevant *STTM facility* and flow direction; and

(ii) allocating the value determined under clause 8.4.2(c) for *gas day* D to a *registered trading right* of the *Trading Participant* that relates to the *hub*.

(b) *AEMO* may allocate a value under paragraphs (a)(i) or (ii) to any one or more relevant *registered trading rights* in any proportions determined by *AEMO*.

(c) If a value determined under clauses 8.4.2(a), (b) or (c) is negative, the *market schedule quantity* for each relevant *registered trading right* is zero.

8.4.4 Ad hoc payments and charges

If a value determined under clauses 8.4.2(a), (b) or (c) for a *Trading Participant* is negative, *AEMO* must determine the *ad hoc payment* (AHP(p,d)) or *ad hoc charge* (AHC(p,d)) for that *Trading Participant* and *gas day*, calculated as:

(a) the *deviation charge* for that *Trading Participant* for that *gas day* (DevC(p,d)) calculated in accordance with clause10.8.11(f); less

(b) the *deviation payment* for that *Trading Participant* for that *gas day* (DevP(p,d)) calculated in accordance with clause 10.8.11(e); plus

(c) the *ex ante market price* for that *hub* and *gas day* (HP(d)) multiplied by:

(i) any negative value determined in clause 8.4.2(a); less

(ii) any negative value determined in clause 8.4.2(b); less

(iii) any negative value determined in clause 8.4.2(c),

and the result of that calculation will be an *ad hoc payment* if it is a positive amount and an *ad hoc charge* if it is a negative amount.

CHAPTER 9 – CONTINGENCY GAS

9.1 Contingency Gas Offers and Bids

9.1.1 Contingency gas offers

(a) For the purposes of *rule* 435(3)(b), a *contingency gas offer* must specify:

(i) the *identifier* of the *Trading Participant* submitting the *contingency gas offer*; and

(ii) the *gas day* to which the *contingency gas offer* relates; and

(iii) either:

(A) the *identifier* of the *STTM distribution system*; or

(B) the *identifier* of the *STTM facility* and the direction of flow,

to which the *contingency gas offer* relates; and

(iv) at least one and up to ten *price steps*.

(b) Each *price step* must specify:

(i) a single price, expressed in $/GJ to four decimal places, greater than or equal to *MMP* and less than or equal to *MPC*; and

(ii) the maximum quantity of *contingency gas* that the *Trading Participant* is willing to provide to the *hub* at the price specified under subparagraph (i), expressed in whole GJ.

(c) If the price in a *price step* (referred to in this paragraph as the ***higher price step***) is greater than the price in any other *price step* in the *contingency gas offer*, then the quantity in the higher price step must be greater than the quantity in that other *price step*.

***Note*:** The purpose of paragraphs (c) and (d) is to ensure that each *price step* represents a cumulative quantity of gas, and that prices increase with increasing *price step* quantities.

(d) A *price step* must not have the same price as any other *price step* in the *contingency gas offer*.

(e) For the purposes of *rule* 435(5), the quantity of gas specified in a *contingency gas offer* for a *gas day* should not exceed:

(i) for an *STTM Shipper* offering to increase the *supply* of gas to the *hub* from an *STTM facility*:

(A) the aggregate of its *capacity limits* under all *registered trading rights* for flow to the *hub* from the relevant *STTM facility*;

(B) less any gas it is *scheduled* to *supply* to the *hub* from the relevant *STTM facility* in the *ex ante market schedule* for that *gas day*;

(C) plus any additional gas it reasonably expects to be able to *supply* to the *hub* from the relevant *STTM facility* on that *gas day*;

(ii) for an *STTM Shipper* offering to decrease the withdrawal of gas from the *hub* on an *STTM pipeline*:

(A) the quantity of gas it is *scheduled* to withdraw from the *hub* on the relevant *STTM pipeline* in the *ex ante market schedule* for that *gas day*;

(B) plus any additional quantity of gas it reasonably expects to withdraw from the *hub* on the relevant *STTM pipeline* on the *gas day*; or

(iii) for an *STTM User* offering to decrease the withdrawal of gas from the *hub* into the *STTM distribution system*, the maximum reduction in the quantity of gas consumption that it reasonably expects to be achieved by the *STTM User* or its interruptible customers within the *gas day*.

9.1.2 Contingency gas bids

(a) For the purposes of *rule* 436(3)(b), a *contingency gas bid* must specify:

(i) the *identifier* of the *Trading Participant* submitting the *contingency gas bid*; and

(ii) the *gas day* to which the *contingency gas bid* relates; and

(iii) either:

(A) the *identifier* of the *STTM distribution system*; or

(B) the *identifier* of the *STTM facility* and the direction of flow,

to which the *contingency gas bid* relates; and

(iv) at least one and up to ten *price steps*.

(b) Each *price step* must specify:

(i) a single price, expressed in $/GJ to four decimal places, greater than or equal to *MMP* and less than or equal to *MPC*; and

(ii) the maximum quantity of *contingency gas* that the *Trading Participant* is willing to provide to the *hub* at the price specified under subparagraph (i), expressed in whole GJ.

(c) If the price in a *price step* (referred to in this paragraph as the ***higher price step***) is greater than the price in any other *price step* in the *contingency gas bid*, then the quantity in the higher price step must be less than the quantity in that other *price step*.

Note: The purpose of paragraphs (c) and (d) is to ensure that each *price step* represents a cumulative quantity of gas, and that prices decrease with increasing *price step* quantities.

(d) A *price step* must not have the same price as any other *price step* in the *contingency gas bid*.

(e) For the purposes of *rule* 436(5), the quantity of gas specified in a *contingency gas bid* for a *gas day* should not exceed:

(i) for an *STTM Shipper* bidding to decrease the *supply* of gas to the *hub* from an *STTM facility*:

(A) the quantity of gas it is *scheduled* to *supply* to the *hub* from the relevant *STTM facility* in the *ex ante market schedule* for that *gas day*;

(B) plus any additional quantity of gas it reasonably expects to *supply* to the *hub* from the relevant *STTM facility* on the *gas day*; or

(ii) for an *STTM Shipper* bidding to increase the withdrawal of gas from the *hub* on an *STTM pipeline*:

(A) the aggregate of its *capacity limits* under all *registered trading rights* for flow from the *hub* on the relevant *STTM pipeline*;

(B) less any gas it is *scheduled* to withdraw from the *hub* on the relevant *STTM pipeline* in the *ex ante market schedule* for that *gas day*;

(C) plus any additional gas it reasonably expects to be able to withdraw from the *hub* on the relevant *STTM pipeline* on that *gas day*;

(iii) for an *STTM User* bidding to increase the withdrawal of gas from the *hub* into the *STTM distribution system*:

(A) the aggregate of its *capacity limits* under all *registered trading rights* for the withdrawal of gas from the *hub*;

(B) less any gas it is *scheduled* to withdraw from the *hub* in the *ex ante market schedule* for that *gas day*;

(C) plus any additional gas it reasonably expects to be able to withdraw from the *hub* on that *gas day*.

9.1.3 Publication of contingency gas offers and contingency gas bids

(a) For the purposes of *rule* 435(8), *AEMO* must make the following information for each *contingency gas offer* submitted for a *gas day* available to each *Trading Participant* after the end of that *gas day* and before 11:00 am on the next *gas day*:

(i) the identity of the relevant *Trading Participant*; and

(ii) the *hub* and the *STTM distribution system* or *STTM facility* and flow direction to which the *contingency gas offer* relates; and

(iii) the prices and quantities in each *price step*.

(b) For the purposes of *rule* 436(8), *AEMO* must make the following information for each *contingency gas bid* submitted for a *gas day* available to each *Trading Participant* after the end of that *gas day* and before 11:00 am on the next *gas day*:

(i) the identity of the relevant *Trading Participant*; and

(ii) the *hub* and the *STTM distribution system* or *STTM facility* and flow direction to which the *contingency gas bid* relates; and

(iii) the prices and quantities in each *price step*.

(c) If *AEMO* is unable to make the information specified in paragraphs (a) and (b) available to each *Trading Participant* by 11:00 am on the next *gas day*, *AEMO* must do so as soon as practicable.

(d) *AEMO* must *publish* the information specified in paragraphs (a) and (b) as soon as practicable after that information is provided to *Trading Participants*.

9.2 Contingency Gas Benchmark Information

9.2.1 Benchmark information for STTM facilities

(a) The benchmark information to be provided to *AEMO* by an *STTM pipeline operator* for *contingency gas* purposes under *rule* 376(1)(j) is the *linepack range* for that *STTM pipeline*, being the minimum and maximum quantity of *linepack* which the *STTM pipeline operator* considers, after consultation with the *STTM distributor* at the relevant *hub*, is required to ensure the safe and reliable flow of gas through that *STTM pipeline*, taking into account:

(i) the contractual entitlements of each *user* of the *STTM pipeline* to capacity in that *STTM pipeline*;

(ii) the *STTM pipeline operator's* forecasts of the quantities of gas likely to be injected into and withdrawn from the *STTM pipeline*;

(iii) the operational requirements for the *STTM pipeline*;

(iv) the time required for *Trading Participants* that have submitted *contingency gas offers* or *contingency gas bids* to provide that *contingency gas*;

(v) the time required to curtail withdrawals of gas from the *STTM pipeline*;

(vi) the time required by any *STTM distributor* to curtail withdrawals of gas from an *STTM distribution system* that is supplied with gas from the *STTM pipeline*; and

(vii) the acceptable pressure range for the *custody transfer points* of the *STTM distribution system* that are supplied with gas from the *STTM pipeline*; and

(viii) the ability of the *STTM pipeline* to deliver gas to the *hub*.

(b) The benchmark information to be provided to *AEMO* by an *STTM facility operator* in respect of an *STTM storage facility* or *STTM production facility* for *contingency gas* purposes under *rule* 376(1)(j) is the daily delivery capacity to deliver gas to the *hub* from that *STTM facility,* as determined by that *STTM facility operator* after consultation with the *STTM distributor* at the relevant *hub*.

9.2.2 Benchmark information for STTM distribution systems

(a) The benchmark information to be provided to *AEMO* by an *STTM distributor* for *contingency gas* purposes under *rule* 376(2)(f) is:

(i) the acceptable pressure range for the *custody transfer points* of the *STTM distribution system*; and

(ii) the requirements (if any) for minimum and maximum flows for the *custody transfer points* of the *STTM distribution system*; and

(iii) the range of times required by the *STTM distributor* to curtail withdrawals of gas from the *STTM distribution system*,

as determined by that *STTM distributor* after consultation with all *STTM facility operators* at the relevant *hub*.

(b) This clause does not apply to *deemed STTM distributors*.

9.2.3 Updating benchmark information

For the purposes of *rule* 378(1)(b), an *STTM facility operator* or *STTM distributor* must provide updated benchmark information to *AEMO*:

(a) on 15 May of each year, or if that day is not a *business day*, the first *business day* following that day; and

(b) on 15 October of each year, or if that day is not a *business day*, the first *business day* following that day.

9.3 Contingency Gas Trigger Events

9.3.1 Information about contingency gas trigger events

(a) As soon as practicable after a request by *AEMO* under *rule* 440(2)(b), a *Trading Participant*, *STTM distributor* or *STTM facility operator* must provide all information available to it regarding:

(i) the type of *contingency gas trigger event* that has occurred; and

(ii) any *hub*, *STTM facility* and/or *STTM distribution system* that is affected by a *contingency gas trigger event*.

(b) A person required to provide information under paragraph (a) must use reasonable endeavours to do so within any time specified by *AEMO* in its request.

9.3.2 Notification and communication

(a) A notice *published* by *AEMO* under *rule* 441(1) regarding a *contingency gas trigger event* must:

(i) specify whether *AEMO* was notified of the *contingency gas trigger event* under *rule* 440(2)(a), or whether AEMO considers that the contingency gas trigger event has occurred as contemplated in *rule* 441(1)(b); and

(ii) specify the date and time at which the notification was received or *AEMO* decided that the *contingency gas trigger event* had occurred; and

(iii) identify the relevant *contingency gas trigger event*; and

(iv) include any information provided to *AEMO* under clause 9.3.1(a)(ii).

(b) *AEMO* will chair the *CG assessment conference* convened in accordance with *rule* 441(1)(d).

(c) *AEMO* must convene an additional *CG assessment conference* prior to updating a *contingency gas requirement* in accordance with *rule* 444(4).

9.3.3 Notice before material involuntary curtailment

For the purposes of *rule* 442(5), an *STTM distributor* or an *STTM pipeline operator* must notify *AEMO* before commencing *material involuntary curtailment* in respect of the *hub* to which the *contingency gas trigger event* relates.

9.3.4 Determination of contingency gas requirement

(a) For the purposes of *rule* 444(3)(b), no other details are specified.

(b) For the purposes of *rule* 444(4)(b), if *AEMO* receives a notice from an *STTM distributor* or an *STTM pipeline operator* under clause 9.3.3, *AEMO* must determine under *rule* 444(1) that *contingency gas* is no longer needed at the relevant *hub*.

9.4 Calling and Scheduling Contingency Gas

9.4.1 Confirmation of availability

(a) For the purpose of *rule* 445, prior to *scheduling contingency gas*, *AEMO* must determine the last time by which it can receive confirmation of availability from *Trading Participants*, taking into account the time at which *contingency gas* is required.

(b) If *AEMO* has not completed the confirmation process under this clause by the time determined in paragraph (a), it may commence *scheduling contingency gas* using the quantities that it has confirmed at that time.

(c) If the *contingency gas requirement* includes:

(i) a requirement for increased net *supply* at the *hub* then *AEMO* must produce a provisional *contingency gas offer stack* from the *price steps* of *contingency gas offers* for the applicable *hub*, in order of increasing price; or

(ii) a requirement for decreased net *supply* at the *hub* then *AEMO* must produce a provisional *contingency gas bid stack* from the *price steps* of *contingency gas bids* for the applicable *hub* in order of decreasing price.

(d) In producing the provisional *contingency gas offer stack* or provisional *contingency gas bid stack*, if there is more than one *price step* with the same price, then *AEMO* may place those tied *price steps* in any order.

(e) If the *STTM facility* or *STTM distribution system* indicated in a *contingency gas offer* or *contingency gas bid* is not consistent with the location for the *contingency gas requirement*, then *AEMO* must set the availability of the *price steps* of that *contingency gas offer* or *contingency gas bid* to zero in the relevant provisional *contingency gas stack.*

(f) Subject to paragraph (b), *AEMO* must contact the *Trading Participants* in the provisional *contingency gas offer stack* and/or provisional *contingency gas bid stack*, except those *Trading Participants* whose *price steps* have been set to zero availability under paragraph (e), using the contact details provided under *rule* 434 and request confirmation of:

(i) the total quantity of *contingency gas* that can be provided by the time specified in the *contingency gas requirement* (whether less than, equal to, or greater than the total quantity specified in the applicable *contingency gas offer* or *contingency gas bid*);

(ii) the time at which any additional *contingency gas* would be available and the quantity of gas available at that time, and

(iii) for an *STTM User*, the location of any customer facilities that would be used to make *contingency gas* available,

by the time and in the manner specified by *AEMO* in its request.

(fa) A *Trading Participant* may, instead of confirming availability for its *contingency gas offer* or contingency gas *bid* as a whole, confirm the matters in paragraph (f) in respect of each of the individual *price steps*, provided that:

(i) the *Trading Participant* may only confirm a greater quantity of *contingency gas* for the highest-priced *price step* in its *contingency gas offer* or the lowest-priced *price step* in its *contingency gas bid*;

(ii) the Trading Participant may only confirm a lesser quantity of *contingency gas* (including zero) for a *price step* associated with a facility that was registered under paragraph (g) at least 5 *business days* prior to the date of confirmation; and

(iii) *price steps* associated with registered facilities must be consistent with the relevant information provided under paragraph (g).

(g) A *Trading Participant* may register facilities for the purposes of confirming individual *price steps* by giving *AEMO* the following information:

(i) (for an *STTM Shipper*) a description of each *STTM facility* and any other gas production facility it wishes to associate with a *price step*;

(ii) (for an *STTM User*) a description of each customer facility it wishes to associate with a *price step*;

(iii) the price to be specified in each *price step* associated with each facility;

(iv) the maximum and minimum quantities of *contingency gas* that could be provided by each facility;

(v) the maximum ramp rate for each facility; and

(vi) any other information reasonably requested by *AEMO* for the purposes of associating *price steps* with specified facilities.

(h) Subject to paragraph (i) if the total quantity of *contingency gas* that a *Trading Participant* confirms can be provided by the time specified in the *contingency gas requirement* is:

(i) less than the quantity specified in that *Trading Participant's contingency gas offer*, *AEMO* must set the availability of that *Trading Participant's price steps* in the relevant provisional *contingency gas offer stack* by reducing the quantities in *price steps* in order of decreasing price so that the total quantity across all *price steps* equals the reduced quantity available;

Note: A reduced quantity includes zero availability in the required timeframe, in which case the whole offer will be marked as unavailable and will not be *scheduled*.

(ii) greater than the quantity specified in that *Trading Participant's contingency gas offer*, *AEMO* must set the availability of that *Trading Participant*'s highest priced *price step* in the relevant provisional *contingency gas offer stack* so that the total quantity across all *price steps* equals the increased quantity available;

(iii) less than the quantity specified in that *Trading Participant's contingency gas bid*, *AEMO* must set the availability of that *Trading Participant's price steps* in the relevant provisional *contingency gas bid stack* by reducing the quantities in *price steps* in order of increasing price so that the total across all *price steps* equals the reduced quantity available; or

(iv) greater than the quantity specified in that *Trading Participant's contingency gas bid*, *AEMO* must set the availability of that *Trading Participant*'s lowest priced *price step* in the relevant provisional *contingency gas bid stack* so that the total across all *price steps* equals the increased quantity available.

(i) If the *Trading Participant* has confirmed individual *price steps* under paragraph (fa), *AEMO* must set the availability of each *price step* in accordance with that confirmation.

9.4.2 Scheduling contingency gas

(a) For the purposes of *rule* 446(1):

(i) the *contingency gas offer stack* is the provisional *contingency gas offer stack* created in accordance with clause 9.4.1, excluding any *price steps* with zero availability; and

(ii) the *contingency gas bid stack* is the provisional *contingency gas bid stack* created in accordance with clause 9.4.1, excluding any *price steps* with zero availability,

as at the time at which *AEMO schedules contingency gas* for the relevant *gas day*.

(b) For the purpose of *rule* 446(2)(a), *AEMO* must *schedule contingency gas* in accordance with clauses 9.4.2(c) to (f).

(c) Subject to paragraph (e), if the *contingency gas requirement* includes a requirement for increased net *supply* at the *hub*, *AEMO* must *schedule price steps*, in whole or in part, from the *contingency gas offer* stack, in increasing order of price, until:

(i) the total quantity *scheduled* equals the quantity required; or

(ii) all of the available *price steps* in the stack have been *scheduled*.

(d) Subject to paragraph (e), if the *contingency gas requirement* includes a requirement for decreased net *supply* at the *hub*, *AEMO* must *schedule price steps*, in whole or in part, from the *contingency gas bid stack*, in decreasing order of price, until:

(i) the total quantity *scheduled* equals the quantity required; or

(ii) all of the available *price steps* in the stack have been *scheduled*.

(e) If two or more *price steps* in a *contingency gas offer stack* or *contingency gas bid stack* specify the same price, *AEMO* must *schedule* those *price steps* in proportion to the quantity confirmed as available for each *price step*.

(f) Subject to paragraph (g), where *AEMO* revises the *contingency gas requirement* for a *gas day*, *contingency gas offer price steps* and *contingency gas bid price steps* already *scheduled* must remain *scheduled*.

Note: This paragraph is required so that, if a low cost *contingency gas* provider is not able to provide gas in the time needed under the initial *contingency gas requirement*, and so a higher cost, but quicker responding *contingency gas* provider is *scheduled* instead, the low cost *contingency gas* provider is not able to “bump” the previously *scheduled* high cost provider if the *contingency gas requirement* is revised at a later stage.

(g) In the circumstances contemplated in *rule* 444(5), *AEMO* may contact *Trading Participants* for the purpose of requesting agreement not to provide *contingency gas* as *scheduled* and, if *AEMO* does so:

(i) in relation to a requirement to increase net *supply* to the *hub*, *AEMO* must contact relevant *Trading Participants scheduled* in decreasing order of their *scheduled price steps*;

(ii) in relation to a requirement to decrease net *supply* to the *hub*, *AEMO* must contact the *Trading Participants* previously *scheduled* in increasing order of their *scheduled price steps*;

(iii) no *Trading Participant* is obliged to agree to revise its *scheduled* quantity of *contingency gas*; and

(iv) if that *Trading Participant* agrees to revise its *scheduled* quantity, it is not entitled to claim or receive any compensation under Division 9 of the *Rules* as a result of that revision.

Note: This might occur if the quantity of *contingency gas* required is reduced before voluntary curtailment occurs, and the *Trading Participant* would rather continue to withdraw gas than receive the payment for providing *contingency gas*.

9.5 Evidence of Delivery of Contingency Gas

9.5.1 Requirement of evidence

(a) For the purposes of rule 449(3), a *Trading Participant* must provide reasonable evidence, in accordance with the applicable provisions of this clause 9.5, of:

(i) the quantity of *contingency gas* provided by that *Trading Participant* on a *gas day*;

(ii) the location at which it was provided; and

(iii) the period of time over which it was provided.

(b) Evidence must be provided to AEMO no later than 40 *business days* after the end of the relevant *gas day*.

9.5.2 Demand side contingency gas

(a) For a *scheduled contingency gas offer* or *contingency gas bid* by an *STTM User*, the *STTM User* must provide evidence of:

(i) a reduction or increase in gas consumption at one or more identified customer facilities;

(ii) the initiation of the reduction or increase by an instruction issued by the *STTM User*;

(iii) the start and end time of the reduction or increase, including any period of ramping down or up; and

(iv) the quantity of gas that would ordinarily have been consumed or injected between those times.

(b) Examples of the evidence that could be provided in relation to the matters in paragraph (a) include (as applicable):

(i) metering data for the consumption of gas;

(ii) metering data for any alternative fuel used during a reduction in gas consumption and conversion factors to derive gas equivalent usage rates;

(iii) output or production data for the facility and conversion factors correlating with gas consumption; and

(iv) historical metering or production data sufficient to establish a pattern of hourly gas consumption.

9.5.3 Supply side contingency gas

(a) For a *scheduled contingency gas offer* or *contingency gas bid* by an *STTM Shipper*, the *STTM Shipper* must provide evidence of:

(i) a reduction or increase in gas delivered to or withdrawn from the *hub* by that *STTM Shipper* using an identified *STTM facility*;

(ii) the initiation of the reduction or increase by the *STTM Shipper*;

(iii) the start and end time of the reduction or increase, including any period of ramping down or up; and

(iv) the quantity of gas that would have been delivered or withdrawn in the absence of that reduction or increase.

(b) Examples of the evidence that could be provided in relation to the matters in paragraph (a) include (as applicable):

(i) hourly gas flow and pressure data;

(ii) steps taken by the *STTM facility* operator to reduce or increase gas flow;

(iii) renominations by the *STTM Shipper* and confirmation of acceptance by the *STTM facility* operator.

9.5.4 Pre-approval of evidence methodologies

(a) A *Trading Participant* may apply to *AEMO* for pre-approval of a methodology to be used in evidence of the quantity of *contingency gas* provided on any *gas day* using a specified facility or type of facility and under given supply, demand or production conditions.

(b) Within 20 *business days* of receiving an application under paragraph (a), *AEMO* must either:

(i) approve or reject the proposed methodology; or

(ii) request the *Trading Participant* to provide further information as reasonably required to enable *AEMO* to assess the proposed methodology.

(c) If *AEMO* has requested further information, *AEMO* must either approve or reject the proposed methodology within a further 20 *business days* from the date (or the latest date) on which AEMO receives all the requested information.

(d) If *AEMO* rejects a proposed methodology, it must give the *Trading Participant* reasons for its decision.

(e) *AEMO's* approval of a proposed methodology indicates that *AEMO* accepts that methodology as a legitimate means of establishing the quantity of *contingency gas* provided, but:

(i) does not imply that any particular value or assumption in that methodology, or the outcome of its application, is conclusive evidence of that quantity for any given *gas day*; and

(ii) does not prevent *AEMO* from requesting further evidence to establish that quantity.

CHAPTER 10 - SETTLEMENT

10.1 Settlement Equation Definitions

10.1.1 Terms

The following table defines the indices used to identify different terms in the settlement equations.

Term	Definition
c(k)	Denotes a *registered trading right* on *market facility* k. A *registered trading right* c(k) can be for *supply* of gas to the *hub* (represented by ct(k)) or for withdrawal of gas from the *hub* (represented by cf(k)).
cf(k)	Denotes a *registered trading right* that allows withdrawal of gas from the *hub* on *market facility* k. See c(k).
ct(k)	Denotes a *registered trading right* that allows *supply* of gas to the *hub* on *market facility* k. See c(k).
d	Denotes a *gas day*.
f	Denotes a step of the *variation settlement function*. Each step corresponds to a variation percentage range and variation quantity range described in *rule* 463. A finite number of steps are defined where each step must have a PVarR(f) value and a PVarF(f) value (for the *percentage method*) or a GVarR(f) value and a GVarF(f) value (for the *quantity method*). When comparing one step with another, the term f' may be used to indicate a step other than f.
f'	Denotes a step of the *variation settlement function*. See f.
fd	Denotes an index representing flow direction and takes the value "to" or "from" for terms relating to gas flows to or from the *hub* respectively. For an *STTM Shipper* supplying the *hub* on an *STTM facility* ($k \in SP$) fd = "to". For an *STTM Shipper* withdrawing gas from the *hub* on an *STTM facility* ($k \in SP$) fd = "from". For an *STTM User* withdrawing gas from the *hub* ($k \in SN$) fd = "from".
j	Denotes a *price step* of a *MOS increase offer* or *MOS decrease offer*.
k	Denotes a *market facility*.
m(k)	Denotes a *MOS increase offer* or a *MOS decrease offer* that is included by *AEMO* in a *MOS increase stack* or *MOS decrease stack* for *STTM pipeline* k for a *MOS period*.
p	Denotes a *Trading Participant.*

Term	Definition
	Note that a term being calculated for *Trading Participant* p may include references to other *Trading Participants* (eg. summations over all *Trading Participants*). In such instances p' is used to denote a member of the set of *Trading Participants*, and can be interpreted identically to p except that *Trading Participant* p' may be *Trading Participant* p or another *Trading Participant*.
p'	Denotes a *Trading Participant*. See p.

10.1.2 Sets

The following table defines the sets used in the settlement equations.

Term	Definition
AH	Denotes the set of *registered trading rights* for *as available capacity* that allow the *supply* of gas to a *hub*. This set does not include *registered trading rights* that allow withdrawal of gas from the *hub*.
BP	Denotes the set of *gas days* in a *billing period*.
FH	Denotes the set of *registered trading rights* for *firm haulage* that allow the *supply* of gas to a *hub*. This set does not include *registered trading rights* that allow withdrawal of gas from the *hub*.
SN	Denotes the set containing a single member representing all of the *STTM distribution systems* for a *hub*.
SP	Denotes the set of *STTM facilities* serving a *hub*.

10.1.3 Mathematical terms

The following table defines all the mathematical terms used in the settlement equations.

Term	Definition
AHC(p,d)	An *ad hoc charge* for *Trading Participant* p for *gas day* d, being an amount payable by that *Trading Participant* for the purposes of *rule* 464(2)(c) and to be accounted for in the settlement shortfall and surplus calculation in clause 10.10.
AHP(p,d)	An *ad hoc payment* for *Trading Participant* p for *gas day* d, being an amount payable to that *Trading Participant* for the purposes of *rule* 464(2)(d) and to be accounted for in the settlement shortfall and surplus calculation in clause 10.10.

Term	Definition
AllCAP	The settlement surplus *cap*. The settlement surplus cap is $0.14/GJ.
AQ^S(p,d,c(k))	The *allocated quantity* (including *MOS gas*) for the *supply* of gas to the *hub*; or withdrawal of gas from the *hub* by *Trading Participant* p (as an *STTM Shipper*) on *gas day* d on *registered trading right* c(k) on *market facility* k∈SP (an *STTM facility*). This value is determined in accordance with *rule* 420.
AQ^U(p,d,c(k))	The *allocated quantity* for the withdrawal of gas from the *hub* by *Trading Participant* p (as an *STTM User*) on *gas day* d on *registered trading right* c(k) on *market facility* k∈SN. This value is determined in accordance with *rule* 422.
CAP(p,d,c(k))	The *capacity limit* of *registered trading right* c(k) on *market facility* k *registered* to *Trading Participant* p for *gas day* d. This value is determined in accordance with *rule*s 384, 385 and 386 (as applicable).
CGC(p,d)	The *contingency gas* charge amount payable by *Trading Participant* p for a *hub* for *gas day* d determined in clause 10.6(b).
CGP(p,d)	The *contingency gas* payment amount payable to *Trading Participant* p for a *hub* for *gas day* d determined in clause 10.6(a).
CGPH(d)	The *high contingency gas price* for a *hub* for *gas day* d. This term is null (i.e. has no impact on settlement) unless *contingency gas* was *scheduled* to increase net *supply* to the *hub* on *gas day* d. This value is determined in accordance with *rule* 447.
CGPL(d)	The *low contingency gas price* for a *hub* for *gas day* d. This term is null (i.e. has no impact on settlement) unless *contingency gas* was *scheduled* to decrease net *supply* to the *hub* on *gas day* d. This value is determined in accordance with *rule* 448.
CP(d,k)	The *capacity price* for *market facility* k∈SP (an *STTM facility*) on *gas day* d. This term is greater than or equal to zero. This value is determined in accordance with *rule* 417.
CQ^S(p,d,k,fd)	The quantity of *contingency gas scheduled* by *AEMO* under *rule* 446 for *Trading Participant* p (as an *STTM Shipper*) for *gas day* d on *market facility* k∈SP (an *STTM facility*) and in flow direction fd. This term may be positive or negative, where a positive value for *supply* to the *hub* increases net *supply* to the *hub*, while a positive value for withdrawal from the *hub* decreases net *supply* to the *hub*. This value is determined in accordance with *rule* 446.
CQP^S(p,d,k,fd)	The quantity of *contingency gas AEMO* has determined to have been delivered under rule 449(3) for *Trading Participant* p (as an *STTM Shipper*) on *gas day* d on *market facility* k∈SP (an *STTM facility*) and in flow direction fd. This term may be positive or negative, where a positive value for supply to the *hub* increases net supply to the *hub*,

Term	Definition
	while a positive value for withdrawal from the *hub* decreases net supply to the *hub*.
CQP^U(p,d,k,fd)	The quantity of *contingency gas AEMO* has determined to have been delivered under rule 449(3) for *Trading Participant* p (as an *STTM User*) on *gas day* d on *market facility* k∈SN and in flow direction fd (fd="from" only).This term may be positive or negative, where a positive value for withdrawal from the *hub* decreases net supply to the *hub*.
CQT(d,k)	The capacity quantity traded between *Trading Participants* with *as available capacity* and *Trading Participants* with *firm capacity* on *market facility* k∈SP (an *STTM facility*) for *gas day* d. This value is determined in clause 10.9.1(e).
CQ^U(p,d,k,fd)	The quantity of *contingency gas scheduled* by *AEMO* under *rule* 446 for *Trading Participant* p (as an *STTM User*) for *gas day* d on *market facility* k∈SN and in flow direction fd (fd= "from" only). This term may be positive or negative, where a positive value for withdrawal from the *hub* decreases net *supply* to the *hub*. This value is determined in accordance with *rule* 446.
CSC(p,d,k,fd)	The change, due to *market schedule variations*, to be applied to the *market schedule quantity* in forming the *modified market schedule quantity* for *Trading Participant* p on *gas day* d for *market facility* k for flows in direction fd, where the change is subject to *variation charge*s. This value is determined in clause 10.5.1.
DevC(p,d)	The *deviation charge* amount payable by *Trading Participant* p for a *hub* for *gas day* d determined in clause 10.8.11(f).
DevP(p,d)	The *deviation payment* amount payable to *Trading Participant* p for a *hub* for *gas day* d determined in clause 10.8.11(e).
DevNFA(p,d,k)	The *settlement amount* for *Trading Participant* p for negative deviations in withdrawals from the *hub* on *market facility* k on *gas day* d determined in clause 10.8.11(b).
DevNTA(p,d,k)	The *settlement amount* for *Trading Participant* p for negative deviations in gas supplied to the *hub* on *gas day* d determined in clause 10.8.11(d).
DevPFA(p,d,k)	The *settlement amount* for *Trading Participant* p for positive deviations in withdrawals from the *hub* on *market facility* k on *gas day* d determined in clause 10.8.11(a).
DevPTA(p,d,k)	The *settlement amount* for *Trading Participant* p for positive deviations in gas supplied to the *hub* on *gas day* d determined in clause 10.8.11(c).
DPFlag(d)	The DPFlag(d) can be 0 or 1 for a *hub* and a *gas day*. It is set by AEMO in accordance with clause 8.2.2(c). If it is 0, then settlement calculations are unaffected. If it is 1, then all *long deviation quantities*

Term	Definition
	are settled at the *ex ante market price*, while all *short deviation quantities* are settled at the maximum price applicable to *gas day* d (MAXP(d)).
DQB(p)	The *billing period deviation quantity* for *Trading Participant* p for a *hub* determined in clause 10.10.2.
DQF(p,d,k)	The total GJ deviation of *Trading Participant* p withdrawing gas from the *hub* on *market facility* k on *gas day* d. If it is positive, the *Trading Participant* is long with respect to *market facility* k; if it is negative, the *Trading Participant* is short with respect to *market facility* k. This is determined in clauses 10.8.2(a) and 10.8.2(b).
DQT(p,d,k)	The total GJ deviation of *Trading Participant* p supplying gas to the *hub* on *market facility* k on *gas day* d. If it is positive, the *Trading Participant* is long with respect to *market facility* k; if it is negative, the *Trading Participant* is short with respect to *market facility* k. This is determined in clauses 10.8.2(c) and 10.8.2(d).
DVA(p)	The settlement shortfall or settlement surplus allocation on *deviation quantities* for a *hub* and a *billing period* to *Trading Participant* p. This is determined in clause 10.10.3.
EAQ^S(p,d,ct(k))	The effective *allocated quantity* for *Trading Participant* p and *gas day* d for *registered trading right* ct(k) which allows the *supply* of gas to the *hub* on *market facility* k∈SP (an *STTM facility*). This is the total *allocated quantity* for that *registered trading right* corrected to remove the allocation of *MOS gas* to that *registered trading right*. This is determined in clause 10.9.1(a).
ECCA(d,k)	The effective *capacity charge* rate for *registered trading rights* for *as available capacity* on *gas day* d and *market facility* k∈SP (an *STTM facility*). This is determined in clause 10.9.2(a).
ECPF(d,k)	The effective *capacity payment* rate for *registered trading rights* for *firm capacity* on *gas day* d and *market facility* k∈SP (an *STTM facility*). This is determined in clause 10.9.2(b).
FDCP(d,k)	The *pipeline flow direction constraint price* for *gas day* d on *market facility* k∈SP (an *STTM facility*). This price is positive in value if the constraint restricts flow and is zero otherwise. This value is determined in accordance with *rule* 417.
FGO(p,d,ct(k))	The deemed firm gas offered to be supplied to the *hub* by *Trading Participant* p (as an *STTM Shipper*) for *gas day* d on *registered trading right* ct(k) for *firm capacity* on *market facility* k∈SP (an *STTM facility*). This is determined in clause 10.9.1(b).
FSC(p,d,k,fd)	The change, due to *market schedule variations*, to be applied to the *market schedule quantity* for *Trading Participant* p for *gas day* d for *market facility* k for flows in direction fd, where the change is not

Term	Definition
	subject to *variation charges*. This value is determined in clause 10.5.1.
GMI	The gross market income for a *hub* for a *billing period*. This is the total amount, excluding *variation charges*, received by *AEMO* for a *hub* for a *billing period*. This value is determined in clause 10.10.1(a).
GMO	Gross market outgoings for a *hub* for a *billing period*. This is the total amount paid by *AEMO* for a *hub* for a *billing period*. This value is determined in clause 10.10.1(b).
GVarC(p,d)	The *variation charge* for *Trading Participant* p for a *hub* for *gas day* d determined using the *quantity method*. This term is greater than or equal to zero. This value is determined in clause 10.5.4(b).
GVarF(f)	The factor for step f of the *quantity method variation settlement function*. These factors increase with increasing variation quantity and are the factors for the variation quantity range (specified in GJ) in *rule* 463 corresponding to step f.
GVarR(f)	The GJ boundary between step f and step f+1 for the *quantity method variation settlement function*. These terms are positive valued and correspond to the most positive values specified in the variation quantity range (specified in GJ) in *rule* 463 corresponding to step f. This term is neither defined nor used for f=Maxf.
GVarU(p,d,f)	The variation quantity of step f for *Trading Participant* p *quantity method* variations for a *hub* on *gas day* d. This term is greater than or equal to zero. This value is determined in clause 10.5.4(a).
HP(d)	The *ex ante market price* for a *hub* for *gas day* d. This value is determined in accordance with *rule* 417.
IHP(d)	The *ex post imbalance price* for a *hub* for *gas day* d. This value is determined in accordance with *rule* 426.
LD(d,k)	A value of 0 or 1 to control whether or not a *Trading Participant's* deviation for *gas day* d which decreases net *supply* (i.e. *supply* less consumption) to a *hub* is included in the allocation of settlement surpluses and shortfalls for the *billing period* containing *gas day* d. The daily deviation is included if LD(d,k) = 1, but not if LD(d,k) = 0. The value of LD(d,k) is determined in clause 10.10.2.
LDQ(p,d)	The *long deviation quantity* for *Trading Participant* p at a *hub* on *gas day* d.
LI(d,k)	A value of 0 or 1 to control whether or not a *Trading Participant's* deviation for *gas day* d which increases net *supply* (i.e. *supply* less consumption) at a *hub* is included in the allocation of settlement surpluses and shortfalls for the *billing period* containing *gas day* d. The daily deviation is included if LI(d,k) = 1, but not if LI(d,k) = 0. The value of LI(d,k) is determined in clause 10.10.2.

Term	Definition
$MAQ^{S}(p,d,cf(k))$	The quantity of *MOS gas* (excluding *overrun MOS*) allocated to flow from the *hub* on *registered trading right* cf(k) on *market facility* k∈SP (an *STTM facility*) on *gas day* d by *Trading Participant* p. This value may be positive or negative. A positive value indicates increased net flow to the *hub* implying a decreased flow from the *hub* on the *registered trading right*.
$MAQ^{S}(p,d,ct(k))$	The quantity of *MOS gas* (excluding *overrun MOS*) allocated to flow to the *hub* on *registered trading right* ct(k) on *market facility* k∈SP (an *STTM facility*) on *gas day* d by *Trading Participant* p. This value may be positive or negative. A positive value indicates increased net flow to the *hub* implying an increased flow to the *hub* on the *registered trading right*.
Maxf	The last step (f = Maxf) of the *variation settlement function*, being the step with the greatest value of PVarF(f) (for the *percentage method*) or GVarF(f) (for the *quantity method*).
MAXP(d)	The maximum *deviation price* to be applied in the settlement of *gas day* d for a *hub*. This will normally be *MPC* plus MCAP but will be equal to the *administered price cap* when either an *administered price cap state, administered ex post pricing state, market administered scheduling state* or *market administered settlement state* applies to *gas day* d.
MCAP	The *MOS cost cap*.
MCCC(p,d)	The *MOS* cash-out charge for *Trading Participant* p for a *hub* for *gas day* d for the restoration of *MOS gas* provided under one or more *MOS decrease offers*. This is determined in clause 10.7.4(b).
MCCP(p,d)	The *MOS* cash-out payment to *Trading Participant* p for a *hub* for *gas day* d for the restoration of *MOS gas* provided under one or more *MOS increase offers*. This is determined in clause 10.7.4(a).
MCOC(p,d)	The *MOS* cash-out charge for *Trading Participant* p for a *hub* for *gas day* d for the restoration of *MOS gas* provided as *overrun MOS*. This is determined in clause 10.7.4(d).
MCOP(p,d)	The *MOS* cash-out payment to *Trading Participant* p for a *hub* for *gas day* d for the restoration of *MOS gas* provided as *overrun MOS*. This is determined in clause 10.7.4(c).
MCP(p,d)	The payment to *Trading Participant* p for the provision of *MOS* to a *hub* on *gas day* d. This payment excludes settlement of gas flowed (or not flowed) or any payments or charges for *overrun MOS*. This is determined in clause 10.7.3(a).
MINP(d)	The minimum *deviation price* to be applied in the settlement of *gas day* d for a *hub*. This will normally be *MMP* less the MCAP for that *gas day* but will be equal to *MMP* when either an *administered price cap state, administered ex post pricing state, market administered*

Term	Definition
	scheduling state or *market administered settlement state* applies to *gas day* d.
MktC(p,d)	The *ex ante market charge* for *Trading Participant* p for a *hub* for *gas day* d. This is determined in clause 10.3(b).
MktP(p,d)	The *ex ante market payment* for *Trading Participant* p for a *hub* for *gas day* d. This is determined in clause 10.3(a).
$MMSQ^S(p,d,k,fd)$	The *modified market schedule quantity* for *Trading Participant* p acting as an *STTM Shipper* on *market facility* $k \in SP$ (an *STTM facility*) for flow in direction fd on *gas day* d. This is determined in clause 10.8.1(a).
$MMSQ^U(p,d,k,fd)$	The *modified market schedule quantity* for *Trading Participant* p acting as an *STTM User* on *market facility* $k \in SN$ for flow in direction fd (which must be to the *hub*) on *gas day* d. This is determined in clause 10.8.1(b).
MOP(p,d)	The payment to *Trading Participant* p for the provision of *MOS* to a *hub* as *overrun MOS* on *gas day* d. This payment excludes settlement for gas flowed (or not flowed). This is determined in clause 10.7.3(b).
$MOSAD^S(p,d,m(k),j)$	The quantity of *MOS gas* allocated to the j^{th} *price step* of *Trading Participant* p's *MOS decrease offer* m(k) on *gas day* d on *market facility* k. This is a positive value. This value is determined for a *registered facility service* in accordance with *rule* 421.
$MOSAI^S(p,d,m(k),j)$	The quantity of *MOS gas* allocated to the j^{th} *price step* of *Trading Participant* p's *MOS increase offer* m(k) on *gas day* d on *market facility* k. This is a positive value. This value is determined for a *registered facility service* in accordance with *rule* 421.
MosC(p,d)	The *MOS* charge to *Trading Participant* p for a *hub* for *gas day* d. This is determined in clause 10.7.5(b).
$MOSDC^S(p,d,m(k),j)$	The *MOS price* for *price step* j contained in a *MOS decrease offer* m(k) for *Trading Participant* p on *gas day* d on *market facility* $k \in SP$ (an *STTM facility*). This value is specified in the *MOS decrease offer* submitted in accordance with *rule* 400.
MOSFP(p,d,m(k))	A fixed payment (if any) for *gas day* d to *Trading Participant* p for *MOS increase offer* or *MOS decrease offer* m(k) on *market facility* $k \in SP$.
$MOSIC^S(p,d,m(k),j)$	The *MOS price* for *price step* j contained in a *MOS increase offer* m(k) for *Trading Participant* p on *gas day* d on *market facility* $k \in SP$ (an *STTM facility*). This value is specified in the *MOS increase offer* submitted in accordance with *rule* 400.

Term	Definition
MosP(p,d)	The *MOS* payment to *Trading Participant* p for a *hub* for *gas day* d. This is determined in clause 10.7.5(a).
MOSRD(d,k)	The estimated maximum *MOS* decrease (in GJ) on *market facility* k for *gas day* d. This is a positive value but will be zero for *facilities* which do not provide *MOS* (e.g. *STTM distribution systems* and *STTM facilities* other than *STTM pipelines*). This value relates to a *MOS period*. This value is determined in accordance with *rule* 397.
MOSRI(d,k)	The estimated maximum *MOS* increase (in GJ) on *market facility* k for *gas day* d. This is a positive value but will be zero for *facilities* which do not provide *MOS* (e.g. *STTM distribution systems* and *STTM facilities* other than *STTM pipelines*). This value relates to a *MOS period*. This value is determined in accordance with *rule* 397.
MOSXD(d)	The MOS decrease cost for a *hub* for *gas day* d. This term is null (i.e. has no impact on settlement) unless the net quantity of *MOS gas* allocated on all *STTM facilities* supplying the *hub* on *gas day* d is negative (decrease *MOS*). This value is determined in clause 10.8.4B.
MOSXI(d)	The MOS increase cost for a *hub* for *gas day* d. This term is null (i.e. has no impact on settlement) unless the net quantity of *MOS gas* allocated on all *STTM facilities* supplying the *hub* on *gas day* d is positive (increase *MOS*). This value is determined in clause 10.8.4A.
MQ^S(p,d,cf(k))	The *market schedule quantity* for gas withdrawn from the *hub* by *Trading Participant* p as an *STTM Shipper* on *gas day* d on *registered trading right* cf(k) for *market facility* k∈SP (an *STTM facility*). This value is determined in accordance with *rule* 417.
MQ^S(p,d,ct(k))	The *market schedule quantity* for gas supplied to the *hub* by *Trading Participant* p as an *STTM Shipper* on *gas day* d on *registered trading right* ct(k) for *market facility* k∈SP (an *STTM facility*). This value is determined in accordance with *rule* 417.
MQ^U(p,d,cf(k))	The *market schedule quantity* for gas withdrawn from the *hub* by *Trading Participant* p as an *STTM User* on *gas day* d on *registered trading right* cf(k) for *market facility* k∈SN. This value is determined in accordance with *rule* 417.
MSV[d,(sp,sk,sfd), (cp,ck,cfd)]	The quantity associated with a *market schedule variation* for *gas day* d, submitted by *Trading Participant* p=sp under *rule* 423 and pertaining to the *schedules* of *Trading Participant* p=sp on *market facility* k=sk for flows in direction fd=sfd, with this quantity offset against the schedule of *Trading Participant* p=cp on *market facility* k=ck for flows in direction fd=cfd. This value is determined in accordance with *rule* 423.
NMB	The settlement surplus or shortfall for a *hub* for a *billing period* excluding the impact of *variation charge*s. If this is positively valued then a market surplus is allocated based on *billing period deviation*

Term	Definition
	quantities. If this is negatively valued then a market shortfall is allocated based on *billing period deviation quantities*. This is determined in clause 10.10.1(c).
$OMAQ^{S}$(p,d,cf(k))	The quantity of *MOS gas* that is *overrun MOS* allocated to flow from the *hub* on *registered trading right* cf(k) on *market facility* k∈SP (an *STTM facility*) on *gas day* d by *Trading Participant* p. This value may be positive or negative. A positive value indicates increased net flow to the *hub* implying a decreased flow from the *hub* on the *registered trading right*. This value is determined for a *registered facility service* in accordance with *rule* 421 and is associated with the *registered trading right* of the *contract holder* for that *registered facility service*.
$OMAQ^{S}$(p,d,ct(k))	The quantity of *MOS gas* that is *overrun MOS* allocated to flow to the *hub* on *registered trading right* ct(k) on *market facility* k∈SP (an *STTM facility*) on *gas day* d by *Trading Participant* p. This value may be positive or negative. A positive value indicates increased net flow to the *hub* implying an increased flow to the *hub* on the *registered trading right*. This value is determined for a *registered facility service* in accordance with *rule* 421 and is associated with the *registered trading right* of the *contract holder* for that *registered facility service*.
OQF^{S}(p,d,c(k))	The quantity of gas offered by *Trading Participant* p on *registered trading right* c(k) with *firm capacity* on *market facility* k to be supplied to the *hub* on *gas day* d. This value is determined in accordance with *rule* 407.
ORPD(d,k)	The *overrun MOS* decrease price for *market facility* k on *gas day* d. This is determined in clause 10.7.2(b).
ORPI(d,k)	The *overrun MOS* increase price for *market facility* k on *gas day* d. This is determined in clause 10.7.1(b).
PFDCC(p,d)	The *pipeline flow direction constraint charge* payable by *Trading Participant* p for the withdrawal of gas from a *hub* on *gas day* d. This value is determined in clause 10.4(b).
PFDCP(p,d)	The *pipeline flow direction constraint payment* payable to *Trading Participant* p for the *supply* of gas to a *hub* on *gas day* d. This value is determined in clause 10.4(a).
PDevNF(p,d,k)	The *deviation price* for *a short deviation quantity* for *Trading Participant* p on *gas day* d for withdrawals from the *hub* on *market facility* k. This value is determined in clause 10.8.5(b).
PDevNT(p,d,k)	The *deviation price* for *a short deviation quantity* for *Trading Participant* p on *gas day* d for *supply* to the *hub* on *market facility* k. This value is determined in clause 10.8.5(d).
PDevPF(p,d,k)	The *deviation price* for *a long deviation quantity* for *Trading Participant* p on *gas day* d for withdrawals from the *hub* on *market facility* k. This value is determined in clause 10.8.5(a).

Term	Definition
PDevPT(p,d,k)	The *deviation price* for *a long deviation quantity* for *Trading Participant* p on *gas day* d for *supply* to the *hub* on *market facility* k. This value is determined in clause 10.8.5(c).
PVarC(p,d)	The *variation charge* for *Trading Participant* p for *gas day* d for a *hub*, determined using the *percentage method*. This term is greater than or equal to zero. This value is determined in clause 10.5.3(b).
PVarF(f)	The factor for step f of the *percentage method variation settlement function*. These factors increase with increasing variation quantity and are the factors for the variation percentage range in *rule* 463 corresponding to step f.
PVarR(f)	The percentage boundary between step f and step f+1 for the *percentage method variation settlement function*. These are positive values and correspond to the most positive values specified in the variation percentage range in *rule* 463 corresponding to step f. This term is neither defined nor used for f=Maxf.
PVarU(p,d,f)	The variation quantity of step f for *Trading Participant* p *percentage method* variations on *gas day* d for a *hub*. This term is greater than or equal to zero. This value is determined in clause 10.5.3(a).
RDevN(d)	A revised *deviation price* for a *short deviation quantity* at a *hub* on *gas day* d. This value is determined in clause 10.6B and applied only for the purposes of *contingency gas* resettlement.
RDevP(d)	A revised *deviation price* for a *long deviation quantity* at a *hub* on *gas day* d. This value is determined in clause 10.6B and applied only for the purposes of *contingency gas* resettlement.
S (superscript)	Indicates an *STTM Shipper* specific term.
SCC(p,d)	The *capacity charge* for *Trading Participant* p as an *STTM Shipper* for a *hub* for *gas day* d. This is determined in clause 10.9.3(a).
SCP(p,d)	The *capacity payment* for *Trading Participant* p as an *STTM Shipper* for a *hub* for *gas day* d. This is determined in clause 10.9.3(b).
SDQ(p,d)	The *short deviation quantity* for *Trading Participant* p at a *hub* on *gas day* d.
SSC(p)	The *settlement shortfall charge* payable by *Trading Participant* p for a *hub* for a *billing period*. This is determined in clause 10.10.5(b).
SSP(p)	The *settlement surplus payment* payable to *Trading Participant* p for a *hub* for a *billing period*. This is determined in clause 10.10.5(a).
TAFGQ(d,k)	The total quantity of gas allocated to *registered trading rights* for *as available capacity* on *gas day* d on *market facility* k$\in$SP (an *STTM facility*). This is determined in clause 10.9.1(c).

Term	Definition
TCMDQ(d,k)	The total quantity of decreased gas flow allocated as *MOS gas* (excluding *overrun MOS*) on *market facility* k∈SP (an *STTM facility*) on *gas day* d. This is determined in clause 10.7.2(a).
TCMIQ(d,k)	The total quantity of increased gas flow allocated as *MOS gas* (excluding *overrun MOS*) on *market facility* k∈SP (an *STTM facility*) and *gas day* d. This is determined in clause 10.7.1(a).
TFGNQ(d,k)	The total quantity of gas offered to be supplied to the *hub* under *registered trading rights* for *firm capacity* but not allocated as flowed for *gas day* d on k∈SP (an *STTM facility*). This is determined in clause 10.9.1(d).
U (superscript)	Indicates an *STTM User* specific term.
VarC(p,d)	The *variation charge* for *Trading Participant* p for *gas day* d for a *hub*. This is determined in clause 10.5.5.
VQ(p,d)	The total GJ variation of *Trading Participant* p for *gas day* d for a *hub*. This term is greater than or equal to zero. This is determined in clause 10.5.2.
WDA(p)	The settlement shortfall or surplus amount for a *hub* for a *billing period* allocated to *Trading Participant* p as a result of its allocated withdrawals from the *hub* over the *billing period* (whether as an *STTM Shipper* or as an *STTM User*). This amount includes a share of *variation charge*s applied to *Trading Participants* over the *billing period* and any settlement shortfall or surplus not included in the value of DVA(p). This is determined in clause 10.10.4.

10.2 Amounts for gas days

(a) For the purposes of *rule* 461(1), the *modified market schedule* for each *hub* for each *gas day* to be determined by *AEMO* is the set of *modified market schedule quantities* for that *hub* and *gas day* for all *Trading Participants,* where each *Trading Participant* has a *modified market schedule quantity* for:

(i) flow to the *hub* on each *STTM facility*, described by $MMSQ^S$(p,d,k,fd) where fd denotes flow to the *hub* in clause 10.8.1(a);

(ii) flow from the *hub* on each *STTM facility*, described by $MMSQ^S$(p,d,k,fd) where fd denotes flow from the *hub* in clause 10.8.1(a); and

(iii) flow from the *hub* on the *STTM distribution system*, described by $MMSQ^U$(p,d,k,fd) in clause 10.8.1(b);

(b) For the purposes of *rule* 461(2)(a), the sum across all *hubs* of the *ex ante market charge* payable by a *Trading Participant* at each *hub* is to be determined by *AEMO* for each *gas day* by summing over all *hubs* the value of MktC(p,d) determined in accordance with clause 10.3(b).

(c) For the purposes of *rule* 461(2)(a), the sum across all *hubs* of the *ex ante market payment* payable to a *Trading Participant* at each *hub* is to be determined by *AEMO* for each *gas day* by summing over all *hubs* the value of MktP(p,d) determined in accordance with clause 10.3(a).

(d) For the purposes of *rule* 461(2)(b), the sum across all *hubs* of the *variation charge*s payable by a *Trading Participant* in respect of *market schedule variations* at each *hub* is to be determined by *AEMO* for each *gas day* by summing over all *hubs* the value of VarC(p,d) determined in accordance with clause 10.5.5.

(e) For the purposes of *rule* 461(2)(c), the sum across all *hubs* of the *pipeline flow direction constraint charge* payable by a *Trading Participant* (as an *STTM Shipper*) at each *hub* is to be determined by *AEMO* for each *gas day* by summing over all *hubs* the value of PFDCC(p,d) determined in accordance with clause 10.4(b).

(f) For the purposes of *rule* 461(2)(c), the sum across all *hubs* of the *pipeline flow direction constraint payment* payable by a *Trading Participant* (as an *STTM Shipper*) at each *hub* is to be determined by *AEMO* for each *gas day* by summing over all *hubs* the value of PFDCP(p,d) determined in accordance with clause 10.4(a).

(g) For the purposes of *rule* 461(2)(d), the sum across all *hubs* of the amount payable to a *Trading Participant* (as an *STTM Shipper*) (whether in its capacity as *MOS provider* or otherwise) for the provision of *MOS* or *overrun MOS* at each *hub* is to be determined by *AEMO* for each *gas day* by summing over all *hubs* the sum of the value of MCP(p,d) determined in accordance with clause 10.7.3(a) and the value of MOP(p,d) determined in accordance with clause 10.7.3(b).

(h) For the purposes of *rule* 461(2)(e), the sum across all *hubs* of the amount payable to a *Trading Participant* (as an *STTM Shipper*) for the restoration of *MOS gas* provided at each *hub* on the second *gas day* before that *gas day* is to be determined by *AEMO* for each *gas day* by summing over all *hubs* the sum of the value of MCCP(p,d) determined in accordance with clause 10.7.4(a) and the value of MCOP(p,d) determined in accordance with clause 10.7.4(c).

(i) For the purposes of *rule* 461(2)(e), the sum across all *hubs* of the amount payable by a *Trading Participant* (as an *STTM Shipper*) for the restoration of *MOS gas* provided at each *hub* on the second *gas day* before that *gas day* is to be determined by *AEMO* for each *gas day* by summing over all *hubs* the sum of the value of MCCC(p,d) determined in accordance with clause 10.7.4(b) and the value of MCOC(p,d) determined in accordance with in clause 10.7.4(d).

(j) For the purposes of *rule* 461(2)(f), the sum across all *hubs* of the *capacity charge* payable by a *Trading Participant* (as an *STTM Shipper*) at each *hub* is to be determined by *AEMO* for each *gas day* by summing over all *hubs* the value of SCP(p,d) determined in accordance with clause 10.9.3(b).

(k) For the purposes of *rule* 461(2)(f), the sum across all *hubs* of the *capacity payment* payable to a *Trading Participant* (as an *STTM Shipper*) at each *hub* is to be determined by *AEMO* for each *gas day* by summing over all *hubs* the value of SCC(p,d) determined in accordance with clause 10.9.3(a).

(l) For the purposes of *rule* 461(2)(g), the sum across all *hubs* of the *deviation charge* payable by a *Trading Participant* at each *hub* is to be determined by *AEMO* for each *gas day* by summing over all *hubs* the value of DevC(p,d) determined in accordance with clause 10.8.11(f).

(m) For the purposes of *rule* 461(2)(g), the sum across all *hubs* of the *deviation payment* payable to a *Trading Participant* at each *hub* is to be determined by *AEMO* for each *gas day* by summing over all *hubs* the value of DevP(p,d) determined in accordance with clause 10.8.11(e).

(n) For the purposes of *rule* 461(2)(h), the sum across all *hubs* of the amount payable to a *Trading Participant* in respect of *contingency gas* is to be determined by *AEMO* for each *gas day* by summing over all *hubs* the value of CGP(p,d) determined in accordance with clause 10.6(a).

(o) For the purposes of *rule* 461(2)(h), the sum across all *hubs* of the amount payable by a *Trading Participant* in respect of *contingency gas* is to be determined by *AEMO* for each *gas day* by summing over all *hubs* the value of CGC(p,d) determined in accordance with clause 10.6(b).

10.3 Ex Ante Market Payments And Charges

Explanatory Note

This clause describes how *AEMO* determines the *ex ante market payment* and *ex ante market charge* for a *Trading Participant* at a *hub* for a *gas day* for the purposes of *rule* 461(2)(a). The *ex ante market payment* is determined in accordance with clause 10.3(a), by multiplying the *ex ante market price* by the sum of that *Trading Participant's market schedule quantities* for the *supply* of gas to the *hub*. The *ex ante market charge* is determined in accordance with clause 10.3(b), by multiplying the *ex ante market price* by the sum of that *Trading Participant's market schedule quantities* for the withdrawal of gas from the *hub*.

(a) The *ex ante market payment* for *Trading Participant* p for *gas day* d for the *hub* is:

$$\mathrm{MktP(p,d)} = \mathrm{HP(d)} \times \Sigma_{k \in SP}\, \Sigma_{ct(k)}\, \mathrm{MQ^S(p,d,ct(k))}$$

(b) The *ex ante market charge* for *Trading Participant* p for *gas day* d for the *hub* is:

$$\mathrm{MktC(p,d)} = \mathrm{HP(d)} \times \{\, \Sigma_{k \in SP}\, \Sigma_{cf(k)}\, \mathrm{MQ^S(p,d,cf(k))} + \Sigma_{k \in SN}\, \Sigma_{cf(k)}\, \mathrm{MQ^U(p,d,cf(k))} \,\}$$

10.4 Pipeline Flow Direction Constraint Payments and Charges

Explanatory Note

This clause describes how *AEMO* determines the *pipeline flow direction constraint payment* and *pipeline flow direction constraint charge* for a *Trading Participant* on each *STTM pipeline* for a *gas day* for the purposes of *rule* 461(2)(c). The *pipeline flow direction constraint payment* is determined in accordance with clause 10.4(a) by multiplying the *pipeline flow direction constraint price* for the *STTM pipeline* by the sum of that *Trading Participant's market schedule quantities* for the *supply* of gas to the *hub* on that *STTM pipeline*. The *pipeline flow direction constraint charge* is determined in accordance with clause 10.4(b) by multiplying the *pipeline flow direction constraint price* for the *STTM pipeline* by the sum of that *Trading Participant's market schedule quantities* for the withdrawal of gas from the *hub* on that *STTM pipeline*.

These payments and charges will only arise where there is a non-zero *pipeline flow direction constraint price*. This is expected to be rare, and will only occur if the *scheduled* flows to and from the *hub* on the *STTM pipeline* are equal.

(a) The *pipeline flow direction constraint payment* to *Trading Participant* p for the ex ante market *supply* of gas to the *hub* for *gas day* d is:

$$PFDCP(p,d) = \Sigma_{k \in SP} \{FDCP(d,k) \times \Sigma_{ct(k)} MQ^S(p,d,ct(k))\}$$

(b) The *pipeline flow direction constraint charge* to *Trading Participant* p for the ex ante market withdrawal of gas from the *hub* for *gas day* d is:

$$PFDCC(p,d) = \Sigma_{k \in SP} \{FDCP(d,k) \times \Sigma_{cf(k)} MQ^S(p,d,cf(k))\}$$

Note: These payments and charges result in those *STTM Shippers* shipping gas to the *hub* receiving payments from those *STTM Shippers* withdrawing gas from the *hub*. These amounts ensure that all *STTM Shippers* on a *facility* are paid or pay consistently with their bids and offers, even when *ex ante market scheduled* withdrawals from the *hub* on a *pipeline* are limited by and equal to the *ex ante market scheduled* flows to the *hub* on that *pipeline*.

10.5 Variation Charges

Explanatory Note

This clause describes how *AEMO* determines *variation charges* for a *Trading Participant* for the purposes of *rule* 461(2)(b). *Variation charges* are calculated in accordance with clauses 10.5.1 to 10.5.5, by:

(a) determining the quantity of *market schedule variations* that incur a *variation charge*, being those *market schedule variations* relating to the withdrawal of gas from the *hub* for which the *Trading Participant* was the *receiving Participant*;

(b) calculating charges for that quantity using both the *percentage method* and the *quantity method* under which the charge rate increases, with reference to the tables in *rule* 463, as the effect of the quantity of applicable variations increases; and

(c) determining the lesser of the charge calculated using the *percentage method* and charge calculated using the *quantity method*, which is to be the *variation charge* for that *Trading Participant*.

10.5.1 Processing of market schedule variations

(a) In processing a valid *market schedule variation,* for each combination of *Trading Participant* p, *gas day* d, *market facility* k and flow direction fd:

(i) first set FSC(p,d,k,fd) = 0 and CSC(p,d,k,fd)=0; and then

(ii) for each valid *market schedule variation* for *gas day* d which involves *Trading Participant* p and *market facility* k:

(A) add or subtract the *market schedule variation* quantity to FSC(p,d,k,fd) using the rules described in paragraph (c); and

(B) add or subtract the *market schedule variation* quantity to CSC(p,d,k,fd) using the rules described in paragraph (c).

(b) Each valid *market schedule variation* is described as MSV[d,(op,ok,ofd),(rp,rk,rfd)] where

(i) 'op' denotes the *originating Participant*;

(ii) 'ok' denotes the *originating Participant's STTM facility*;

(iii) 'ofd' denotes the direction of flow of the *originating Participant* for the purpose of the *market schedule variation*;

(iv) 'rp' denotes the *receiving Participant*;

(v) 'rk' denotes the *receiving Participant's market facility;*

(vi) 'rfd' denotes the direction of flow of the *receiving Participant* for the purpose of the *market schedule variation*;

(vii) FSC(op,d,ok,ofd) is identical to FSC(p,d,k,fd) with p=op, k=ok and fd=ofd;

(viii) FSC(rp,d,rk,rfd) is identical to FSC(p,d,k,fd) with p=rp, k=rk and fd=rfd;

(ix) CSC(op,d,ok,ofd) is identical to CSC(p,d,k,fd) with p=op, k=ok and fd=ofd; and

(x) CSC(rp,d,rk,rfd) is identical to CSC(p,d,k,fd) with p=rp, k=rk and fd=rfd.

(c) The rules as to how FSC(p,d,k,fd) and CSC(p,d,k,fd) for *Trading Participant* p, *gas day* d, *market facility* k and flow direction fd are updated for the purposes of paragraph (a)(ii) are described in the following table:

Originating Participant Facility	Originating Participant Direction	Receiving Participant Facility	Receiving Participant Direction	Sign of MSV[d, (op,ok,ofd), (rp,rk,rfd)]	Update to Apply to the FSC and CSC terms
ok∈SP	ofd='to'	rk∈SP [rk=ok in this case]	rfd='to'	>0	FSC(op,d,ok,ofd) = FSC(op,d,ok,ofd) + MSV[d, (op,ok,ofd), (rp,rk,rfd)] FSC(rp,d,rk,rfd) = FSC(rp,d,rk,rfd) - MSV[d, (op,ok,ofd), (rp,rk,rfd)]
ok∈SP	ofd='to'	rk∈SP or rk∈SN	rfd='from'	If MSV is to increase the *modified market schedule* of the *originating Participant*, >0 If MSV is to decrease the *modified market schedule* of the *originating STTM Shipper*, <0	FSC(op,d,ok,ofd) = FSC(op,d,ok,ofd) + MSV[d, (op,ok,ofd), (rp,rk,rfd)] CSC(rp,d,rk,rfd) = CSC(rp,d,rk,rfd) + MSV[d, (op,ok,ofd), (rp,rk,rfd)]
ok∈SP	ofd='from'	rk∈SP [rk=ok in this case]	rfd='from'	>0	FSC(op,d,ok,ofd) = FSC(op,d,ok,ofd) + MSV[d, (op,ok,ofd), (rp,rk,rfd)] FSC(rp,d,rk,rfd) = FSC(rp,d,rk,rfd) - MSV[d, (op,ok,ofd), (rp,rk,rfd)]
ok∈SP	ofd='from'	rk∈SN	rfd='from'	If MSV is to increase the *modified market schedule* of the *originating Participant*, >0 If MSV is to decrease the *modified market schedule* of the *originating Participant*, <0	FSC(op,d,ok,ofd) = FSC(op,d,ok,ofd) + MSV[d, (op,ok,ofd), (rp,rk,rfd)] FSC(rp,d,rk,rfd) = FSC(rp,d,rk,rfd) - MSV[d, (op,ok,ofd), (rp,rk,rfd)]
ok ∈SN	ofd='from'	rk∈SN	rfd='from'	>0	FSC(op,d,ok,ofd) = FSC(op,d,ok,ofd) + MSV[d, (op,ok,ofd), (rp,rk,rfd)]

Originating Participant Facility	Originating Participant Direction	Receiving Participant Facility	Receiving Participant Direction	Sign of MSV[d, (op,ok,ofd), (rp,rk,rfd)]	Update to Apply to the FSC and CSC terms
					FSC(rp,d,rk,rfd) = FSC(rp,d,rk,rfd) - MSV[d, (op,ok,ofd), (rp,rk,rfd)]

10.5.2 Variation quantity

The total GJ variation quantity for *Trading Participant* p on *gas day* d for the *hub* is:

$$VQ(p,d) = ABS(\Sigma_k \Sigma_{fd}\ CSC(p,d,k,fd))$$

Note: This is the absolute value of the component of the cumulative changes to the market schedule due to *market schedule variations* which are subject to *variation charge*s.

Note: Each *Trading Participant* will have a single variation quantity (in GJ) for a *hub* for a *gas day*. If the *Trading Participant* is both an *STTM User* and an *STTM Shipper* hauling from the *hub*, then VQ(p, d) will reflect the net change in its withdrawals from the *hub* that are subject to variation changes. The actual total change in its market *schedule* (inclusive of all its *market schedule variations*) may be different, as MSVs which do not incur a charge (because they imply no net change in *hub* withdrawal) are not included in VQ(p,d).

10.5.3 Allocation to steps – Percentage method

Note: The total GJ variation volume is allocated to a number of steps reflecting different percentages of change relative to the market *schedule*.

(a) The variation quantity of *Trading Participant* p variations assigned to step f is defined as follows, starting from step f = 1 and then increasing f:

For f=1:

$$PVarU(p,d,f) = MIN(VQ(p,d),PVarR(f) \times \Sigma_k \{\Sigma_{cf(k)}\ MQ^U(p,d,cf(k)) + \Sigma_{cf(k)} MQ^S(p,d,cf(k))\})$$

For f>1 and f <Maxf:

$$PVarU(p,d,f) = MIN(VQ(p,d), PVarR(f) \times \Sigma_k\{\Sigma_{cf(k)}\ MQ^U(p,d,cf(k)) + \Sigma_{cf(k)} MQ^S(p,d,cf(k))\}) – \Sigma_{f'<f}\ PVarU(p,d,f')$$

For f= Maxf:

$$PVarU(p,d,f) = VQ(p,d) – \Sigma_{f'<f}\ PVarU(p,d,f')$$

Note: That is, the total of variations is assigned to steps, where each step is defined as a fraction of the *ex ante market schedule* for *STTM Users* and *STTM Shippers* withdrawing from the *hub*. Thus if the *ex ante market schedule* is $\Sigma_k\{ \Sigma_{cf(k)} MQ^U(p,d,cf(k)) + \Sigma_{cf(k)} MQ^S(p,d,cf(k)) \} = 100$, the first step is PVaR(1)=3% of the market *schedule*, the second step is PVarR(2)=10% of the market *schedule*, and the third step is PVarR(3)=80% of the market *schedule*; and the raw variation is = -50, then VQ(p,d) = ABS(-50) or +50, PVarU(p,d,1) = min(50, 0.03×100) = 3, PVarU(p,d,2) = min(50, 0.1×100) -3 = 7, and PVarU(p,d,3) = min(50, .8 ×100) -10 = 40. Thus the total of *market schedule variations* of 50 is allocated into 3 steps of 3, 7, and 40. In the *variation charge* calculation, each of these steps is settled using its factor (PVarF(f) < 1) and is applied to the *ex ante market price* for the *hub*.

The last step (with f=Maxf) is used where there is no *ex ante market schedule* for withdrawal from the *hub* for the *Trading Participant*, which means that the entire variation quantity is associated with the final step. The maximum variation factor (ie. charge) will apply to this step.

(b) The percentage *variation charge* to *Trading Participant* p for *market schedule variations* for *gas day* d is:

If VQ(p,d) = 0

$$PVarC(p,d) = 0$$

Else

$$PVarC(p,d) = VQ(p,d) \times MIN(MAXP(d) – HP(d), ABS(HP(d)) \times \{\Sigma_f (PVarU(p,d,f) \times PVarF(f))\} / VQ(p,d))$$

Note: This equation states that if there is no variation then there is no *variation charge*. However, if there is a variation, then we calculate the per GJ cost of the total *variation charge*. If this charge rate is greater than the amount by which the maximum market price exceeds the *ex ante market price* then the raw *variation charge* rate is capped at the amount by which the maximum price exceeds the *ex ante market price*. The final rate is multiplied by the variation quantity. This approach effectively caps the average charge applied to be no greater than the applicable maximum market price less the *ex ante market price*. The maximum price allowed in the ex ante market for *gas day* d is MAXP(d) (which will either be *MPC,* or *APC* if prices are administered).

This ensures that a Trading Participant who traded its MSV quantity at the ex ante market price will never have a *variation charge* which would bring its total $/GJ payment for that gas to exceed the applicable maximum price in the market.

The absolute value of the *hub* price is used in defining the raw value so as to ensure that the *variation charge* is positive valued if HP(d) is negative.

10.5.4 Allocation to steps – Quantity method

(a) The variation quantity of *Trading Participant* p variations assigned to step f is defined as follows, starting from step f = 1 and then increasing f:

For f=1:

$$GVarU(p,d,f) = MIN(VQ(p,d), GVarR(f))$$

For f>1 and f <Maxf:

$$GVarU(p,d,f) = MIN(VQ(p,d), GVarR(f)) – \Sigma_{f'<f} GVarU(p,d,f')$$

For f= Maxf:

$$GVarU(p,d,f) = VQ(p,d) - \Sigma_{f'<f} GVarU(p,d,f')$$

Note: That is, the total of variations is assigned to steps, where each step is an absolute GJ quantity. Thus if the raw variation is -50GJ and the step boundaries are 10GJ, 60GJ and 80GJ then VQ(p,d) = ABS(-50) or 50, GVarU(p,d,1) = min(50,10) = 10, GVarU(p,d,2) = min(50,60) – 10 = 40, and GVarU(p,d,3) = min(50,80) – 10 – 40 = 0. Thus the total of *market schedule variations* of 50 is allocated into 3 steps of 10, 40 and 0. In the *variation charge* calculation, each of these steps is settled using its factor (GVarF(f) <1) and is applied to the *ex ante market price* for the *hub*.

The last step (with f = Maxf) has the otherwise unassigned variation associated with it.

(b) The GJ *variation charge* to *Trading Participant* p for *market schedule variations* for *gas day* d is:

If VQ(p,d) = 0

$$GVarC(p,d) = 0$$

Else

$$GVarC(p,d) = VQ(p,d) \times MIN(MAXP(d) – HP(d) , ABS(HP(d)) \times \{\Sigma_f (GVarU(p,d,f) \times GVarF(f))\} / VQ(p,d))$$

Note: This last equation works in much the same way as the corresponding equation for the percentage based approach.

The maximum price allowed in the ex ante market for *gas day* d is MAXP(d) (which will either be *MPC* or *APC* if prices are administered).

10.5.5 Variation charge

(a) Subject to paragraph (b), the *variation charge* for *Trading Participant* p for *market schedule variations* for *gas day* d for the *hub* is:

VarC(p,d) = MIN(PVarC(p,d), GVarC(p,d)).

(b) If a *market administered scheduling state* or a *market administered settlement state* applies for *gas day* d at a *hub*, the *variation charge* for each *Trading Participant* p for *market schedule variations* at that *hub* will be zero.

10.6 Contingency Gas Payments and Charges

Explanatory Note

This clause describes how AEMO determines amounts payable by or to a *Trading Participant* in respect of *contingency gas* at a *hub* for the purposes of *rule* 461(2)(h). Amounts payable to a *Trading Participant* are determined in accordance with clause 10.6(a), by multiplying the *high contingency gas price* by the quantity of *contingency gas scheduled* for that *Trading Participant* to increase net *supply* of gas to the *hub*. Amounts payable by a *Trading Participant* are determined in accordance with clause 10.6(b), by multiplying the *low contingency gas price* by the quantity of *contingency gas scheduled* for that *Trading Participant* to decrease net *supply* of gas to the *hub*.

The amounts paid by *Trading Participants* are not intended to equal the amounts paid to *Trading Participants*. Cost recovery for these amounts is achieved through *deviation charges*, *settlement shortfall charges* or *settlement surplus payments*. Rather, *Trading Participants* make payments for *contingency gas* where there is a surplus of gas *supply* at the *hub*, and those *Trading Participants* are effectively bidding to buy gas back from the market on the *gas day*. This is expected to be a rare occurrence.

(a) The payment to *Trading Participant* p for *gas day* d when *contingency gas* is *scheduled* to increase net *supply* to the *hub* is:

$$CGP(p,d) = CGPH(d) \times \{ \Sigma_{k\in SP} MAX(0,CQ^S(p,d,k,fd=\text{“to”})) + \Sigma_{k\in SN} MAX(0, -1 \times CQ^U(p,d,k,fd=\text{“from”})) + \Sigma_{k\in SP} MAX(0, -1 \times CQ^S(p,d,k,fd=\text{“from”})) \}$$

Note: The quantities in these equations are the changes to *scheduled* flows due to *contingency gas* being called which increase the quantity shipped to the *hub* or decrease the quantity withdrawn from the *hub*. The latter quantities are negative, so must be multiplied by negative one.

This section relates to *contingency gas* usage producing positive changes in flows to the *hub* and negative changes in flows from the *hub*. The MAX() functions in the following equations extract either the positive or negative changes as required and convert it to a positive value.

(b) The charge payable by *Trading Participant* p for *gas day* d when *contingency gas* is called to decrease net *supply* to the *hub* is:

$$CGC(p,d) = CGPL(d) \times \{ \Sigma_{k\in SP} MAX(0, -1 \times CQ^S(p,d,k,fd=\text{“to”})) + \Sigma_{k\in SN} MAX(0, CQ^U(p,d,k, fd=\text{“from”})) + \Sigma_{k\in SP} MAX(0,CQ^S(p,d,k,fd=\text{“from”})) \}$$

Note: The quantities in these equations are the changes to *scheduled* flows due to *contingency gas* being called which decrease the quantity shipped to the *hub* or increase the quantity withdrawn from the *hub*. The former quantities are negative, so must be multiplied by negative one.

10.6A *Ad Hoc Charges* for *Contingency Gas* Resettlement

Explanatory Note

This clause describes how *AEMO* determines the amount payable by or to a *Trading Participant* where *AEMO* has determined under rule 449(3) that the *Trading Participant* has not provided the full quantity of *contingency gas* it was *scheduled* to deliver on a *gas day* and the *Trading Participant's deviation payments* or *deviation charges* do not fully account for the failure.

When *contingency gas* is called to increase supply to the *hub*:

(a) the amount to be refunded by the *Trading Participant* is an *ad hoc charge* in accordance with clause 10.6A(a) calculated by determining the undelivered *contingency gas quantity* (the *scheduled contingency gas quantity* less any negative *deviation quantities* for that *market facility* and flow direction, less the delivered *contingency gas quantity* determined by *AEMO*) and charging for this quantity at the difference between the *high contingency gas price* and the *deviation price* for a *long deviation quantity*.

When *contingency gas* is called to decrease supply to the *hub*:

(b) the amount to be refunded by the *Trading Participant* is an *ad hoc charge* in accordance with clause 10.6.A(b) calculated by determining the undelivered *contingency gas quantity* (the *scheduled contingency gas quantity* less any positive *deviation quantities* for that *market facility* and flow direction, less the delivered *contingency gas quantity* determined by *AEMO*) and paying for this quantity at the difference between the *low contingency gas price* and the *deviation price* for a *short deviation quantity*.

In each case, the *ad hoc charges* payable in respect of *contingency gas* resettlement will be distributed by way of *ad hoc payments* to other *Trading Participants* who are out of pocket as a result of the undelivered *contingency gas*, determined in accordance with clause 10.6B

See clause 10.8.2 for the calculation of *deviation quantities*.

(a) The *ad hoc charge* for *Trading Participant* p in relation to a *scheduled* quantity of *contingency gas* to increase supply to the *hub* on *gas day* d is:

AHC (p,d) = MAX(0, (CGPH(d) – PDevPT(p,d,k)) ×

$\{ \Sigma_{k\in SP}$ [MAX(0, (MAX(0, CQ^S(p,d,k, fd="to")) - MAX(0, -1 × DQT(p,d,k)) - MAX(0,CQP^S (p,d,k fd="to"))))]

+ $\Sigma_{k\in SP}$ [MAX(0,(MAX(0, -1 × CQ^S(p,d,k,fd="from")) - MAX(0, -1 × DQF(p,d,k)) - MAX(0, -1 × CQP^S (p,d,k,fd="from"))))]

+ $\Sigma_{k\in SN}$ [MAX(0, (MAX(0, -1 × CQ^U(p,d,k,fd="from")) - MAX(0, -1 × DQF(p,d,k)) - MAX(0, -1 × CQP^U (p,d,k,fd="from"))))] })

(b) The *ad hoc charge* for *Trading Participant* p in relation to a *scheduled* quantity of *contingency gas* to decrease supply to the *hub* on *gas day* d is:

AHC(p,d) = MAX(0, (PDevNT(p,d,k) – CGPL(d)) ×

$\{ \Sigma_{k\in SP}$ [MAX(0, (MAX(0, -1 × CQ^S(p,d,k, fd="to")) - MAX(0, DQT(p,d,k)) - MAX(0, -1 × CQP^S (p,d,k fd="to"))))]

+ $\Sigma_{k\in SP}$ [MAX(0, (MAX(0, CQ^S(p,d,k, fd="from")) - MAX(0, DQF(p,d,k)) - MAX(0, CQP^S (p,d,k fd="from"))))]

+ $\Sigma_{k\in SN}$ [MAX(0, (MAX(0, CQ^U(p,d,k, fd="from")) - MAX(0, DQF(p,d,k)) - MAX(0, CQP^U (p,d,k fd="from"))))] })

10.6B *Ad Hoc Payments* for *Contingency Gas* Resettlement

(a) If an *ad hoc charge* is payable by a *Trading Participant* under clause 10.6A, an equivalent amount is to be distributed to *Trading Participants* at the relevant *hub* by way of *ad hoc payments* determined under paragraph (b).

(b) The *ad hoc payment* for *Trading Participant* p on *gas day* d depends on the *Trading Participant's deviation quantity* (whether short or long) and the nature of the relevant *contingency gas requirement* (whether for increased or decreased supply to the *hub*), and is determined as follows:

(i) Calculate the Trading Participant's short deviation quantity for the relevant hub and gas day (SDQ(p,d)):

$$SDQ(p,d) = \Sigma_{k \in SP} [MAX(0, -1 \times DQT(p,d,k))] + \Sigma_{k \in SP} [MAX(0, -1 \times DQF(p,d,k))] + \Sigma_{k \in SN} [MAX(0, -1 \times DQF(p,d,k))]$$

(ii) Calculate the Trading Participant's long deviation quantity for the relevant hub and gas day (LDQ(p,d)):

$$LDQ(p,d) = \Sigma_{k \in SP} [MAX(0, DQT(p,d,k))] + \Sigma_{k \in SP} [MAX(0, DQF(p,d,k))] + \Sigma_{k \in SN} [MAX(0, DQF(p,d,k))]$$

(iii) *Trading Participant's ad hoc payment* where *contingency gas* was required to increase supply to the *hub*:

$$AHP(p,d) = MAX (0, MIN(PDevNT(p,d,k) - RDevN(d), \sum_p AHC(p,d) / \sum_p SDQ(p,d)) \times SDQ(p,d))$$

Where:

RDevN(d) is the revised *deviation price* for a *short deviation quantity*, as described below; and

AHC is the *ad hoc charge* payable under clause 10.6A.

If a *Trading Participant* does not deliver *contingency gas* as *scheduled*, this may result in a requirement to schedule additional *contingency gas*.RDevN(d) is determined by adjusting the *high contingency gas price* and recalculating the *deviation price* applicable to a *short deviation quantity* on the *gas day*. The adjusted *high contingency gas price* excludes any additional *contingency gas* that was *scheduled* to replace the *contingency gas* that was not delivered.

(iv) *Trading Participant's ad hoc payment* where *contingency gas* was required to decrease supply to the *hub*:

$$AHP(p,d) = MAX (0, MIN(RDevP(d) - PDevPT(p,d,k), \sum_p AHC(p,d) / \sum_p LDQ(p,d)) \times LDQ(p,d))$$

Where:

RDevP(d) is the revised *deviation price* for a *long deviation quantity*, as described below; and

AHC is the *ad hoc charge* payable under clause 10.6A.

If a *Trading Participant* does not deliver *contingency gas* as *scheduled*, this may result in a requirement to *schedule* additional *contingency gas*. RDevP(d) is determined by adjusting the *low* *contingency gas price* and recalculating the *deviation price* applicable to a *long deviation quantity* on the *gas day*. The adjusted *low contingency gas price* excludes any additional *contingency gas* that was *scheduled* to replace the *contingency gas* that was not delivered.

10.7 Market Operator Service

Explanatory Note

This clause describes how *AEMO* determines the amount payable to an *STTM Shipper* for the provision of *MOS* or *overrun MOS* at a *hub* for the purposes of *rule* 461(2)(d), and the amounts payable either to or by an *STTM Shipper* for the restoration of *MOS gas* for the purposes of *rule* 461(2)(e).

The amount payable to an *STTM Shipper* for the provision of *MOS* or *overrun MOS* is determined in accordance with clauses 10.7.1 to 10.7.3 by:

(a) determining the price for *overrun MOS* for increased or decreased flows to the *hub* (as applicable) for each *STTM pipeline*, where:

(i) if no *MOS* is allocated to *MOS providers* under *MOS increase offers* or *MOS decrease offers* (as applicable), the price for *overrun MOS* is zero; or

(ii) if the quantity of *MOS* allocated to *MOS providers* under *MOS increase offers* or *MOS decrease offers* (as applicable) is greater than zero but less than the relevant MOS estimate determined by *AEMO* in accordance with clause 5.2, the price for *overrun MOS* is the weighted average of the *MOS price* of each *price step* in the applicable *MOS stack* to which *MOS* is allocated; or

(iii) if the quantity of *MOS* allocated to *MOS providers* under *MOS increase offers* or *MOS decrease offers* (as applicable) is greater than the relevant MOS estimate determined by *AEMO* in accordance with clause 5.2, the price for *overrun MOS* is equal to the *MOS price* of the highest priced *price step* in the applicable *MOS stack* to which *MOS* is allocated; and

(b) determining the amount payable to an *STTM Shipper* for the provision of *MOS* under one or more *MOS increase offers* or *MOS decrease offers* using a pay-as-bid principle, with the quantity allocated to each of the *STTM Shipper's price steps* multiplied by the price of that *price step*; and

(c) determining the amount payable to an *STTM Shipper* for the provision of *overrun MOS* on each *STTM pipeline* by multiplying the relevant price for *overrun MOS* by the quantity of *overrun MOS* allocated to the *STTM Shipper* on that *STTM pipeline*.

The amount payable to an *STTM Shipper* for the restoration of *MOS gas* provided at a *hub* on *gas day* d-2 is determined in accordance with clause 10.7.4 by multiplying the *ex ante market price* for *gas day* d by the quantity of *MOS* allocated to that *STTM Shipper* under a *MOS increase offer* or as *overrun MOS* for increased flow to the *hub* on *gas day* d-2.

The amount payable by an *STTM Shipper* for the restoration of *MOS gas* provided at a *hub* on *gas day* d-2 is determined in accordance with clause 10.7.4 by multiplying the *ex ante market price* for *gas day* d by the quantity of *MOS* allocated to that *STTM Shipper* under a *MOS decrease offer* or as *overrun MOS* for decreased flow to the *hub* on *gas day* d-2.

10.7.1 Price for overrun MOS for increased flows to the hub

(a) The total *MOS* increased gas flows to the *hub* allocated under *MOS increase offers* on *market facility* k ∈ SP is:

$$TCMIQ(d,k) = \Sigma_p \Sigma_{m(k)} \Sigma_j\ MOSAI^S(p,d,m(k),j)$$

(b) The value of ORPI(d,k), the price for *overrun MOS* for increased gas flows to the *hub* for *market facility* k ∈ SP and *gas day* d, is determined as:

If TCMIQ(d,k) = 0

$$ORPI(d,k) = 0$$

If TCMIQ(d,k) > 0 and TCMIQ(d,k) ≤ MOSRI(d,k) then

$$ORPI(d,k) = \{\Sigma_p\ \Sigma_{m(k)}\ \Sigma_j\ MOSIC^S(p,d,m(k),j) \times MOSAI^S(p,d,m(k),j)\ \} / TCMIQ(d,k)$$

If TCMIQ(d,k) > 0 and TCMIQ(d,k) > MOSRI(d,k) then

ORPI(d,k) is the maximum price $MOSIC^S(p,d,m(k),j)$ of any step j in the *MOS increase stack* for any *MOS increase offer* m(k) for any *Trading Participant* p which is allocated *MOS* ($MOSAI^S(p,d,m(k),j) > 0$) on *gas day* d.

10.7.2 Price for overrun MOS for decreased flows to the hub

(a) The total *MOS* decrease gas flows to the *hub* allocated under *MOS decrease offers* on *market facility* k ∈ SP is:

$$TCMDQ(d,k) = \Sigma_p \Sigma_{m(k)} \Sigma_j\ MOSAD^S(p,d,m(k),j)$$

(b) The value of ORPD(d,k), the price for *overrun MOS* for decreased gas flows to the *hub* for *market facility* k ∈ SP and *gas day* d, is determined as:

If TCMDQ(d,k) = 0

$$ORPD(d,k) = 0$$

If TCMDQ(d,k) > 0 and TCMDQ(d,k) ≤ MOSRD(d,k) then

$$ORPD(d,k) = \{\Sigma_p\ \Sigma_{m(k)}\ \Sigma_j\ MOSDC^S(p,d,m(k),j) \times MOSAD^S(p,d,m(k),j)\ \} / TCMDQ(d,k)$$

If TCMDQ(d,k) > 0 and TCMDQ(d,k) > MOSRD(d,k) then

ORPD(d,k) is the maximum price $MOSDC^S(p,d,m(k),j)$ of any step j in the *MOS decrease stack* for any *MOS decrease offer* m(k) for any *Trading Participant* p which is allocated *MOS* ($MOSAD^S(p,d,m(k),j) > 0$) on *gas day* d.

10.7.3 MOS settlement

(a) The payment to *Trading Participant* p for *MOS* provided to the *hub* under one or more *MOS increase offers* or *MOS decrease offers* for *gas day* d is:

$$MCP(p,d) = \Sigma_{k\in SP}\ \Sigma_{m(k)}\ MOSFP(p,d,m(k)) + \Sigma_{k\in SP}\ \Sigma_{m(k)}\ \Sigma_j\ (MOSIC^S(p,d,m(k),j) \times MOSAI^S(p,d,m(k),j)) + \Sigma_{k\in SP}\ \Sigma_{m(k)}\ \Sigma_j\ (MOSDC^S(p,d,m(k),j) \times MOSAD^S(p,d,m(k),j))$$

Note: This payment includes a fixed charge for *MOS increase offers* and *MOS decrease offers* included in a *MOS stack* (which will be zero at market commencement) and payments for *MOS* increases and decreases under *MOS increase offers* and *MOS decrease offers* based on the quantities allocated to those *MOS increase offers* and *MOS decrease offers*.

(b) The payment to *Trading Participant* p for *overrun MOS* provided to the *hub* for *gas day* d is:

$$MOP(p,d) = \Sigma_{k\in SP}(ORPI(d,k) \times MAX(0,\Sigma_{c(k)}\{ OMAQ^S(p,d,ct(k)) + OMAQ^S(p,d,cf(k)) \})) + \Sigma_{k\in SP}\ (ORPD(d,k) \times -1\times MIN(0, \Sigma_{c(k)}\{ OMAQ^S(p,d,ct(k)) + OMAQ^S(p,d,cf(k)) \}))$$

Note: *MOS* overrun payments for increases and decreases under *registered trading rights* are based on allocations for *overrun MOS* to *registered* contracts which will be associated by *AEMO* in settlement with the *registered trading right* of the *contract holder* for that *registered* contract. The overrun price for increases is applied to quantities that increase net flow to the *hub* while the overrun prices for decreases is applied to quantities that decrease net flow to the *hub*.

10.7.4 Restoration of MOS gas

(a) The *MOS* cash-out payment for the *hub* for *Trading Participant* p as a *MOS provider* at the *gas day* d price for *MOS* gas provided on *gas day* d-2 is:

$$MCCP(p,d) = HP(d) \times \Sigma_{k\in SP}\ [\Sigma_{ct(k)}MAX(0,MAQ^S(p,d-2,ct(k))) + \Sigma_{cf(k)}\ MAX(0,MAQ^S(p,d-2,cf(k)))]$$

(b) The *MOS* cash-out charge for the *hub* for *Trading Participant* p as a *MOS provider* at the *gas day* d price for *MOS* gas provided on *gas day* d-2 is:

$$MCCC(p,d)=HP(d)\times\Sigma_{k\in SP}\ [\Sigma_{cf(k)}MAX(0,-1\times MAQ^S(p,d-2,cf(k))) + \Sigma_{ct(k)}MAX(0, -1\times MAQ^S(p,d-2,ct(k)))]$$

(c) The *MOS* cash-out payment for the *hub* for *Trading Participant* p for providing *overrun MOS* at the *gas day* d price for *MOS gas* provided on *gas day* d-2 is:

$$MCOP(p,d) = HP(d)\times\Sigma_{k\in SP}[\Sigma_{ct(k)}MAX(0,OMAQ^S(p,d-2,ct(k))) + \Sigma_{cf(k)}MAX(0,OMAQ^S(p,d-2,cf(k)))]$$

(d) The *MOS* cash-out charge for the *hub* for *Trading Participant* p for providing *overrun MOS* at the *gas day* d price for *MOS* gas provided on *gas day* d-2 is:

$$MCOC(p,d)=HP(d)\times\Sigma_{k\in SP}[\Sigma_{cf(k)}MAX(0, -1\times OMAQ^{S}(p,d-2,cf(k))) + \Sigma_{ct(k)} MAX (0, -1\times OMAQ^{S}(p,d-2,ct(k)))]$$

Note: Whether a payment or charge applies depends on whether the change in net gas allocated to flow to the *hub* is positive or negative.

10.7.5 Net MOS settlement

(a) The *MOS* payment to *Trading Participant* p for *gas day* d for the *hub* is:

$$MosP(p,d) = MCP(p,d) + MOP(p,d) + MCCP(p,d) + MCOP(p,d)$$

(b) The *MOS* charge on *Trading Participant* p for *gas day* d for the *hub* is:

$$MosC(p,d) = MCCC(p,d) + MCOC(p,d)$$

10.8 Deviations

Explanatory Note

This clause describes how AEMO determines the *deviation payment* and *deviation charge* for a *Trading Participant* at a *hub* for the purposes of *rule* 461(2)(g). They are calculated in accordance with clauses 10.8.1 to 10.8.3 by:

(a) calculating the *modified market schedule quantity* for the *Trading Participant* for each *STTM facility* and flow direction, and the *hub*, being the aggregate of the relevant:

(i) *market schedule quantities*; and

(ii) allocations of *MOS* and *overrun MOS*; and

(iii) *scheduled* quantities of *contingency gas;* and

(iv) *market schedule variations*; and

(b) calculating *deviation quantities* for the *Trading Participant* for each *STTM facility* and flow direction, and the *hub*, being the difference between the relevant *modified market schedule quantity* and the corresponding *allocation quantity*; and

(c) calculating payments or charges for each *deviation quantity* using *deviation prices*, where:

(i) [Deleted]

(ii) *deviation prices* are calculated by reference to:

(A) the *ex ante market price*; and

(B) the *ex post imbalance price*; and

(C) the applicable *high contingency gas price* or *low contingency gas price* (if any); and

(D) the applicable MOS increase cost or MOS decrease cost, where a MOS increase cost will apply if the net *MOS gas* requirement at the hub was positive (increase MOS), and a MOS decrease cost will apply if the net *MOS gas* requirement at the hub was negative (decrease MOS);

for the *gas day*; and

(iii) an exception is made where an *administered price cap state* applies by reason of *material involuntary curtailment*, in which case *deviation charges* are priced at the *administered price cap* and *deviation payments* are priced at the *ex ante market price* for the *gas day*.

10.8.1 Modified market schedule quantities

Note: The *modified market schedule quantity* used in settlements for *STTM Shippers* and *STTM Users* reflects what *AEMO* expects to have *scheduled* if that *STTM Shipper* or *STTM User* is to have no *deviation payments* or charges.

(a) The *modified market schedule quantity* for *Trading Participant* p on *gas day* d in its role as an *STTM Shipper* on *market facility* $k \in SP$ with flow direction fd is:

For fd = 'from':[1]

$$MMSQ^S(p,d,k,fd) = \Sigma_{cf(k)} \{MQ^S(p,d,cf(k)) - MAQ^S(p,d,cf(k)) - OMAQ^S(p,d,cf(k))\} + CQ^S(p,d,k,fd) + FSC(p,d,k,fd) + CSC(p,d,k,fd)$$

For fd = 'to':

$$MMSQ^S(p,d,k,fd) = \Sigma_{ct(k)} \{MQ^S(p,d,ct(k)) + MAQ^S(p,d,ct(k)) + OMAQ^S(p,d,ct(k))\} + CQ^S(p,d,k,fd) + FSC(p,d,k,fd) + CSC(p,d,k,fd)$$

(b) The *modified market schedule quantity* for *Trading Participant* p on *gas day* d in its role as an *STTM User* on *market facility* $k \in SN$ with flow direction fd is:

For fd = 'from':

$$MMSQ^U(p,d,k,fd) = \Sigma_{cf(k)} \{MQ^U(p,d,cf(k))\} + CQ^U(p,d,k,fd) + FSC(p,d,k,fd) + CSC(p,d,k,fd)$$

For fd = 'to' there cannot be a *modified market schedule quantity* as *STTM Users* can only withdraw from the *hub* so:

$$MMSQ^U(p,d,k,fd) = 0$$

(c) The terms $MMSQ^S(p,d,k,fd)$ and $MMSQ^U(p,d,k,fd)$ may be positive or negative.

1 As positive *MOS* flow for an *STTM Shipper* flowing gas from the *hub* implies reduced flow from the *hub*, a positive *MOS* flow must decrease the *modified market schedule quantity* for that *STTM Shipper*.

10.8.2 Deviation quantities

(a) The total GJ *deviation quantity* for *Trading Participant* p for its withdrawals from the *hub* as an *STTM User* on *market facility* $k \in SN$ on *gas day* d is:

$$DQF(p,d,k) = MMSQ^{U}(p,d,k,fd=\text{"from"}) - \Sigma_{cf(k)} AQ^{U}(p,d,cf(k))$$

(b) The total GJ *deviation quantity* for *Trading Participant* p for its withdrawals from the *hub* as an *STTM Shipper* on *market facility* $k \in SP$ on *gas day* d is:

$$DQF(p,d,k) = MMSQ^{S}(p,d,k,fd=\text{"from"}) - \Sigma_{cf(k)} AQ^{S}(p,d,cf(k))$$

(c) The total GJ *deviation quantity* for *Trading Participant* p for its *supply* to the *hub* as an *STTM Shipper* on *market facility* $k \in SP$ on *gas day* d is:

$$DQT(p,d,k) = \Sigma_{ct(k)} AQ^{S}(p,d,ct(k)) - MMSQ^{S}(p,d,k,fd=\text{"to"})$$

(d) The total GJ *deviation quantity* for *Trading Participant* p for its *supply* to the *hub* as an *STTM User* on *market facility* $k \in SN$ on *gas day* d is by definition:

$$DQT(p,d,k) = 0$$

(e) The values of DQF(p,d,k) and DQT(p,d,k) may be positive or negative.

10.8.3 [Deleted]

10.8.4 [Deleted]

10.8.4A MOS increase cost

(a) The MOS increase cost for *gas day* d is:

If $(\Sigma_p \Sigma_{k \in SP} \Sigma_{cf(k)} (MAQ^{S}(p,d,cf(k)) + OMAQ^{S}(p,d,cf(k))) + \Sigma_p \Sigma_{k \in SP} \Sigma_{ct(k)} (MAQ^{S}(p,d,ct(k)) + OMAQ^{S}(p,d,ct(k)))) > 0$ then

$$MOSXI(d) = [\Sigma_p \Sigma_{k \in SP} \Sigma_{m(k)} \Sigma_j (MOSIC^{S}(p,d,m(k),j) \times MOSAI^{S}(p,d,m(k),j)) + \Sigma_p \Sigma_{k \in SP}(ORPI(d,k) \times \Sigma_{c(k)}\{ MAX(0,OMAQ^{S}(p,d,ct(k))) + MAX(0,OMAQ^{S}(p,d,cf(k))) \}) + \Sigma_p MCCP(p,d+2) + \Sigma_p MCOP(p,d+2)] \; / \; \Sigma_p \Sigma_{k \in SP} \Sigma_{c(k)}\{ MAX(0,MAQ^{S}(p,d,ct(k))) + MAX(0,MAQ^{S}(p,d,cf(k))) + MAX(0,OMAQ^{S}(p,d,ct(k))) + MAX(0,OMAQ^{S}(p,d,cf(k))) \}$$

ELSE

$$MOSXI(d) = NULL$$

Note: The MOS increase cost is only calculated if the net *MOS gas* requirement at the hub is positive (increase MOS). The MOS increase cost is the sum of *MOS* and *overrun MOS* payments for *gas day* d, and *MOS* cash-out payments from *gas day* d+2 (for *MOS* provided on *gas day* d) for all increase MOS allocated on *gas day* d at the hub, divided by the quantity of all increase MOS allocated on *gas day* d at the hub.

10.8.4B MOS decrease cost

(a) The MOS decrease cost for *gas day* d is:

If $(\Sigma_p \Sigma_{k\in SP} \Sigma_{cf(k)} (MAQ^S(p,d,cf(k)) + OMAQ^S(p,d,cf(k))) + \Sigma_p \Sigma_{k\in SP} \Sigma_{ct(k)} (MAQ^S(p,d,ct(k)) + OMAQ^S(p,d,ct(k)))) < 0$ then

$MOSXD(d) = [\Sigma_p \Sigma_{k\in SP} \Sigma_{m(k)} \Sigma_j (MOSDC^S(p,d,m(k),j) \times MOSAD^S(p,d,m(k),j)) + \Sigma_p \Sigma_{k\in SP} (ORPD(d,k) \times (-1 \times \Sigma_{c(k)}\{ MIN(0, OMAQ^S(p,d,ct(k))) + MIN(0, OMAQ^S(p,d,cf(k))) \})) - \Sigma_p MCCC(p,d+2) - \Sigma_p MCOC(p,d+2)] / \Sigma_p\Sigma_{k\in SP} \Sigma_{c(k)}\{ MIN(0,MAQ^S(p,d,ct(k))) + MIN(0,MAQ^S(p,d,cf(k))) + MIN(0, OMAQ^S(p,d,ct(k))) + MIN(0, OMAQ^S(p,d,cf(k))) \}$

ELSE

$MOSXD(d) = NULL$

Note: The MOS decrease cost is only calculated if the net *MOS gas* requirement at the hub is negative (decrease MOS). The MOS decrease cost is the sum of *MOS* and overrun *MOS* payments for *gas day* d and *MOS* cash-out charges from *gas day* d+2 (for *MOS* provided on *gas day* d) for all decrease MOS allocated on *gas day* d at the hub, divided by the quantity of all decrease MOS allocated on *gas day* d at the hub.

The MOS decrease cost may be a positive or negative value.

10.8.5 Deviation prices

(a) For *Trading Participant* p with a *long deviation quantity* for withdrawals from the *hub* (i.e. lower withdrawal than expected) on *market facility* k on *gas day* d, the deviation price is:

If DPFlag(d) = 0

IF CGPH(d) ≥ 0

PDevPF(p,d,k) = MAX(MINP(d), MIN(MAXP(d), HP(d), IHP(d), CGPL(d)))

ELSE

PDevPF(p,d,k) = MAX(MINP(d), MIN(MAXP(d), HP(d), IHP(d), CGPL(d), MOSXD(d)))

If DPFlag(d) = 1

PDevPF(p,d,k) = HP(d)

(b) For *Trading Participant* p with a *short deviation quantity* for withdrawals from the *hub* (i.e. higher withdrawal than expected) on *market facility* k on *gas day* d, the deviation price is:

If DPFlag(d) = 0

IF CGPL(d) ≥ 0

PDevNF(p,d,k) = MIN(MAXP(d), MAX(MINP(d), HP(d), IHP(d), CGPH(d)))

ELSE

PDevNF(p,d,k) = MIN(MAXP(d), MAX(MINP(d), HP(d), IHP(d), CGPH(d), MOSXI(d)))

If DPFlag(d) = 1

PDevNF(p,d,k)= MAXP(d)

(c) For *Trading Participant* p with a *long deviation quantity* for gas supplied to the *hub* (i.e. higher *supply* than expected) on *market facility* k on *gas day* d, the deviation price is:

If DPFlag(d) = 0

IF CGPH(d) ≥ 0

PDevPT(p,d,k) = MAX(MINP(d), MIN(MAXP(d), HP(d), IHP(d), CGPL(d)))

ELSE

PDevPT(p,d,k)= MAX(MINP(d), MIN(MAXP(d), HP(d), IHP(d), CGPL(d), MOSXD(d)))

If DPFlag(d) = 1

PDevPT(p,d,k)= HP(d)

(d) For *Trading Participant* p with a *short deviation quantity* for gas supplied to the *hub* (i.e. lower supply than expected) on *market facility* k on *gas day* d, the *deviation price* is:

If DPFlag(d) = 0

IF CGPL(d) ≥ 0

PDevNT(p,d,k) = MIN(MAXP(d), MAX(MINP(d), HP(d), IHP(d), CGPH(d)))

ELSE

PDevNT(p,d,k)= MIN(MAXP(d) , MAX(MINP(d), HP(d), IHP(d), CGPH(d), MOSXI(d)))

If DPFlag(d) = 1

PDevNT(p,d,k)= MAXP(d)

10.8.6 [Deleted]

10.8.7 [Deleted]

10.8.8 [Deleted]

10.8.9 [Deleted]

10.8.10 [Deleted]

10.8.11 Deviation payments and charges

(a) The *deviation payment* for *Trading Participant* p for a *long deviation quantity* in withdrawals from the *hub* (i.e. lower withdrawal than expected) on *market facility* k on *gas day* d is:

$$DevPFA(p,d,k) = MAX(0 , DQF(p,d,k)) \times PDevPF(p,d,k)$$

(b) The *deviation charge* for *Trading Participant* p for a *short deviation quantity* in withdrawals from the *hub* (i.e. higher withdrawal than expected) on *market facility* k on *gas day* d is:

$$DevNFA(p,d,k) = MAX(0, -1 \times DQF(p,d,k)) \times PDevNF(p,d,k)$$

(c) The *deviation payment* for *Trading Participant* p for a *long deviation quantity* in gas supplied to the *hub* (i.e. higher supply than expected) on *gas day* d is:

$$DevPTA(p,d,k) = MAX(0 , DQT(p,d,k)) \times PDevPT(p,d,k)$$

(d) The *deviation charge* for *Trading Participant* p for a *short deviation quantity* in gas supplied to the *hub* (i.e. lower supply than expected) on *gas day* d is:

$$DevNTA(p,d,k) = MAX(0 , -1 \times DQT(p,d,k)) \times PDevNT(p,d,k)$$

(e) The total *deviation payment* to *Trading Participant* p for the *hub* for *gas day* d is:

$$DevP(p,d) = \Sigma_k\{DevPFA(p,d,k) + DevPTA(p,d,k)\}$$

(f) The total *deviation charge* to *Trading Participant* p for the *hub* for *gas day* d is:

$$DevC(p,d) = \Sigma_k\{ DevNFA(p,d,k) + DevNTA(p,d,k)\}$$

10.9 Capacity Settlement

Explanatory Note

This clause describes how *AEMO* determines the *capacity payment* and *capacity charge* for a *Trading Participant* at a *hub* for the purposes of *rule* 461(2)(f). They are calculated in accordance with clauses 10.9.1 to 10.9.3 by:

(a) determining the total quantity of capacity traded across all *Trading Participants* on each *STTM facility*, being the lesser of:

(i) the total quantity of gas specified in *STTM facility allocations* for that *STTM facility* in respect of *registered facility services* for *as available capacity* (net of allocations of *MOS*); and

(ii) the total quantity of gas specified in *ex ante offers* submitted in respect of *registered facility services* for *firm capacity* on that *STTM facility* but not included in *STTM facility allocations* for those *registered facility services* (net of allocations of *MOS* and capped if necessary by the *capacity limit* of relevant *registered trading rights*); and

(b) for each *STTM facility* at the *hub*, multiplying:

(i) the *capacity charge* rate for that *STTM facility*, which is calculated by adjusting the relevant *capacity price* by the ratio of the total quantity of capacity traded on that *STTM facility* to the quantity referred to in paragraph (a)(i); by

(ii) the quantity of gas allocated to a *Trading Participant* in respect of *registered facility services* for *as available capacity* (net of allocations of *MOS*),

the sum of those amounts being the *capacity charge* for that *Trading Participant* at that *hub*; and

(c) for each *STTM facility* at the *hub,* multiplying:

(i) the *capacity payment* rate for that *STTM facility*, which is calculated by adjusting the relevant *capacity price* by the ratio of the total quantity of capacity traded on that *STTM facility* to the quantity referred to in paragraph (a)(ii); by

(ii) the quantity of gas specified in *ex ante offers* submitted by a *Trading Participant* in respect of *registered facility services* for *firm capacity* but not allocated to that *Trading Participant* (net of allocations of *MOS* and capped if necessary by the *capacity limit* of relevant *registered trading rights*),

the sum of those amounts being the *capacity payment* for that *Trading Participant* at that *hub*.

10.9.1 Determining levels of trade

Note: *Capacity charge*s to *STTM Shippers* are based on the quantity of gas allocated to *registered trading rights* with *as available capacity* (excluding *MOS* allocations and *overrun MOS* allocations). *Capacity payments* to *STTM Shippers* are based on the quantity of gas not used from *registered trading rights* with *firm capacity* – being the difference between the gas offered and the gas actually flowed (excluding *MOS* allocations and *overrun MOS* allocations) on those *registered trading rights*. *MOS* allocations and *overrun MOS* allocations are removed because they are an allocation of actual *pipeline* flows and cannot cause an *STTM Shipper* with *firm capacity* to fail to access its *pipeline* capacity.

(a) The effective *allocated quantity* of gas supplied to the *hub* (based on *STTM facility allocations*) by *Trading Participant* p on *gas day* d on *registered trading right* ct(k) on *market facility* $k \in SP$ is:

$$EAQ^S(p,d,ct(k)) = MAX(0, AQ^S(p,d,ct(k)) - MAQ^S(p,d,ct(k)) - OMAQ^S(p,d,ct(k)))$$

Note: The effective *allocated quantity* is not limited to the capacity of the *registered trading right*. This ensures that a *Trading Participant* pays for the total quantity allocated to the *registered trading right*, even if that quantity is infeasible according to the data held by *AEMO*.

If the quantity was limited, a *Trading Participant* which understated its *capacity limit* would be able to flow gas beyond that limit at no *capacity charge*.

(b) The deemed gas offered on *firm capacity* to be supplied to the *hub* by *Trading Participant* p for *gas day* d on firm *registered trading right* ct(k) on *market facility* k∈SP is set to be:

$$FGO(p,d,ct(k)) = MIN(CAP(p,d,ct(k)), OQF^S(p,d,ct(k)))$$

Note: The *capacity limit* of the *registered trading right* is used to cap the quantity because while it is possible for the *capacity limit* to be less than the quantity offered, a *Trading Participant* will only be *scheduled* up to the *capacity limit* of the *registered trading right*.

(c) The total effective quantity of gas flowed via as available *registered trading rights* to the *hub* for *gas day* d on *market facility* k∈SP is:

$$TAFGQ(d,k) = \Sigma_p \Sigma_{ct(k)\in AH} EAQ^S(p,d,ct(k))$$

(d) The total quantity of gas offered on firm *registered trading rights* to the *hub* but not flowed (based on the effective *allocated quantity* of gas flowed) for *gas day* d on *market facility* k∈SP is:

$$TFGNQ(d,k) = \Sigma_p \Sigma_{ct(k)\in FH} MAX(0, FGO(p,d,ct(k)) - EAQ^S(p,d,ct(k)))$$

(e) The capacity quantity traded for *gas day* d on *market facility* k∈SP is:

$$CQT(d,k) = MIN(TAFGQ(d,k) , TFGNQ(d,k))$$

10.9.2 Capacity rates

(a) The effective *capacity charge* rate for as available *registered trading rights* on *gas day* d and *market facility* k∈SP is:

If TAFGQ(d,k) = 0

$$ECCA(d,k) = 0$$

Else

$$ECCA(d,k) = CP(d,k) \times CQT(d,k) / TAFGQ(d,k)$$

(b) The effective *capacity payment* rate for firm *registered trading rights* on *gas day* d and *market facility* k∈SP is:

If TFGNQ(d,k) = 0

$$ECPF(d,k) = 0$$

Else

$$ECPF(d,k) = CP(d,k) \times CQT(d,k) / TFGNQ(d,k)$$

Note: As the quantity of capacity traded cannot exceed the values of TAFGQ(d, k) or TFGNQ(d,k), these equations ensure that neither the *capacity charge* rate nor the *capacity payment* rate can exceed the value of the *capacity price*. If the quantity of gas allocated to *registered trading rights* for *as available capacity* equals the quantity of gas offered but not used for *registered trading rights* for *firm capacity,* each of the *capacity charge* rate and capacity payment rate will equal the *capacity price*.

10.9.3 Capacity payments and charges

(a) The *capacity charge* for *Trading Participant* p on *gas day* d for its gas flows on as available *registered trading rights* for the *hub* is:

$$SCC(p,d) = \Sigma_{k\in SP}\{\ ECCA(d,k) \times \ \Sigma_{ct(k)\in AH}\ EAQ^{S}(p,d,ct(k))\ \}$$

(b) The *capacity payment* for *Trading Participant* p on *gas day* d for firm *registered trading rights* offered but not utilised for the *hub* are:

$$SCP(p,d) = \Sigma_{k\in SP}\{\ ECPF(d,k) \times \Sigma_{ct(k)\in FH}\ MAX(0, FGO(p,d,ct(k)) - EAQ^{S}(p,d,ct(k))\ )\}$$

10.10 Settlement Shortfall Charges and Payments

Explanatory Note

This clause describes how *AEMO* determines the *settlement surplus payment* and *settlement shortfall charge* for a *Trading Participant* at a *hub* for the purposes of *rule* 464(2)(b)(i). They are calculated in accordance with clauses 10.10.1 to 10.10.5 by:

(a) calculating the settlement shortfall or settlement surplus for the *hub*, excluding *variation charges*; and

(b) calculating the *billing period deviation quantity* for the *Trading Participant* for the relevant *billing period*, which excludes any *gas days* for which an *administered price cap state* applied by reason of *material involuntary curtailment,* ; and

(c) allocating the settlement surplus in proportion to the *Trading Participant's* share of the total *billing period deviation quantity* for all *Trading Participants*, but subject to a cap equal to the *settlement surplus cap* multiplied by the *Trading Participant's billing period deviation quantity*; and

(d) allocating any settlement shortfall, any residual settlement surplus, and any surplus resulting from *variation charges*, to *Trading Participants* in proportion to their share of withdrawals from the *hub* in the *billing period*.

Fees are retained by *AEMO* and are not part of the settlement surplus or shortfall.

10.10.1 Shortfall or surplus

Note: The settlement surplus and shortfall allocation for a *hub* is not determined for each day but rather is determined for all the days in the *billing period* (or the *billing period* to date – for prudential purposes).

(a) The gross market income for the *hub* for the *billing period*, excluding participant fees and *variation charge*s, before settlement surplus and shortfall allocation, is:

$$GMI = \Sigma_{d\in BP}\Sigma_{p}\{MktC(p,d) + PFDCC(p,d) + CGC(p,d) + MosC(p,d) + DevC(p,d) + SCC(p,d) + AHC(p,d)\ \}$$

(b) The gross market outgoing for the *hub* for the *billing period*, excluding fees and *variation charges*, before settlement surplus and shortfall allocation, is:

$$GMO = \Sigma_{d\in BP}\Sigma_p\{MktP(p,d) + PFDCP(p,d) + CGP(p,d) + MosP(p,d) + DevP(p,d) + SCP(p,d) + AHP(p,d)\}$$

(c) The settlement surplus or shortfall for the *hub* for a *billing period* (excluding *variation charges*) is

$$NMB = GMI – GMO$$

(d) If NMB > 0 then the *hub* is in surplus (ignoring *variation charges*), while if NMB < 0 then the *hub* is in shortfall (ignoring *variation charges*).

10.10.2 Billing period deviation quantities

The *billing period deviation quantity* for *Trading Participant* p for the *hub* for the *billing period* is:

$$DQB(p) = \Sigma_{d\in BP}\ \{\ \Sigma_{k\in SN}\ [MAX(0,DQF(p,d,k)) \times LI(d,k) - MIN(0,DQF(p,d,k)) \times LD(d,k)] + \Sigma_{k\in SP}\ [MAX(0,DQF(p,d,k)) \times LI(d,k) - MIN(0,DQF(p,d,k)) \times LD(d,k) + MAX(0,DQT(p,d,k)) \times LI(d,k) - MIN(0,DQT(p,d,k)) \times LD(d,k)]\}$$

Where:

If DPFlag(d) = 0 then LI(d,k) = 1 and LD(d,k) = 1 for all $k\in SP$ and all $k\in SN$

if DPFlag(d) = 1 and NMB ≥ 0 then LI(d,k) = 1 and LD(d,k) = 1 for all $k\in SP$

if DPFlag(d) = 1 and NMB <0 then LI(d,k) = 0 and LD(d,k) = 1 for all $k\in SP$

if DPFlag(d) = 1 and NMB ≥ 0 then LI(d,k) = 1 and LD(d,k) = 1 for all $k\in SN$

if DPFlag(d) = 1 and NMB < 0 then LI(d,k) = 0 and LD(d,k) = 1 for all $k\in SN$

Note: The conditions with LI(d,k)=0 are the only conditions that materially protect *Trading Participants*. It means that if the market is in shortfall over a *billing period*, *Trading Participants* which deviate so as to increase net *supply* to the *hub* on a *gas day* on which *material involuntary curtailment* occurred do not fund that shortfall.

10.10.3 Surplus and shortfall allocation based on billing period deviations

The shortfall/surplus allocation based on deviations for *Trading Participant* p for the *hub* for the *billing period* is:

If $\Sigma_{p'}\ DQB(p') = 0$

$DVA(p) = 0$

Otherwise

$DVA(p) = MAX(0, MIN(AllCAP \times DQB(p) , NMB \times \{DQB(p) / (\Sigma_{p'} DQB(p')) \}))$

Note: The last term allocates NMB in proportion to deviations over the *billing period*, while the first term caps the allocation for positive NMB values at a rate of AllCAP, the $/GJ cap on positive allocations. This cap is intended to stop *Trading Participants* who deviated getting a high proportion of their *deviation charges* returned to them. Negative NMB values are allocated based on withdrawals in 10.10.4.

10.10.4 Residual surplus and shortfall allocation based on withdrawals

The shortfall/surplus allocation to *Trading Participant* p based on withdrawals for the *hub* for the *billing period* is:

If $\Sigma_{p'} \Sigma_{d\in BP} \{ \Sigma_{k\in SN}\Sigma_{cf(k)} AQ^U(p',d,cf(k)) + \Sigma_{k\in SP}\Sigma_{cf(k)} AQ^S(p',d,cf(k)) \} = 0$

$WDA(p) = 0$

Otherwise

$$WDA(p) = \{NMB - \Sigma_{p'} DVA(p') + \Sigma_d \Sigma_{p'} VarC(p',d)\} \times [\Sigma_{d\in BP} \{ \Sigma_{k\in SN}\Sigma_{cf(k)} AQ^U(p,d,cf(k)) + \Sigma_{k\in SP}\Sigma_{cf(k)} AQ^S(p,d,cf(k)) \} / (\Sigma_{p'} \Sigma_{d\in BP} \{ \Sigma_{k\in SN}\Sigma_{cf(k)} AQ^U(p',d,cf(k)) + \Sigma_{k\in SP}\Sigma_{cf(k)} AQ^S(p',d,cf(k)) \})]$$

10.10.5 Net surplus and shortfall payments and charges

(a) The *settlement surplus payment* to *Trading Participant* p for the *hub* for the *billing period* is:

$SSP(p) = MAX(0, DVA(p)) + MAX(0,WDA(p))$

(b) The *settlement shortfall charge* to *Trading Participant* p for the *hub* for the *billing period* is:

$SSC(p) = MAX(0, -1 \times DVA(p)) + MAX(0, -1 \times WDA(p))$

10.11 Determination and Payment of Claims

10.11.1 Interpretation

In this clause 10.11, an ***eligible price step*** for a *hub* and a *gas day* is:

(a) in the case of a claim made under *rule* 433(a) – a *price step* of an *ex ante offer* that:

(i) is *scheduled* for that *hub* and *gas day*; and

(ii) specifies a price that is greater than the *ex ante market price* for that *hub* on that *gas day*; or

(b) in the case of a claim made under *rule* 433(b) – a *price step* of a *contingency gas offer* that:

(i) is *scheduled* for that *hub* and *gas day*; and

(ii) specifies a price that is greater than the *high contingency gas price* for that *hub* on that *gas day*.

10.11.2 Amounts to be paid to Trading Participants

(a) The amount to be paid to a *Trading Participant* under *rule* 466(1) in respect of a claim made under *rule* 433(a) is:

(i) the minimum of:

(A) the estimated direct cost of supplying the gas, determined in accordance with clause 10.11.4; and

(B) the offered value of the gas supplied, determined in accordance with clause 10.11.5(a);

(ii) less the estimated total quantity of gas supplied under the *eligible price steps* (determined in accordance with clause 10.11.5(b)) multiplied by the *ex ante market price*.

(b) The amount to be paid to a *Trading Participant* under *rule* 466(1) in respect of a claim made under *rule* 433(b) is:

(i) the minimum of:

(A) the estimated direct cost of supplying the gas, determined in accordance with clause 10.11.4; and

(B) the offered value of the gas supplied, determined in accordance with clause 10.11.6(a);

(ii) less the estimated total quantity of gas supplied under the *eligible price steps* (determined in accordance with clause 10.11.6(b)) multiplied by the *high contingency gas price*.

(c) If a compensation amount determined under this clause is zero or a negative amount, then no compensation is to be paid.

10.11.3 Amounts to be paid by Trading Participants

(a) The amount to be paid by a *Trading Participant* under *rule* 466(1)(b) in respect of a claim under *rule* 433(a) is to be determined by apportioning the total amount to be paid by *AEMO* under *rule* 466(1)(a) between *Trading Participants* based on their *market schedule quantities* for withdrawals from the *hub* for the relevant *gas day*.

(b) The amount to be paid by a *Trading Participant* under *rule* 466(1)(b) in respect of a claim made under *rule* 433(b) is to be determined by:

(i) apportioning the amount equal to:

(A) the proportion of *contingency gas scheduled* that can be attributed to net participant short deviations, determined in accordance with paragraph (c);

(B) multiplied by the total amount to be paid by *AEMO* under *rule* 466(1)(a),

to *Trading Participants* in proportion to their *short deviation quantities* for the *gas day*; and

(ii) allocating any residual amount to be paid by *AEMO* under *rule* 466(1)(a) to *Trading Participants* in proportion to the quantity of gas withdrawn from the *hub* by each *Trading Participant* on the *gas day*.

(c) The proportion of *contingency gas scheduled* that can be attributed to net participant short deviations is:

(i) the maximum of zero and the lesser of:

(A) the quantity of *contingency gas scheduled* for increase in net *supply* to the *hub*; and

(B) the quantity of gross allocations of gas flow to the *hub* less the gross flows to the *hub* in the *ex ante market schedule*;

(ii) divided by the quantity of *contingency gas scheduled* for increase in net *supply* to the *hub*.

Note: This method of cost recovery first calculates what proportion of the total *contingency gas* called was due to the net short deviation of market participants. The corresponding proportion of the total compensation cost is recovered from those participants that had short deviations on the *gas day*. Any residual amount could be due to mis-estimation of the amount of CG needed, or CG called in multiple directions, or a *market administered scheduling state*, and this amount is smeared according to withdrawal quantities.

10.11.4 Direct cost of supplying gas

(a) The direct cost to a *Trading Participant* of supplying the quantity of gas that was supplied under *eligible price steps* (as determined under clause 10.11.5(b) or 10.11.6(b), as applicable) is the cost that is directly attributable to the *supply* of that quantity of gas, to be determined on the basis of written evidence provided by the relevant *Trading Participant*.

Note: Broadly this is expected to be based on *producer* and *haulage* contracts.

(b) For the avoidance of doubt, costs arising in related markets are not direct costs.

10.11.5 Offered value of gas supplied – Ex ante offer

(a) The offered value of gas supplied in relation to an *ex ante offer* is the sum of:

(i) the quantity of gas supplied under each *eligible price step*, determined in accordance with paragraph (d);

(ii) multiplied by the price specified in that *price step*.

(b) The total quantity of gas that is to be taken as having been supplied under *eligible price steps* in respect of an *ex ante offer* is:

(i) the estimated quantity of gas supplied under the *ex ante offer*, being the *market schedule quantity* for the applicable *registered trading right* $MQ^s(p,d,ct)$, less the maximum of:

(A) zero; and

(B) $\{ MMSQ^s(p,d,k,fd = \text{'to'}) / (\Sigma_{ct(k)}MQ^s(p,d,ct(k))) \} \times MQ^s(p,d,ct) - AQ^s(p,d,ct)$

Where:

$MMSQ^s(p,d,k,fd = \text{'to'})$ is the *modified market schedule quantity* for the relevant *Trading Participant* p, on the relevant *market facility* k for flow to the *hub*;

$\Sigma_{ct(k)}MQ^s(p,d,ct(k))$ is the total of all *market schedule quantities* for all of *Trading Participant* p's *registered trading rights* on the same *market facility* for flow to the *hub*; and

$AQ^s(p,d,ct)$ is the *registered facility service allocation* for the applicable *registered trading right*;

Note: This compares the *modified market schedule* with the allocation. Any shortfall in delivered gas is subtracted from the *ex ante market schedule*.

(ii) less the quantity *scheduled* in the ex ante market for the *price steps* in the *ex ante offer* for which the price was less than or equal to the ex-ante market price.

(c) If the quantity determined under paragraph (b) is zero or a negative amount, no gas is taken to have been supplied under *eligible price steps* in respect of an *ex ante offer*.

(d) If the quantity determined under paragraph (b) is a positive amount, that quantity must be allocated to the *eligible price steps* in the relevant *ex ante offer* in order of increasing price.

(e) If the relevant *Trading Participant* has also made a claim under *rule* 433(b) in relation to *contingency gas* provided for the same *gas day* and *market facility* for flow to the *hub*, the *dispute resolution panel* may reduce the quantity determined under paragraph (b)(i)(B) by an amount equal to amount determined in accordance with clause 10.11.6(b)(i)(B).

Note: Hence if the *Trading Participant's* allocation is less than its *modified market schedule*, the shortfall is first subtracted from the estimate of *contingency gas* supplied, and only the remainder will be subtracted from the ex-ante estimate.

10.11.6 Offered Value of Gas Supplied – Contingency gas offer

(a) The offered value of gas supplied in relation to a *contingency gas offer* is the sum of:

(i) the quantity of gas supplied under each *eligible price step*, determined in accordance with paragraph (d);

(ii) multiplied by the price specified in relation to that *price step*.

(b) The total quantity of gas that is to be taken as having been supplied under *eligible price steps* in respect of a *contingency gas offer* is:

(i) the estimated quantity of *contingency gas* supplied under the *contingency gas offer*, being, subject to paragraph (e):

(A) the quantity of *contingency gas scheduled* under the *contingency gas offer*;

(B) less the maximum of:

(1) zero; and

(2) for *contingency gas offers* by an *STTM Shipper* relating to flow direction to the *hub*, $MMSQ^s(p,d,k,fd = \text{'to'}) - \Sigma_{ct(k)}AQ^s(p,d,ct(k))$

(3) for *contingency gas offers* by an *STTM Shipper* relating to flow direction from the *hub*, $\Sigma_{ct(k)}AQ^s(p,d,ct(k)) - MMSQ^s(p,d,k,fd = \text{'from'})$

(4) for *contingency gas offers* by an *STTM User,* $\Sigma_{ct(k)}AQ^u(p,d,ct(k)) - MMSQ^u(p,d,k,fd = \text{'from'})$

Note: This compares the *modified market schedule* with the allocation. Any shortfall in delivered gas is subtracted from the estimate of contingency gas supplied. The estimate is also subject to adjustment based on other evidence, as set out in paragraph (e).

(ii) less the quantity *scheduled* for the *price steps* of the relevant *contingency gas offer* for which the price is less than or equal to the *high contingency gas price*.

(c) If the quantity determined under paragraph (b) is zero or a negative amount, no gas is taken to have been supplied under *eligible price steps* in respect of a *contingency gas offer*.

(d) If the quantity determined under paragraph (b) is a positive amount, that quantity must be allocated to the *eligible price steps* in the relevant *contingency gas offer* in order of increasing price.

(e) The *dispute resolution panel* may adjust a quantity determined under paragraph (b)(i) based on:

(i) evidence provided by the *Trading Participant* of the quantity of *contingency gas* actually provided; or

(ii) the fact that the *Trading Participant* has provided no such evidence,

but the adjusted quantity must not exceed the quantity of *contingency gas scheduled* under all *price steps* in the relevant *contingency gas offer*.

10.11.7 Dispute resolution panel to take all circumstances into account

(a) The *dispute resolution panel* may reduce (but may not increase) any amount of compensation calculated in accordance with the steps in this clause 10.11 by an amount that it considers to be equitable, taking into account the conduct of the *Trading Participant* and any other circumstances relating to the relevant offer or the claim.

(b) The *dispute resolution panel* may, under paragraph (a), reduce an amount of compensation to zero.

10.12 Settlement Statements

No requirements are specified for the purposes of *rule* 467.

CHAPTER 11 PRUDENTIAL REQUIREMENTS

11.1 Monitoring

(a) For the purpose of *rule* 484, *AEMO* must review its estimated exposure to each *Trading Participant* on each *business day*.

(b) A review under clause 11.1(a) must take into account the following unpaid amounts:

(i) from previous *billing periods* where there is a *settlement statement* but payment under that *settlement statement* is not yet due – the unpaid amount from the most recent *settlement statement* for the *billing period*; and

Note: This will include revised *settlement amounts* from previous months.

(ii) from previous *billing periods* where there is no *settlement statement* – an estimate of the unpaid amount for the *billing period* determined by *AEMO* using the prices, quantities and allocation data available at the time of the review; and

(iii) from the current *billing period*, up to and including the *gas day* before the review day – an estimate of the unpaid amount for the current *billing period* determined by *AEMO* using the prices, quantities and allocation data available at the time of the review.

Note: The review process is essentially a mini-settlement run for the month to date, combined with *settlement amounts* from the previous month. The review will take place after the allocations and prices from the previous *gas day* are available. The monthly amounts, such as the settlement shortfall or surplus allocation will be calculated as month to date balances. If *AEMO* has delayed the publication of the *ex post imbalance price* in accordance with *rule* 426(1A) the *provisional ex post imbalance price* may be used in the review.

11.2 Margin Calls

(a) For the purpose of *rule* 485, a *Trading Participant* must respond to a *margin call*:

(i) if the *margin call* is issued before 10:00 am on a *business day*, before 2:00 pm on the same *business day*;

(ii) otherwise, before 10:00 am on the next *business day*,

by either:

(iii) providing *AEMO* with a guarantee or bank letter of credit which complies with *rule* 479; or

(iv) prepaying an amount in cleared funds to *AEMO*.

(b) Where a *Trading Participant* responds to a *margin call* by prepaying an amount in accordance with clause 11.2(a)(iv), *AEMO* must apply the prepayment to obligations and liabilities for *billing periods* in chronological order, starting from the earliest relevant *billing period*.

CHAPTER 12 – TRANSITIONAL

12.1 MOS Periods

(a) Notwithstanding clause 5.1(a)(i), the first *MOS period* for a *hub* commences on the first *gas day* for the *hub* and ends on the last *gas day* of the *MOS Period* in place for all other *hubs* at the commencement of the *hub*.

(b) Deleted.

12.2 Market administered scheduling state

For the purposes of *rule* 430(2)(a)(i), the *ex ante market price* for each of the 30 *gas days* prior to the first *gas day* for a *hub* is taken to be $5/GJ.

12.3 Cumulative Price Threshold

For the purposes of clause 8.1, for each of the 7 *gas days* prior to the first *gas day* for a *hub*:

(a) the *ex ante market price* is taken to be $5/GJ; and

(b) the *ex post imbalance price* is taken to be $5/GJ; and

(c) the *high contingency gas price* and the *low contingency gas price* are taken not to have been determined by *AEMO*.

12.4 Deviation Quantities

The changes to clause 10.8.4 introduced by version 2 of the *STTM Procedures* do not affect any calculations relating to *gas days* prior to the effective date of version 2 of the *STTM Procedures*.