IN THE DISPUTE RESOLUTION PANEL AT MELBOURNE

(Constituted for a determination as to compensation under rule 226 of the National Gas Rules)

BETWEEN

AGL Sales Pty Limited (ABN 88 090 538 337) **(AGL)** &
Origin Energy Ltd (ABN 73 000 000 331) **(Origin)**

and

Australian Energy Market Operator Limited (ABN 94 072 010 327) **(AEMO)**

JOINT SUBMISSION TO THE DISPUTE RESOLUTION PANEL

A.   Glossary

1.   A number of terms and acronyms are used throughout this submission.

2.   Many of the terms used in these submissions are defined in the National Gas Rules (Version 2) **(NGR)**.[1]   For ease of reference these terms are italicised. Unless the context dictates otherwise, terms defined in the NGR have the same meaning in this submission as in the NGR.

3.   A reference to a 'rule' followed by a number means a provision in the NGR.

B.   Application

4.   Australian Energy Market Operator Limited **(AEMO)** investigated whether an *unintended scheduling result* occurred on 15 March 2010 in accordance with rule 218(1)(b)   and has determined that it did so occur.   Compensation may be payable from the *Participant compensation fund* **(PCF)** as a consequence of this *unintended scheduling result*.

5.   AGL and Origin are and were, at all material times, registered in the Victorian wholesale gas market as a *Market Participants*.

6.   Under rule 218(4), AGL and Origin may apply to the Dispute Resolution Panel **(DRP)** for a determination as to compensation as a consequence of the *unintended scheduling result*. The matters to be determined by the DRP are:

   (a)   whether an *unintended scheduling result* occurred;

   (b)   whether compensation is payable to either AGL or Origin;

   (c)   if so, the amount of compensation to be paid to AGL or Origin for their loss; and

   (d)   the manner and timing of payment of that compensation from the PCF.[2]

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[1] Being the applicable version at all material times.
[2] Rule 226(1).

C. AEMO and the Victorian Wholesale Gas Market

7. The Victorian wholesale gas market started in March 1999 and was designed to:

    - manage gas supply, demand and linepack of the Victorian Declared Transmission System (**DTS**);
    - allow *Market Participants* to buy and sell gas; and
    - set a daily gas price (ex post) for all trades.

8. The Victorian wholesale gas market was redesigned to an ex-ante market commencing February 2007 where gas prices are set at 6am, 10am, 2pm, 6pm and 10 pm.

9. The Victorian wholesale gas market covers the DTS, which is depicted in Figure 1.

Figure 1: Declared Transmission System
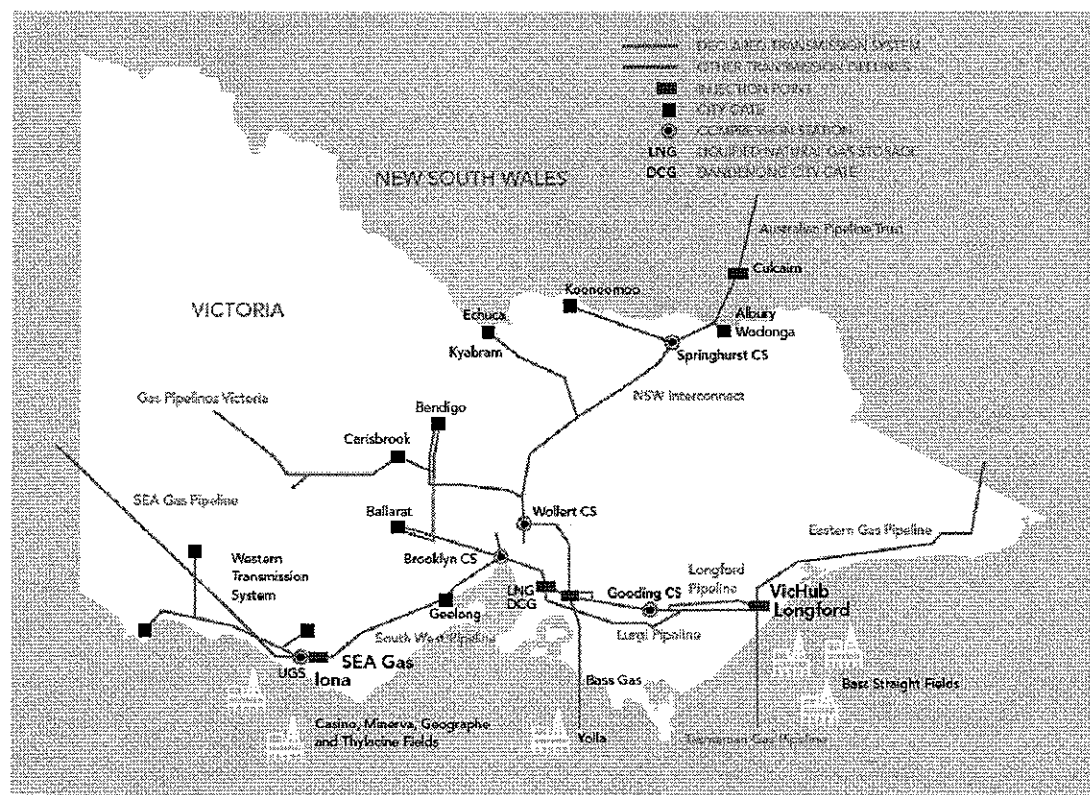
10. AEMO performs a number of functions in the Victorian wholesale gas market, including the following:

    - operate the DTS and operate and administer the market in accordance with the National Gas Law and the NGR;
    - establish and update system security standards for the DTS; and
   - operate the DTS so as to minimise the threats to system security.

D. The Regulatory Framework

11. The NGR governs access to natural gas pipeline services and broader elements of natural gas markets. As applied in Victoria, this includes the operation of the Victorian wholesale gas market.

12. The NGR:

- facilitates an efficient, competitive and reliable market;
- regulates the operation and administration of the market;
- regulates activities of participants in the market; and
- provides for access to the DTS in a way that ensures its security.

13. Participants can be directly or indirectly involved in the Victorian wholesale gas market. Those who are registered to trade gas, that is, to inject gas into, or withdraw gas from, the DTS are called *Market Participants*.

E. Operation of the Victorian Wholesale Gas Market

14. On any given gas day, *Market Participants* trade in the Victorian wholesale gas market based on the imbalances in the gas withdrawn by their respective customer loads and the gas injected into the DTS by each of them.

15. Gas scheduling is a process that AEMO conducts a number of times each gas day to provide hourly injection schedules for each *Market Participant* and schedules for any controllable withdrawals. The market clearing algorithm used in optimising each operating schedule minimises the cost of supplying gas to meet the forecast gas demand within the pipeline system security limits. Figure 2 highlights the key steps in this scheduling process.

Figure 2: Gas Scheduling Process
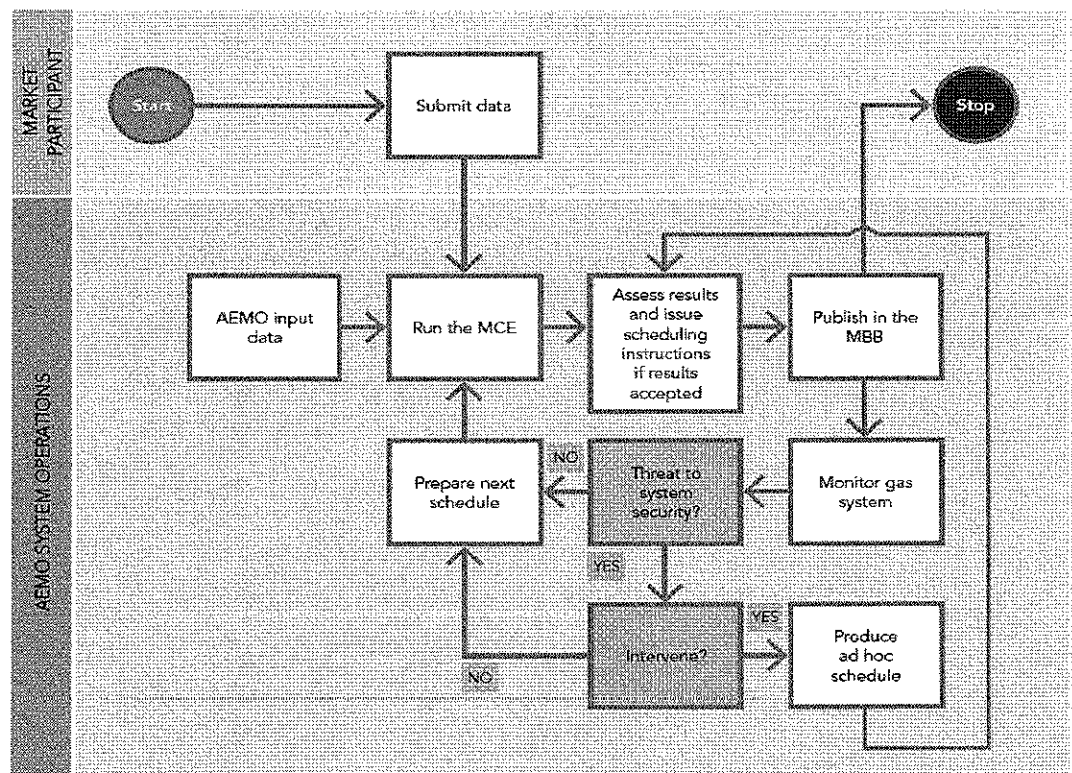
F.   Events of 15 March 2010

16. Since October 2009, Jemena (a *Distributor*, responsible for operation of the Eastern Gas Pipeline (**EGP**)) has been installing and commissioning new compressors near Longford, which required several half-day periods of zero gas flow into the Eastern Gas Pipeline. As this would impact Victoria's main supplier of gas into Victoria, Esso Australia Resources Pty Ltd (**Esso**), AEMO had met with both Jemena and Esso (a *Producer*) to consider the impacts of these works on the security of the DTS and the market and how any risks to security could be alleviated. It was decided that applying a supply-demand point constraint (**SDPC**) at the Longford injection point to the DTS to enable Esso to have steady production flows across a gas day could achieve this with no impact on system security or the market.

17. This strategy was implemented on 15 March 2010, as it had on a number of occasions previously, but for a shorter period,[3] which resulted in an unexpected conflict with certain accredited contractual supply constraint settings in the market clearing system. The effect of this was that gas bid at a higher price than the market price was scheduled to flow at Longford.

18. AEMO investigated the events of 15 March 2010 in accordance with rule 218(1)(b) and prepared a detailed report titled 'Unintended Scheduling Result Gas Day 15 March 2010'. A copy of the report is reproduced in **Schedule 1** of this submission.

19. AEMO determined that an *unintended scheduling result* occurred on 15 March 2010 with financial impacts in the 6am, 10am and 2pm schedules.

G.   Participant Compensation Fund

20. AEMO is not liable for an *unintended scheduling result*. Compensation for affected *Market Participants* is paid out of the PCF.[4]

21. AEMO is required to maintain the PCE under rule 225. The purpose of the PCF is to compensate *Market Participants* following an *unintended scheduling result*.

22. The current balance in the PCF is $2,850,477.42.

23. AEMO is required to replenish the PCF with fees collected from *Market Participants* in accordance with rules 225(3)-(6). For each *financial year*,[5] the funding requirement for the PCF is the lesser of:

   - $500,000; and
   - $1,000,000 minus the amount AEMO reasonably expects to be the balance at the end of the relevant *financial year*.[6]

24. In making a determination as to compensation, a DRP must take into account the matters detailed in rule 226(1), which are:

   - which *Market Participant* is to receive compensation;
   - the amount of the compensation for each *Market Participant*; and
   - the manner and timing of payments from the PCF.

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[3] 11 hours instead of 13 hours.
[4] Rule 227(2).
[5] *Financial year* is defined as a period commencing on 1 July and terminating on the following 30 June.
[6] Rule 225(2).

H. Liability to pay Compensation

25. Rule 226 requires that the occurrence of an *unintended scheduling result* be confirmed either by agreement or determination in accordance with the dispute resolution processes in the NGR.

26. The parties submit that the *unintended scheduling result* has occurred as a result of the application of rule 217(1)(b), namely, that a quantity of gas under an *injection bid* above the *market price* was scheduled for injection and the relevant *Market Participant* did not receive the *bid* price in respect of that *injection* in accordance with the scheduling instruction.

27. The parties also submit that none of the exceptions detailed in rule 217(2) apply.

28. The exceptions in rule 217(2)(a) provide for expected impacts on schedules and market outcomes arising from physical or contractual constraints on gas flows and other matters. Such constraints are routinely applied in the scheduling and operations processes and no compensation is applicable.

29. Of interest, however, are rules 217(2)(a)(vii) and 217(2)(a)(ix).

30. Under normal circumstances, gas priced lower than the market price might not be scheduled because the physical production limits or contracts do not enable this gas to flow. *Market Participants* whose gas is affected in this way are rightly not eligible for compensation.

31. Accredited constraints and SPDCs both limit rates of gas flows to reflect contract or physical production constraints, such as hourly or daily rates or ramping rates. They might also cover things, such as periods of notice, specific times or windows when ramping supply up or down is to occur. On 15 March 2010, the accredited constraints were unchanged from their normal standing settings.

32. SDPCs are normally used reflect a production facility flow limit due to a planned or unplanned facility outage or part outage. The total flow at an injection point has hourly flow limits applied and it is normal for bids priced lower than the market price not to be scheduled. *Market Participants* whose gas is affected in this way are also not eligible for any compensation.

33. On 15 March 2010 there was no facility production limit and, under normal circumstances, no SPDC would be applied, however, a profiling SPDC had been applied on a number of occasions to enable works on the EGP that involved profiling gas injections at Longford on the day. Injections at Longford are normally scheduled on a uniform injection rate basis. It should be noted that this special SPDC did not affect total daily quantities scheduled and, therefore, did not affect the market price or market settlements outcomes. The strategy had worked successfully on several occasions prior to 15 March 2010.

34. On 15 March 2010, however, due to a change in the duration of the SPDC from 13 hours to 11 hours, there was an unforeseen and unintended consequence because the SPDC period did not align with the ramping time/window applicable to Longford injections. This resulted in gas priced higher than the market price being scheduled, but not being compensated in accordance with rule 217(1)(b). Rule 217(1)(c) did not apply.

35. The application of the altered SPDC on 15 March 2010 conflicted with *Market Participants'* standing accredited supply constraints and so did not schedule gas as intended and, thus, unintentionally impacted daily quantities and market

settlements outcomes. On this basis, 217(2)(a), which applies to normal operational matters, does not apply.

36. Rule 217(2)(b) does not apply as no *Market Participant* has been paid compensation for this event.

37. Rule 217(3) is not relevant because no error was made in determining the market price on the day. The pricing schedule process worked correctly without error.

38. The parties submit that rule 217(4) is also not applicable, as the claims from each affected *Market Participant* individually and collectively exceed the minimum thresholds set out in that rule.

39. The affected *Market Participants* are AGL and Origin.

I.   Calculation of AGL's Loss

40. AEMO and AGL agree that compensation as a result of the *unintended scheduling result* ought to be calculated in accordance with the Ancillary Payments Procedures. A copy of the relevant issue of the Procedures is contained in **Schedule 2**.

41. The magnitude of the loss incurred by AGL as a result of this *unintended scheduling result* is $23,741.61 (GST inclusive).

42. AGL seeks compensation to cover its full loss of $23, 741.61. AEMO agrees with this calculation of AGL's loss arising from the *unintended scheduling result.*

43. The detailed calculations of AGL's loss are contained in the spreadsheet attached in **Schedule 3**.

J.   Calculation of Origin's loss

44. AEMO and Origin agree that compensation as a result of the *unintended scheduling result* ought to be calculated in accordance with the Ancillary Payments Procedures. A copy of the relevant issue of the Procedures is contained in **Schedule 2**.

45. The magnitude of the loss incurred by Origin as a result of this *unintended scheduling result* is $50,858.04 (GST inclusive).

46. Origin seeks compensation to cover its full loss of $50,858.04. AEMO agrees with this calculation of Origin's loss arising from the *unintended scheduling result.*

47. The detailed calculations of Origin's loss are contained in the spreadsheets attached in **Schedule 4**.

K.   Payment of Compensation

48. Rule 227(1) also requires that the aggregate amount of compensation paid each year from the PCF must not exceed the balance that would have been available at the end of that year had no compensation payments been made that year and therefore the DRP must, when making a determination, take into account the following requirements:

- the aggregate amount of compensation determined under rule 226 must not exceed the balance of the PCF at the time the determination is made,

less any amount not yet paid from the PCF in respect of any previous determinations; and

- the aggregate amount of compensation payable from the PCF at any time is limited to its balance.

49. Since the commencement of the market there have been no payments made from the PCF.

50. There are no other claims made or anticipated to be made against the PCF.

51. The *Adviser* issued a notice on 19 May 2010 to the DMS contacts regarding the receipt of a claim against the PCF in respect of this *unintended scheduling result.* No further claims were notified.

52. If the compensation was paid for the full amount of AGL's and Origin's losses, the balance in the *Participant compensation fund* would be $2,775,877.77 (GST inclusive).

53. Accordingly, full payment of AGL's and Origin's losses is appropriate taking into account the current balance of the *Participant compensation fund* and the low likelihood of any further actual liabilities being incurred this financial year.

L. Interest

54. AGL and Origin do not seek payment of interest on their losses as part of this application. However, for the purpose of any future applications for compensation in respect of *unintended scheduling results* AGL and Origin wish to reserve their respective positions as to whether interest can be included in an amount of compensation ordered to be paid by a DRP from the PCF.

M. Costs

55. For the purposes of this compensation claim the parties submit that the costs of this process (other than the legal costs of the parties) should be borne equally by them and that each of them should bear its own legal costs. It is submitted that the DRP should not exercise any discretion it may have under rule 135JA to allocate costs on a different basis as none of AGL, Origin or AEMO, has unreasonably prolonged or escalated a dispute or otherwise increased the costs of the DRP proceedings.

56. For the purposes of any applications for compensation in respect of future *unintended scheduling results,* AGL reserves its position as to whether an application for compensation from the PCF is a dispute under the NGR or subject to rule 135JA.

DATED: 8 June 2010

AGL Sales Pty Ltd
Origin Energy Ltd
Australian Energy Market Operator Ltd

SCHEDULE 1
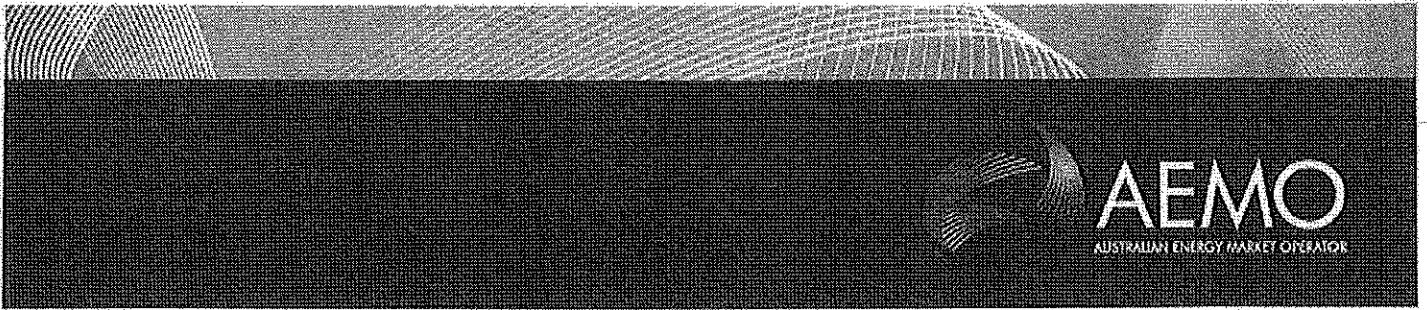
UNINTENDED SCHEDULING RESULT

Gas day 15 March 2010

PREPARED BY:	Market Development and Market Operations
DOCUMENT REF:	02/0827/1/#301972 v1
DATE:	12 April 2010

Authorised by: _____

T Grimwade

Executive General Manager, Market Development

Unintended Scheduling Result: 15 March 2010

Background

In accordance with rule 218(1)(b) of the National Gas Rules, AEMO on its own initiative commenced an investigation into whether an *unintended scheduling result* occurred in the 6am schedule and any subsequent reschedules on 15 March 2010. On 30 March 2010, AEMO published a notice to this effect.

This Report includes AEMO's decision and the reasons for its decision in accordance with rule 218(3) of the National Gas Rules.

Decision

AEMO has determined that an *unintended scheduling result* occurred in the 6am, 10am and 2pm schedules on 15 March 2010. The 6am schedule was primarily impacted with smaller impacts in the 10am and 2pm schedules.

'Minimum injection profile' supply-demand point constraints "SDPCs" had been used in accordance with the Gas Scheduling Procedures on several occasions over summer on request from Exxon-Mobil. The purpose was to ensure that the schedules produced by the Market Clearing Engine (MCE) correctly took into account the gas injection profiling on the day at the Longford injection point that was caused by Jemena's compressor works conducted on the Eastern Gas Pipeline (EGP).

On 15 March 2010 the market system generated schedules subject to a similar SDPC but of shorter duration at Exxon-Mobil's and Jemena's request. This SDPC and Market Participants' accredited constraints were not compatible and, in effect, caused the minimum injection rate constraint to apply for the whole of the gas day rather than the first part of the day as intended. The outcome was that a quantity of gas priced higher than the market price was scheduled from the Longford injection point in both the pricing and operating schedules. The higher priced gas was treated as a *minimum schedule injection quantity* (MSIQ) and, in accordance with the settlements algorithm, this gas was settled at the market price and not the bid price. The scheduling outcome was due to the change in the SDPC and not because of the Market Participants' accredited constraints. As a consequence, AEMO estimates that the Market Participants flowing this gas were short-paid in the 6am schedule some $80,000 collectively relative to the relevant bid prices, with further changes in payments in the subsequent two reschedules.

Explanation of scheduling events on 15 March 2010

Jemena has been installing and commissioning new compressors since October 2009 and has required several half-day periods of zero gas flow into the EGP to enable the particular work. Before this, Exxon-Mobil and Jemena had met with AEMO to discuss the impacts of the augmentation works on the Victorian DTS and to mitigate the associated risks to gas supply. This could be achieved by applying a SDPC at the Longford injection point to enable Exxon-Mobil to have steady production flows across the gas day. AEMO's market systems would then schedule Longford injections into the DTS at rates which are higher during the first part of the gas day and lower over the evening and night, while at the same time flows into the EGP/TGP would complement those into the DTS to support a steady Longford plant production rate over the whole gas day.

Accordingly, on several selected days prior to 15 March 2010 as agreed with Exxon Mobil, AEMO applied a minimum hour flow SDPC at the Longford injection point to reflect the higher injection rates as requested. This SDPC was applied for 13 hours on each occasion, which aligns with Market Participants' contractual nomination window to enable reduction of the Longford injection

rate later in the gas day. This process had been thoroughly tested prior to implementation and had worked successfully on each of several occasions prior to 15 March 2010.

However, for the gas day 15 March 2010, on request from Exxon-Mobil and as agreed by Jemena, the SDPC was applied for the first 11 hours only. The 6am schedule was generated as usual but it was not apparent at that time that there was a scheduling issue.

Later that morning a Market Participant communicated concerns to AEMO regarding the 6am schedule, and preliminary investigations found that two Market Participants had some gas injections that had been scheduled 'out of merit order' at the Longford meter (30000001PC) ie. some gas bid at prices higher than the market price had been scheduled in both the market schedule and the operating schedule.

AEMO's investigation concluded that the eleven hour SDPC setting conflicted with some Market Participants' Longford contractual settings set in the accreditation table in the market system. Ramping down could not occur after eleven hours as intended during the MCE process and additional higher priced gas was forced to be scheduled at Longford. AEMO has had Dr W Pepper of ICF Consulting confirm its understanding of how the market clearing engine produced these schedules.

The 6am schedule information is shown in Table 1. The 6am market price was set at $1.107 which aligns with total scheduled injections at the Longford meter of 178,234 GJ. However a further 32,304 GJ of gas was scheduled from the next higher priced bids at the Longford meter ranging from $3.4869 to $3.7769 (shaded in pink). This gas was scheduled due to the incompatible constraints and was treated as MSIQ flows and so was paid at market price in accordance with the settlements procedures i.e. where gas flows scheduled due to a Market Participant's accredited constraints do not qualify for ancillary payments. However, it is clear that the constraint causing the issue was the SPDC and not the Market Participants' accredited constraints.

Table 1. 15 March 2010 6am Schedule Data

Price	Bid Step	Schedule	Short-paid
$0.0000	111,000	111,000	$0
$0.0000	55,000	55,000	$0
$0.0001	16	16	$0
$0.0107	0	0	$0
$0.3889	12,212	12,212	$0
$1.1069	6	6	$0
$2.5901	0	0	$0
$3.4869	6,839	6,839	$16,277
$3.5000	10,000	10,000	$23,931
$3.7769	16,632	15,465	$41,292
$4.1100	10,000	0	$0
$4.9900	10,000	0	$0
$5.1469	35,947	0	$0
$123.4567	50,000	0	$0
$765.4321	50,000	0	$0
Total	**367,652**	**210,538**	**$81,499**

Table 1 show the relevant bids and scheduled quantities for the 6am schedule for the Longford injection point on 15 March 2010. On the day, two Market Participants were affected. In the 6am schedule these Market Participants were short paid an estimated total of $81,499 as indicated in

Table 1. The final short-paid amounts will differ, due to changes in the following schedules and deviations from schedule.

After contact by an impacted Market Participant that morning AEMO Gas System Operations Support investigated the issue and took a decision to maintain the SDPC as this would minimise further impact on Market Participants. Therefore the SDPC was not revised for reschedules for gas day 15 March 2010.

The constraint violation was due to the conflict between the SDPC setting and the Market Participants accredited constraints impacted settlements for the 6am, 10am and 2pm schedules but did not cause further impact in the 6pm and 10pm schedules.

SCHEDULE 2

WHOLESALE MARKET ANCILLARY PAYMENT PROCEDURES (VICTORIA)

DOCUMENT NO:

VERSION
NO:NGR 1.0

szpm A0114621322v1 306207337

VERSION CONTROL

NGR 1.0		C Diep	Rebranded and updated for NGR
1.2	May 2008		Updated to incorporate AP Flip Flop and clawback methodologies
1.1	January 2007		Remove words "minus one multiplied by" written into section 8.1
			Amend errors detected in version 1.0
1.0	11 November 2005		First Issue

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CHAPTER 1 – PRELIMINARY

1.1 Introduction

These are the Procedures made under Rule 239 of the National Gas Rules (**Rules**).

The purpose of these Procedures is to set out the methodology for determining ancillary payments.

1.2 – Definitions

Terms defined in the Law and Part 19 of the Rules have the same meaning in these Procedures unless the context otherwise requires. In addition:

AGINO or **Actual Gas Injection Negative Offset Quantity** has the meaning given in clause 2.4.

AGWNO or **Actual Gas Withdrawal Negative Offset Quantity** has the meaning given in clause 2.4

BoD means the beginning of the gas day.

controllable withdrawal means a quantity of gas that may be scheduled for withdrawal at a system withdrawal point and modified on a gas day in accordance with a withdrawal bid and the applicable accreditation by AEMO under Rule 210.

controllable injection means a quantity of gas that may be scheduled for injection at a system injection point and modified on a gas day in accordance with an injection bid and the applicable accreditation by AEMO under Rule 210.

Market Participant constraint means in respect of a Market Participant, the quantity of gas nominated by that Market Participant that must be injected or withdrawn during a pricing and operating schedule, irrespective of the market price for that pricing schedule in order to meet that Market Participant's contractual constraints.

MSIQ or **Minimum Scheduled Injection Quantity** has the meaning given in clause 2.3.

MSWQ or **Minimum Scheduled Withdrawal Quantity** has the meaning given in clause 2.3.

Reference Hub means a notional common point of reference within the declared transmission system established by AEMO for the purpose of valuing authorised MDQ and AMDQ credit certificates.

Reference Hub AMDQ credit nomination means all or part of an AMDQ credit certificate nominated to the Reference Hub by a Market Participant.

Reference Hub AMDQ credits means AMDQ credits held by a Market Participant at the Reference Hub for the purpose of hedging against uplift payments.

Reference Hub authorised MDQ means authorised MDQ held by a Market Participant at the Reference Hub for the purpose of hedging against uplift payments.

CHAPTER 2 – ANCILLARY PAYMENTS – GENERAL

2.1 Constrained on injections and withdrawals

In accordance with Rule 239(3) and subject to Rules 239(4),(5) and (6), a Market Participant who is given a scheduling instruction to inject or withdraw more gas under the operating schedule than the quantity of gas that the Market Participant was scheduled to inject or withdraw under the relevant pricing schedule, is entitled to receive an ancillary payment. For the purposes of these Procedures, any such increased injection is deemed to be a constrained on injection quantity and any such increased withdrawal is deemed to be a constrained on withdrawal quantity.

Ancillary payments are adjusted at each operating schedule during the gas day.

Until such time as:

(a)   the constrained on injection quantity is injected into the relevant system injection point; or

(b)   the constrained on withdrawal quantity is withdrawn from the relevant system withdrawal point,

by the Market Participant, the amount of ancillary payments payable to that Market Participant in respect of that constrained on injection quantity or withdrawal quantity (as applicable) increases or decreases at each subsequent updated operating schedule in that gas day to the extent that the amount of the constrained on injection quantity or constrained on withdrawal quantity increases or decreases in each subsequent updated operating schedule in that gas day.

2.2 Market Participant constraint

Any part of a Market Participant's constrained on injection quantity or withdrawal quantity which arises as a result of that Market Participant's Market Participant constraint will not generate ancillary payments and

(a)   that part of the constrained on injection quantity is deemed to be the Minimum Scheduled Injection Quantity (*MSIQ*); and

(b)   that part of the constrained on withdrawal quantity is deemed to be the Minimum Scheduled Withdrawal Quantity (**MSWQ**),

for the purposes of the calculations in clauses 6.1 and 6.2 of these Procedures respectively.

2.3   Actual injections or withdrawals of gas

Where a Market Participant:

(a)   injects less than the constrained on injection quantity; or

(b)   withdraws less than the constrained on withdrawal quantity,

ancillary payments will not be generated in respect of that shortfall in constrained on injection or withdrawal quantity (as applicable) and for the purposes of the calculations in clauses 5.1 and 5.2 of these Procedures, such shortfall in the constrained on injection quantity is deemed to be the Actual Gas Injection Negative Offset Quantity (**AGINO**) and such shortfall in the constrained on withdrawal quantity is deemed to be the Actual Gas Withdrawal Negative Offset Quantity (**AGWNO**).

Where a Market Participant:

(a)   injects more than the constrained on injection quantity; or

(b)   withdraws more than the constrained on withdrawal quantity,

ancillary payments will not be generated in respect of that excess of constrained on injection or withdrawal quantity (as applicable).

2.4   Uplift hedges

If a Market Participant nominates to use part or all of a gas injection as an uplift hedge, then that portion of the gas injection used as an uplift hedge will not generate ancillary payments.

2.5   Accreditation

No ancillary payments are generated for constrained on injection quantities or withdrawal quantities, unless those quantities are accredited by AEMO under Rule 210.

CHAPTER 3 – DETERMINATION OF ADJUSTED BID STEPS AND SCHEDULED INJECTION USED FOR UPLIFT HEDGE

3.1 Determination of scheduled injection used for uplift hedge

The sum of a Market Participant's injection hedge nomination and agency injection hedge nominations for a gas day as determined under the Wholesale Market (Uplift Allocation) Procedures will not generate ancillary payments. For the purpose of these Procedures, this quantity is known as uplift hedge.

3.2 Determination of adjusted bid steps

For each injection or withdrawal bid in respect of any pricing and operating schedule, break points are determined automatically by AEMO between bid steps from zero up to the maximum quantity offered by that Market Participant as shown by way of example in Table 1.

The break point at which any uplift hedge (assumed to be 37 GJ in the example in Table 1) applies is also determined by AEMO.

As shown by way of example in columns 1 and 2 in Table 2, all break points across all pricing and operating schedules are ranked by their cumulative quantities so that there are up to:

(a)   55 withdrawal break points between 0 and the maximum quantity bid over all schedules; and

(b)   56 injection break points between 0 and the maximum quantity bid over all schedules in order to accommodate all 10 possible bid steps, the minimum daily quantity offer and the uplift hedge nomination over the five schedules in the gas day.

For each injection or withdrawal bid in respect of each pricing and operating schedule, the existing bid steps are divided by AEMO into more steps by applying the new break points. This is carried out by associating each pricing break point for each schedule with each cumulative quantity break point.

The resulting divided injection or withdrawal bids are used by AEMO in the calculations set out in Chapters 4 to 7 of these Procedures.

Table 1

Bid step	BoD Schedule		1st reschedule		2nd reschedule		Uplift Quantity (GJ)
	Cumulative Quantity (GJ)	Bid Price ($/GJ)	Cumulative Quantity (GJ)	Bid Price ($/GJ)	Cumulative Quantity (GJ)	Bid Price ($/GJ)	
1	15	2.0	16	2.1	17	2.2	
2	30	2.5	32	2.6	34	2.7	
3	45	3.0	48	3.1	51	3.2	37
4	60	3.5	64	3.6	68	3.7	
5	75	4.0	75	4.1	75	4.2	

Table 2

Adjusted Bid step	Cumulative Quantity (GJ)	Bid Price			Uplift Hedge
		BoD Schedule ($/GJ)	1st reschedule ($/GJ)	2nd reschedule ($/GJ)	
1	15	2.0	2.1	2.2	Yes
2	16	2.5	2.1	2.2	Yes
3	17	2.5	2.6	2.2	Yes
4	30	2.5	2.6	2.7	Yes
5	32	3.0	2.6	2.7	Yes
6	34	3.0	3.1	2.7	Yes
7	37	3.0	3.1	3.2	Yes
8	45	3.0	3.1	3.2	No

Adjusted Bid step		Bid Price			
	Cumulative Quantity (GJ)	BoD Schedule ($/GJ)	1st reschedule ($/GJ)	2nd reschedule ($/GJ)	Uplift Hedge
9	48	3.5	3.1	3.2	No
10	51	3.5	3.6	3.2	No
11	60	3.5	3.6	3.7	No
12	64	4.0	3.6	3.7	No
13	68	4.0	4.1	3.7	No
14	75	4.0	4.1	4.2	No

3.3 Association of bid prices with adjusted bid steps

The bid prices associated with the adjusted bid steps of each pricing and operating schedule are set by AEMO equal to the bid price for that bid step in that schedule.

If AEMO has limited the market price to the administered price cap for a schedule in accordance with Rule 239(5) then the bid prices associated with the adjusted bid steps for that schedule are capped at the administered price cap.

CHAPTER 4 – DETERMINATION AND ALLOCATION OF QUANTITIES TO ADJUSTED BID STEPS

4.1 Pricing schedule

4.1.1 Determination of effective pricing schedule quantities for ancillary payments

For each Market Participant, the effective pricing schedule quantity used by AEMO in calculating ancillary payments for that Market Participant's pricing schedule controllable quantity at each system injection and withdrawal point is:

(a) for the initial pricing schedule of the gas day, equal to the pricing schedule quantity produced at the start of the gas day; and

(b)   for each subsequent updated pricing schedule of the gas day, equal to:

   (i)   the pricing schedule quantity for the scheduling horizon of that subsequent updated pricing schedule

   plus

   (ii)   the sum of each pricing schedule quantity for each relevant scheduling interval for each of the previous pricing schedules.

4.1.2 Allocation of effective pricing schedule quantities to adjusted bid steps

The pricing schedule controllable quantities determined under clause 4.1.1 for a Market Participant for each pricing schedule are allocated to the adjusted bid steps of the bid that applied for that pricing schedule in order of increasing price for injections and decreasing price for withdrawals.

4.2   Operating schedule

4.2.1 Determination of operating schedule quantities for ancillary payments

For each Market Participant, the operating schedule quantity used by AEMO in calculating ancillary payments for that Market Participant's operating schedule controllable injection or operating schedule controllable withdrawal is:

(a)   for the initial operating schedule of the gas day, equal to the operating schedule quantity produced at the start of the gas day; and

(b)   for each subsequent operating schedule of the gas day, equal to:

   (i)   the operating schedule quantity of that subsequent operating schedule for the scheduling horizon

   plus

   (ii)   the sum of each operating schedule quantity for each scheduling interval related to each of the previous operating schedules.

If an ad hoc operating schedule is produced to replace an already approved operating schedule, then the schedule quantity for the scheduling interval in that ad hoc operating schedule will be used to calculate the operating schedule quantities.

4.2.2 Allocation of operating schedule quantities to adjusted bid steps

The operating schedule controllable quantities determined under clause 4.2.1 for a Market Participant for each operating schedule are allocated to the adjusted bid steps of the bid that applied for that operating schedule in order of increasing price for injections and decreasing price for withdrawals.

CHAPTER 5 – ACTUAL QUANTITIES

The following clause sets out the methodology used by AEMO to calculate for each Market Participant, the quantity of gas within each adjusted bid step of an operating schedule that will not generate ancillary payments due to that Market Participant's failure to comply with the relevant scheduling instruction.

5.1 Calculation of Actual Gas Injected Negative Offset (AGINO)

5.1.1 Determination of effective actual injection quantity

A Market Participant's effective actual injection quantity at a controllable injection point in a scheduling interval is a quantity of gas equal to the lesser of:

(a)   the last approved operating schedule injection approved by AEMO for; and

(b)   the quantity of gas actually injected by,

that Market Participant at that controllable injection point in that scheduling interval.

A Market Participant's effective actual injection quantity at a controllable injection point for a gas day is the sum of the effective actual injection quantity of all the scheduling intervals for that gas day.

5.1.2 Allocation of effective actual injection quantity to adjusted bid steps

A Market Participant's effective actual injection quantity for a controllable injection point for an operating schedule will be allocated by AEMO to the adjusted bid steps of the bid that applied to that operating schedule in order of increasing price.

5.1.3 Calculation of AGINO for the last operating schedule of the gas day

A Market Participant's AGINO for a controllable injection point for each adjusted bid step in the last operating schedule of the gas day is a quantity of gas equal to the greater of:

(a)   zero; and

(b) the operating schedule injections for that adjusted bid step for the last operating schedule of the gas day allocated in accordance with clause 4.2.2 less the effective actual injections allocated to that adjusted bid step in accordance with clause 5.1.2.

5.1.4 Calculation of AGINO for operating schedules prior to the last operating schedule of the gas day

A Market Participant's AGINO for a controllable injection point for each adjusted price step in each operating schedule prior to the last operating schedule of the gas day is a quantity of gas equal to the greater of:

(a) zero; and

(b) the AGINO for that adjusted bid step as determined under clause 5.1.3

less

(i) the operating schedule injections for that adjusted bid step for the last operating schedule of the gas day allocated in accordance with clause 4.2.2; and

(ii) the minimum of operating schedule injections for that adjusted bid step for the specified operating schedule and all the subsequent operating schedules for the remainder of the gas day allocated in accordance with clause 4.2.2.

5.2 Calculation of Actual Gas Withdrawn Negative Offset (AGWNO)

5.2.1 Determination of effective actual withdrawal quantity

A Market Participant's effective actual withdrawal quantity from a controllable withdrawal point in a scheduling interval is a quantity of gas equal to the lesser of:

(a) the last approved operating schedule withdrawal approved by AEMO for; and

(b) the quantity of gas actually withdrawn by

that Market Participant at that controllable withdrawal point in that scheduling interval.

A Market Participant's effective actual withdrawal quantity at a controllable withdrawal point for a gas day is the sum of that Market Participant's effective actual withdrawal quantity of all the scheduling intervals.

5.2.2 Allocation of the effective actual withdrawal quantity to adjusted bid steps

The quantity determined under clause 5.2.1 for each Market Participant for each controllable withdrawal point for each operating schedule is then allocated by AEMO to the adjusted bid steps of the bid that applied to that operating schedule in order of decreasing price.

5.2.3 Calculation of AGWNO for the last operating schedule of the gas day

A Market Participant's AGWNO for each controllable withdrawal point for each adjusted bid step for the last operating schedule of the gas day is the greater of:

(a)   zero; and

(b)   the operating schedule withdrawals by that Market Participant for that adjusted bid step for the last operating schedule of the gas day allocated in accordance with clause 4.2.2

less

the effective actual withdrawals by that Market Participant allocated to that adjusted bid step in accordance with clause 5.2.2.

5.2.4 Calculation of AGWNO for schedules prior to the last schedule of the gas day

A Market Participant's AGWNO for each controllable withdrawal point for each adjusted bid step for each operating schedule prior to the last operating schedule of the gas day is the greater of:

(a)   zero; and

(b)   that Market Participant's AGWNO for that adjusted bid step determined under clause 5.2.3

less

(i)   the operating schedule withdrawals by that Market Participant for that adjusted bid step for the last operating schedule of the gas day allocated in accordance with clause 4.2.2; and

(ii)   the minimum of operating schedule withdrawals by that Market Participant for the adjusted bid step for the specified operating schedule and all the subsequent operating schedules for the remainder of the gas day allocated in accordance with clause 4.2.2.

CHAPTER 6 – MARKET PARTICIPANT CONSTRAINTS

6.1 Calculation of Minimum Scheduled Injection Quantity (MSIQ)

6.1.1 Calculation of MSIQ for the last operating schedule of the gas day

Where applicable, a Market Participant's MSIQ for each controllable injection point for each adjusted bid step for the last approved operating schedule of the gas day is a quantity of gas equal to that Market Participant's effective pricing schedule quantity for that controllable injection point for the last pricing schedule of the gas day allocated in accordance with clause 4.1.2.

6.1.2 Calculation of MSIQ for operating schedules prior to the last operating schedule of the gas day

Where applicable, a Market Participant's MSIQ for each controllable injection point for each adjusted bid step for each operating schedule prior to the last operating schedule of the gas day is determined by AEMO as follows:

(a)   if the adjusted bid step price for an operating schedule exceeds the market price applicable for that operating schedule, that Market Participant's MSIQ for that adjusted bid step equals that Market Participant's effective pricing schedule injection quantity for that adjusted bid step allocated in accordance with clause 4.1.2; or

(b)   if the adjusted bid step price for an operating schedule is less than or equal to the market price applicable for that operating schedule, that Market Participant's MSIQ for that adjusted bid step equals the lesser of:

(i)   that Market Participant's effective pricing schedule injection quantity for that adjusted bid step for that pricing schedule as determined under clause 4.1.2; and

(ii)   that Market Participant's MSIQ for the adjusted bid step for the immediately following operating schedule.

6.2 Calculation of Minimum Scheduled Withdrawal Quantity (MSWQ)

6.2.1 Calculation of MSWQ for the last operating schedule of the gas day

Where applicable, a Market Participant's MSWQ for each controllable withdrawal point for each adjusted bid step for the last approved operating schedule of the gas day equals that Market Participant's effective pricing schedule quantity for the last pricing schedule of the gas day allocated in accordance with clause 4.1.2.

6.2.2 Calculation of MSWQ for operating schedules prior to the last pricing schedule of the gas day

Where applicable, a Market Participant's MSQW for each controllable withdrawal point for each adjusted bid step for each operating schedule of a gas day prior to the last operating schedule of that gas day is determined as follows:

(a)   if the adjusted bid step for an operating schedule is less than the market price applicable for that operating schedule, that Market Participant's MSWQ for that adjusted bid step equals that Market Participant's effective pricing schedule withdrawal quantity for that adjusted bid step determined under clause 4.1.2; or

(b)   if the adjusted bid step for an operating schedule is greater than or equal to the market price applicable for that operating schedule, then that Market Participant's MSWQ for that adjusted bid step equals the lesser of:

   (i)   that Market Participant's effective pricing schedule withdrawal quantity for that adjusted bid step for that pricing schedule determined under clause 4.1.2; and

   (ii)   that Market Participant's MSWQ for that adjusted bid step for the following operating schedule.

CHAPTER 7 Calculation Of ancillary payments

7.1   Determining the constrained on injection quantity for an adjusted bid step and operating schedule

A Market Participant's constrained on injection quantity for each controllable injection point for each adjusted bid step for each operating schedule is determined by AEMO as the greater of:

(a)   zero; and

(b)   that Market Participant's operating schedule injection quantity at that controllable injection point for that adjusted bid step and operating schedule allocated in accordance with clause 4.2.2

   less

   that Market Participant's AGINO for that adjusted bid step and operating schedule at that controllable injection point as determined under clauses 5.1.3 and 5.1.4

   less

that Market Participant's MSIQ for that adjusted bid step and operating schedule at that controllable injection point as determined under clauses 6.1.1 and 6.1.2.

7.2 Determining the constrained on withdrawal quantity for a bid step and operating schedule

A Market Participant's constrained on withdrawal quantity for each controllable withdrawal point for each adjusted bid step for each operating schedule is determined by AEMO as the greater of:

(a)   zero; and

(b)   that Market Participant's operating schedule withdrawal quantity for that adjusted bid step and operating schedule at that controllable withdrawal point allocated in accordance with clause 4.2.2,

       less

       that Market Participant's AGWNO for that adjusted bid step and that operating schedule at that controllable withdrawal point determined under clauses 5.2.3 and 5.2.4,

       less

       that Market Participant's MSWQ for that adjusted bid step and that operating schedule at that controllable withdrawal point as determined under clauses 6.2.1 and 6.2.2.

7.3 Calculation of matched changes in constrained on injection and withdrawal quantities

7.3.1 Calculation of matched changes in constrained on injection quantity for an adjusted bid step and operating schedule

A Market Participant's matched change in constrained on injection quantities for each controllable injection point and each adjusted bid step is the quantity of constrained on injection quantity which was scheduled in an earlier operating schedule but was scheduled off in a subsequent operating schedule.

The matched change in constrained on injection quantities for each controllable injection point for each adjusted bid step for each operating schedule is calculated by AEMO for each combination of two different operating schedules of the gas day starting with the second operating schedule (s=2) and then iterating forward to the last operating schedule (s=5), as shown in the example in the table below.

Operating schedule (s)	Combinations of operating schedules (s,s')
S=2	(2,1)
S=3	(3,2), (3,1)
S=4	(4,3), (4,2), (4,1)
S=5	(5,4), (5,3), (5,2), (5,1)

For each operating schedule s in a gas day and for each earlier operating schedule s' = s-1, s-2, ...,1 (in that order) in that gas day, a Market Participant's matched change in constrained on injection quantity for schedules s and s' is calculated by AEMO as follows:

- if s' = s-1 (i.e. combinations (2,1), (3,2), (4,3), (5,4)), the matched change in constrained on injection quantities equals the lesser of:

  - the greater of zero and the negative of the change in that Market Participant's constrained on injection quantity at operating schedule s; and

  - the greater of zero and the change in that Market Participant's constrained on injection quantity at operating schedule s'.

- otherwise, the matched change equals the lesser of:

  - the greater of zero and the negative of the change in that Market Participant's constrained on injection quantity at operating schedule s less the sum over all operating schedules s" from operating schedule s'+1 to operating schedule s-1 of that Market Participant's matched change in constrained on injection quantity for combinations of operating schedules s and s"; and

  - the greater of zero and the change in that Market Participant's constrained on injection quantity at operating schedule s,' less the sum over all operating schedules s" from operating schedule s'+1 to operating schedule s-1 of the matched change in constrained on injection quantity for combinations of operating schedules s' and s".

7.3.2 Calculation of the matched change in constrained on withdrawal quantity for a bid step and schedule

A Market Participant's matched change in constrained on withdrawal quantity for each controllable withdrawal point and each adjusted bid step is calculated by AEMO for each combination of two different operating schedules of the gas day for each operating schedule starting with the second operating schedule (s=2) and then iterating forward to the last operating schedule (s=5).

Operating schedule (s)	Combinations of operating schedules (s,s')
S=2	(2,1)
S=3	(3,2), (3,1)
S=4	(4,3), (4,2), (4,1)
S=5	(5,4), (5,3), (5,2), (5,1)

For each operating schedule s and for each earlier operating schedule s' = s-1, s-2, ...,1 (in that order) in that gas day, a Market Participant's matched change in constrained on withdrawal quantity for schedules s and s' is calculated as follows :

- o if s' = s-1 (i.e. combinations (2,1), (3,2), (4,3), (5,4)), the matched change in constrained on withdrawal quantity equals the lesser of :

  - the greater of zero and the negative of the the change in that Market Participant's constrained on withdrawal quantity at operating schedule s; and

  - the greater of zero and the change in that Market Participant's constrained on withdrawal quantity at operating schedule s'.

- o otherwise, the matched change in constrained on withdrawal quantities equals the lesser of:

  - the greater of zero and the negative of the change in that Market Participant's constrained on withdrawal quantity at operating schedule s less the sum over all operating schedules s" from s"= s'+1 to s"=s-1 of the matched change in that Market Participant's constrained on withdrawal quantity for combinations of schedules s and s"; and

- the greater of zero and the change in constrained on withdrawal quantity at operating schedule s', less the sum, over all operating schedules s" from operating schedule s"= s'+1 to operating s"=s-1, of the matched change in constrained on withdrawal quantity for combinations of schedules s' and s".

7.4 Calculation of ancillary payments for injection quantities

7.4.1 Calculation of initial ancillary payments for the initial operating schedule of the gas day

The initial injection ancillary payment (if any) payable to a Market Participant for each controllable injection point for each adjusted bid step for the first operating schedule in the gas day is calculated by AEMO in accordance with the following formula:

$A \times B$

Where A = that Market Participant's constrained on injection quantity for that adjusted bid step for the first operating schedule in the gas day at that controllable injection point determined under clause 7.1,

B = an amount of compensation expressed in $/GJ equal to the greater of:

(a)   zero; and

(b)   the bid price for the adjusted bid step in the first operating schedule less the market price applicable for the first operating schedule in the gas day.

For the avoidance of doubt, a positive initial injection ancillary payment represents a payment from AEMO to a Market Participant.

If gas within that adjusted bid step was nominated by that Market Participant as an uplift hedge or gas was injected by that Market Participant without that injection being accredited by AEMO in accordance with the Rules, the amount of the initial injection ancillary payment for that adjusted bid step must be zero.

7.4.2 Calculation of initial ancillary payments for each updated operating schedule of the gas day

The initial injection ancillary payment (if any) payable to a Market Participant for each controllable injection point for each adjusted bid step for each updated schedule is calculated in accordance with the following formula:

$(A - B) \times C$

Where:

A = that Market Participant's constrained on injection quantity for that adjusted bid step for the current operating schedule at that controllable injection point as determined under clause 7.1;

B = that Market Participant's constrained on injection quantity for that adjusted bid step for the previous operating schedule at that controllable injection point as determined under clause 7.1;

C = an amount of compensation expressed in $/GJ equal to the greater of:

(a)   zero; and

(b)   the current operating schedule bid price for that adjusted bid step less the current pricing schedule market price.

For the avoidance of doubt, a positive initial injection ancillary payment value represents a payment from AEMO to a Market Participant.

If a quantity of gas within an adjusted bid step was nominated by that Market Participant as an uplift hedge or gas was injected by that Market Participant without that injection being accredited by AEMO in accordance with the Rules, the initial injection ancillary payment for that adjusted bid step must be zero.

7.4.3 Calculation of revised injection ancillary payments for the initial operating schedule of the gas day

The revised injection ancillary payment payable to a Market Participant for each adjusted bid step for the initial operating schedule in the gas day at a controllable injection point equals the initial injection ancillary payment payable to that Market Participant for that controllable injection point and for that adjusted bid step as determined under clause 7.4.1.

7.4.4 Calculation of revised injection ancillary payments for each updated operating schedule of the gas day

The revised injection ancillary payment payable to a Market Participant for each controllable injection point and for each adjusted bid step for the updated operating schedule in the gas day equals:

(a)   the initial injection ancillary payment for that adjusted bid step for that current schedule for that Market Participant at that controllable injection point as determined under clause 7.4.1 if this value is greater than or equal to zero.

(b)   Otherwise, the sum over all previous operating schedules in the gas day of:

(i)   the negative of that Market Participant's matched change in constrained on injection quantity of the current schedule and the relevant prior schedule as determined under clause 7.3.1 multiplied by an amount ($/GJ) of compensation defined as the greater of:

(A)   zero; and

(B)   the lesser of the bid price for the adjusted bid step in the current operating schedule and the bid price for that adjusted bid step in the relevant prior operating schedule

(C)   less the market price applicable for the current operating schedule.

For the avoidance of doubt, a positive revised injection ancillary payment value represents a payment from AEMO to a Market Participant.

If a quantity of gas within an adjusted bid step was nominated by that Market Participant for an uplift hedge or gas was injected by that Market Participant without that injection of gas being accredited by AEMO under the Rules, the amount of the revised injection ancillary payment for that adjusted bid step must be equal to zero.

7.4.5 Calculation of final injection ancillary payments for the initial schedule of the gas day

The final injection ancillary payment payable to a Market Participant for each adjusted bid step for the first operating schedule in the gas day at each controllable injection point is equal to the revised injection ancillary payment payable to that Market Participant under clause 7.4.3.

For the avoidance of doubt, the calculations in clause 7.4.3 and this clause do not change the initial ancillary payment payable to a Market Participant for each adjusted bid step for the first operating schedule in the gas day at each controllable injection point.

7.4.6 Calculation of final injection ancillary payments for each updated schedule of the gas day

The final injection ancillary payment payable to a Market Participant for each controllable injection point for each adjusted bid step for each updated operating schedule in the gas day is:

(a)   the revised injection ancillary payment payable to that Market Participant for that controllable injection point and adjusted bid step for the current schedule if not all of the following conditions are met :

o the sum of all revised injection ancillary payments to all Market Participants for all controllable injection points and all adjusted bid steps for the current operating schedule is greater than zero;

o the initial injection ancillary payment payable to that Market Participant for the current operating schedule is less than zero;

o not all revised injection ancillary payments equal the corresponding initial injection ancillary payments payable to each Market Participant for all controllable injection points, and adjusted bid steps for the updated schedule;

Otherwise, it is

(b) the greater of

o the initial injection ancillary payment payable to that Market Participant; and

o the revised injection ancillary payment payable to that Market Participant plus an amount calculated as the average rate of ancillary payment multiplied by that Market Participant's change in constrained on injection quantity for the current operating schedule.

For the purposes of the above calculation, the average rate of ancillary payment is the sum of all revised injection ancillary payments across all Market Participants, all controllable injection points and all adjusted bid steps for the current operating schedule divided by the greater of:

- the sum over all Market Participants, all controllable injection points and all adjusted bid steps for the current operating schedule of the sum of all positive changes in constrained on injection quantity for the current operating schedule; and

- negative one multiplied by the sum over all Market Participants, all controllable injection points and all adjusted bid steps for the current operating schedule of the negative changes in constrained on injection quantity for the current operating schedule.

7.5 Calculation of ancillary payments for withdrawal quantities

7.5.1 Calculation of initial withdrawal ancillary payments for the initial operating schedule of the gas day

The initial withdrawal ancillary payment payable to each Market Participant, for each controllable withdrawal point for each adjusted bid step for the first operating schedule in the gas day is:

A x B

Where:

A = that Market Participant's constrained on withdrawal quantity for that adjusted bid step for the first operating schedule in the gas day at each controllable withdrawal point as determined under clause 7.2; and

B = an amount of compensation expressed in $/GJ which is the greater of:

(i) zero; and

(ii) the market price less the bid price for the adjusted bid step in the first operating schedule of the gas day.

For the avoidance of doubt, a positive initial withdrawal ancillary payment represents a payment from AEMO to a Market Participant.

If gas was withdrawn by that Market Participant without that withdrawal being accredited by AEMO under the Rules, the amount of initial withdrawal ancillary payment payable to that Market Participant for that adjusted bid step is zero.

7.5.2 Calculation of initial withdrawal ancillary payments for each updated schedule of the gas day

The initial withdrawal ancillary payment payable to a Market Participant for each controllable withdrawal point and for each adjusted bid step for each updated schedule is:

(A – B) x C

Where:

A = the constrained on withdrawals by that Market Participant for that adjusted bid step for the current operating schedule at each controllable withdrawal point as determined for that Market Participant under clause 7.2

B = the constrained on withdrawals by that Market Participant for that adjusted bid step for the previous operating schedule at each controllable withdrawal point as determined under clause 7.2

C = an amount of compensation expressed as $/GJequal to the greater of:

(i)   zero; and

(ii)   the current pricing schedule market price less the current operating schedule bid price for that adjusted bid step.

For the avoidance of doubt, a positive ancillary payment represents a payment from AEMO to a Market Participant.

If gas was withdrawn by that Market Participant without that withdrawal being accredited by AEMO under the Rules, the ancillary payment payable to that Market Participant for that adjusted bid step is zero.

7.5.3 Calculation of revised withdrawal ancillary payments for the initial schedule of the gas day

The amount of revised withdrawal ancillary payment determined for each Market Participant, for each controllable withdrawal point for each adjusted bid step for the first operating schedule in the gas day is equal to the initial withdrawal ancillary payment for that adjusted bid step for the first operating schedule in the gas day for that Market Participant at that controllable withdrawal point as determined under clause 7.5.1.

7.5.4 Calculation of revised withdrawal ancillary payments for each updated schedule of the gas day

The amount of revised withdrawal ancillary payment for each Market Participant, for each controllable withdrawal point and for each adjusted bid step for the updated operating schedule in the gas day is determined as:

(a)   the initial withdrawal ancillary payment for that adjusted bid step for that current operating schedule for that Market Participant at that controllable withdrawal point as determined under clause 7.5.2 if this value is greater than or equal to zero.

(b)   otherwise, the sum over all prior schedules in the gas day of:

(i)   the negative of the matched change in constrained on withdrawal quantity of the current operating schedule and the relevant prior operating schedule as determined under clause 7.3.1 multiplied by a per unit amount of compensation defined as the greater of

(ii)   zero; and

(iii)   the lesser of the bid price for the adjusted bid step in the current operating schedule and the bid price for that adjusted bid step in the relevant prior operating schedule

(iv)   less the market price for the current operating schedule.

For the avoidance of doubt, a positive revised withdrawal ancillary payment value represents a payment from AEMO to a Market Participant.

If:

- a quantity of gas within an adjusted bid step was nominated as an uplift hedge; or

- gas was withdrawn without that withdrawal being accredited by AEMO under the Rules,

then the revised withdrawal ancillary payment for that adjusted bid step is equal to zero.

7.5.5 Calculation of final withdrawal ancillary payments for the initial schedule of the gas day

The amount of final withdrawal ancillary payment to be paid to each Market Participant, for each controllable withdrawal point for each adjusted bid step for the first operating schedule in the gas day is equal to the revised withdrawal ancillary payment.

7.5.6 Calculation of final withdrawal ancillary payments for each updated schedule of the gas day

The final withdrawal ancillary payment payable to a Market Participant for each controllable withdrawal point for each bid step for the updated schedule in the gas day is determined as:

(a)   the revised withdrawal ancillary payment payable for that Market Participant, controllable withdrawal and bid step for the current operating schedule if not all of the following conditions are met:

- o   the sum of all revised withdrawal ancillary payments across all Market Participants, controllable withdrawal points and all adjusted bid steps for the current operating schedule is greater than zero;

- o   the initial withdrawal ancillary payment payable to that Market Participant for the current operating schedule is less than zero; and

    not all revised withdrawal ancillary payments equal the corresponding initial withdrawal ancillary payment for each Market Participant,

controllable withdrawal point, and adjusted bid step for the updated schedule.

(b)   otherwise, it is the greater of

o   the initial withdrawal ancillary payment payable to that Market Participant; and

o   the revised withdrawal ancillary payment payable to that Market Participant plus an amount calculated as the average rate of ancillary payment multiplied by the value of the change in constrained on withdrawal quantity for the current operating schedule.

For the purposes of the above calculation, the average rate of ancillary payment is the sum of all revised withdrawal ancillary payments across all Market Participants, all controllable withdrawal points and all adjusted bid steps for the current operating schedule divided by the greater of:

•   the sum over all Market participants, controllable withdrawal points and all adjusted bid steps for the current operating schedule of the sum of all positive changes in constrained on withdrawal quantity for the current operating schedule; and

•   negative one multiplied by the sum over all Market Participants, controllable withdrawal points and all adjusted bid steps for the current operating schedule of the negative changes in constrained on withdrawal quantity for the current operating schedule.

7.5.7 Calculation of Average Ancillary Payments rates

The average rates for positive and negative ancillary payments are calculated for each schedule and used to limit the positive and negative uplift rates ($/GJ) which are incurred by any Market Participant or the declared transmission service provider. Any residual or excess uplift, whether positive or negative, is to be allocated to common uplift. Refer to clause 8 in the Wholesale Market (Uplift Payment) Procedures which sets out how these uplift caps are applied in the uplift process.

The average rate for positive ancillary payments (*positive average ancillary payment rate*) for a schedule is determined by:

the sum of the positive final ancillary payments across all Market Participants, all controllable injection and withdrawal points and all bid steps for that schedule

divided by

the sum of the positive changes in constrained up injection and withdrawal quantities across all Market Participants, controllable injection and withdrawal points and all bid steps for that schedule.

The average rate for negative ancillary payments (negative average ancillary payment rate) is determined for each schedule by:

the sum of the negative final ancillary payments across all participants, controllable injection and withdrawal points and all bid steps for the schedule

divided by

the sum of the negative changes in constrained up injection and withdrawal quantities across all participants, controllable injection and withdrawal points and all bid steps for the schedule.

The positive average ancillary payment rate and the negative average ancillary payment rate are positive values.

SCHEDULE 3

AGL compensation

							excl GST	GST	incl GST
Company:	AGL					Total compensation	$21,583.28	$2,158.33	$23,741.61

Bid	Bid Price ($/GJ)	Bid Quantity (GJ)	OS quantity (GJ) by adj bidstep	Modified PS quantity (GJ)	AGINO (allocated under-injection) (GJ)	CUIQ Comon quantity (GJ)	ACUIQ Change in comon quantity (GJ)	Compensation $ excl GST
				Schedule	1		Market Price	$1.1069
1	$0.0000	0	0		0	0	0	$0
2	$0.0000	111,000	111,000	111,000	8,972	0	0	$0
3	$3.5000	111,000	111,000	0	0	0	0	$0
4	$3.5000	121,000	10,000	0	0	10,000	10,000	$23,931
5	$4.1100	121,000	0	0	0	0	0	$0
6	$4.9900	141,000	0	0	0	0	0	$0
7	$123.4567	191,000	0	0	0	0	0	$0
8	$765.4321	241,000	0	0	0	0	0	$0
Total		241,000	121,000	111,000	8,972	10,000	10,000	$23,931

		Operating schedule quantity (GJ)					
mirn	30000001PC						
sched_no	S1	S2	S3	S4	S5(final)	Actual (GJ)
06:00 AM	6,600	6,600	6,600	6,600	6,600	5,149
07:00 AM	4,974	4,974	4,974	4,974	4,974	5,850
08:00 AM	4,974	4,974	4,974	4,974	4,974	6,614
09:00 AM	4,974	4,974	4,974	4,974	4,974	7,285
10:00 AM	4,974	6,166	6,166	6,166	6,166	7,475

SCHEDULE 4

OE compensation

			Total compensation	GST	amount incl GST
			$46,234.58	$4,623.46	$50,858.04

Company: Origin Energy

Adjusted bid step	Bid Price ($/GJ)	Adj Bid Quantity (GJ)	OS quantity (GJ)	Modified PS quantity (GJ)	AGINO* (allocated under-injection) (GJ)	CUIQ = Comp'n quantity (GJ)	ΔCUIQ = Change in comp'n quantity (GJ)	Compensation $ excl GST
Schedule 1							Market Price	$1.1069
1	$0.0001	16	16	16	0	0	0	$0
2	$0.3889	12,228	12,212	12,212	0	0	0	$0
3	$1.1069	12,234	6	6	0	0	0	$0
4	$3.4869	19,073	6,839	0	6,839	6,839	6,839	$16,277
5	$3.7769	20,000	927	0	927	927	927	$2,475
6	$3.7769	35,705	14,538	0	4,244	10,293	10,293	$27,483
Total			34,538	12,234	4,244	18,059	18,059	$46,235
Schedule 2							Market Price	$2.8700
1	$0.0001	16	16	16	0	0	0	$0
2	$0.3889	12,228	12,212	12,212	0	0	0	$0
3	$1.1069	12,234	6	6	0	0	0	$0
4	$3.4869	19,073	6,839	6,839	0	6,839	6,839	$0
5	$3.7769	20,000	927	927	0	927	927	$0
6	$3.7769	35,705	15,705	15,705	5,412	10,293	10,293	$0
Total			35,705	12,234	5,412	18,059	18,059	$0
Schedule 3							Market Price	$3.1000
1	$0.0001	16	16	16	0	0	0	$0
2	$0.3889	20,000	19,984	19,984	0	0	0	$0
3	$0.3889	20,000	0	0	0	0	0	$0
4	$0.3889	20,000	0	0	0	0	-6,839	$0
5	$0.3889	20,000	0	0	0	0	-927	$0
6	$2.8700	35,705	15,705	15,705	5,412	0	-10,293	$0
Total			35,705	15,705	5,412	18,059	-18,059	$0
Schedule 4							Market Price	$3.4800
1	$0.0001	16	16	16	0	0	0	$0
2	$0.3889	20,000	19,984	19,984	0	0	0	$0
3	$0.3889	20,000	0	0	0	0	0	$0
4	$0.3889	20,000	0	0	0	0	0	$0
5	$0.3889	20,000	0	0	0	0	0	$0
6	$2.8700	35,705	15,705	15,705	5,412	0	0	$0
Total			35,705	15,705	5,412	0	0	$0
Schedule 5							Market Price	$3.2121
1	$0.0001	16	16	16	0	0	0	$0
2	$0.3889	20,000	19,984	19,984	0	0	0	$0
3	$0.3889	20,000	0	0	0	0	0	$0
4	$0.3889	20,000	0	0	0	0	0	$0
5	$0.3889	20,000	0	0	0	0	0	$0
6	$2.8700	35,705	15,705	15,705	5,412	0	0	$0
Total			35,705	15,705	5,412	0	0	$0

* AGINO = actual gas injecton negative offset
* CUIQ = constrained up injectin quantity (which is eligible for compensation)

mim 3000001PC

sched_no	Operating schedule quantity (GJ)					
	S1	S2	S3	S4	S5 final	Actual (GJ)
06:00 AM	371	371	371	371	371	1,467
07:00 AM	1,486	1,486	1,486	1,486	1,486	1,576
08:00 AM	1,486	1,486	1,486	1,486	1,486	1,842
09:00 AM	1,486	1,486	1,486	1,486	1,486	2,077
10:00 AM	1,486	1,841	1,841	1,841	1,841	2,143
11:00 AM	1,486	1,841	1,841	1,841	1,841	2,124
12:00 PM	1,486	1,841	1,841	1,841	1,841	2,119
01:00 PM	1,486	1,841	1,841	1,841	1,841	2,099
02:00 PM	1,486	1,469	1,821	1,821	1,821	2,306
03:00 PM	1,486	1,469	1,821	1,821	1,821	2,259
04:00 PM	1,486	1,469	1,821	1,821	1,821	1,816
05:00 PM	1,486	1,469	1,821	1,821	1,821	815
06:00 PM	1,486	1,469	1,821	1,821	1,821	949
07:00 PM	1,486	1,469	1,309	1,309	1,309	970
08:00 PM	1,486	1,469	1,309	1,309	1,309	942
09:00 PM	1,486	1,469	1,309	1,309	1,309	943
10:00 PM	1,486	1,469	1,309	1,309	1,309	928
11:00 PM	1,486	1,469	1,309	1,309	1,309	926
12:00 AM	1,486	1,469	1,309	1,309	1,309	844
01:00 AM	1,486	1,469	1,308	1,309	1,309	863
02:00 AM	1,486	1,469	1,309	1,309	1,309	869
03:00 AM	1,486	1,469	1,309	1,309	1,309	889
04:00 AM	1,486	1,469	1,309	1,309	1,309	903
05:00 AM	1,486	1,469	1,309	1,309	1,309	877
Total	34,538	35,705	35,705	35,705	35,705	33,547

Scheduling Interval	final OS GJ	Actual GJ	Effective actual (GJ)
1	4,827	6,961	4,827
2	7,366	8,486	7,366
3	7,286	7,196	7,196
4	5,750	3,805	3,805
5	10,476	7,100	7,100
Total	35,705	33,547	30,293

Effective actual allocated to adjusted bid steps (GJ)

16
19,984
0
0
0
10,293
Total 30,293