TECHNICAL GUIDE TO THE VICTORIAN DECLARED WHOLESALE GAS MARKET

JUL 2013

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

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History

This guide replaces the *Technical Guide to the Victorian Gas Wholesale Market*, last published May 2012.

Version	Date	Changes
1.0	May 2012	Revised and updated for May 2012 release of market systems.
1.1	July 2013	The map of the Declared Transmission System (Figure 2-1) was updated to reflect the new Euroa Compressor Station. Figure Figure 2-2 was updated to reflect the latest daily withdrawal compositions since January 2011.

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Abbreviations and Symbols

Abbreviation	Term
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMDQ	authorised maximum daily quantity (collective term for authorised MDQ and AMDQ credits)
AMIQ, AMIQ%	authorised maximum interval quantity (GJ) or percentage profile (%)
AGINO	actual gas injection negative offset
AP	ancillary payment
CUIQ	constrained-up injection quantity
DFS	Demand Forecasting System
DP	deviation payment

Abbreviation	Term
DTS	Declared Transmission System
DTSSP	Declared Transmission System Service Provider
EST	Eastern Standard Time
GJ	gigajoule is a unit of measure of energy equal to 10^9 joule
GMS	Gas Market System
GPG	gas-fired power generator
GRCF	Gas Retail Consultative Forum
GWCF	Gas Wholesale Consultative Forum
IP	imbalance payment
ITPSP	interconnected transmission pipeline service provider
LNG	liquefied natural gas (also used to refer to the Dandenong LNG storage facility)
LPA	linepack account
MCE	Market Clearing Engine
MDA	metering data agent
MDQ	maximum daily quantity
MHQ	maximum hourly quantity
MIBB	Market Information Bulletin Board
MMS	Metering and Settlements System
MP	market participant
NGL	National Gas Law
NGR	National Gas Rules
PBR	2003–04 Pricing and Balancing Review
PJ	petajoule is a unit of measure of energy equal to 10^{15} joule
PTS	Principal Transmission System (obs.)
SCADA	supervisory control and data acquisition
SEA	Service Envelope Agreement
TJ	terajoule is a unit of measure of energy equal to 10^{12} joule
TMM	Transportation and Market Manager
UAFG	unaccounted-for-gas
UH	uplift hedge
UP	uplift payment

Preface

This guide explains the workings of the Declared Wholesale Gas Market and provides a technical overview for participants and others interested in gaining a stronger understanding of its operation. This guide is not intended as a substitute for published procedures and specifications.

A comprehensive list of the terms used in this guide is provided in Appendix A. The format of these terms follows generally accepted standards and conventions. In particular, technical terms such as linepack, market participant, and service provider are, in general, not capitalised nor italicised. This might vary from the formats adopted in other references, but the addition or omission of such ornamentation is not intended to imply a difference in the definition nor interpretation of the term.

Specifically, capitalisation in this guide indicates that the term is either a formal title (Declared Transmission System, for example) or the formal name of a facility or place (Dandenong City Gate, for example) or a formal class of agreement, market state, limit, or operating condition (Service Envelope Agreement and Tariff D, for example). Whereas italic indicates that the term is a published title, such as an act of parliament, another AEMO publication, or a publication from another source.

The publications cited in this guide are listed in Appendix B and take the form *published title* [reference].

1 Introduction

Victorian businesses and households have relied on natural gas as a major source of energy since it was first rolled out in the state in the late 1960s. Growing needs have led to more sophisticated requirements. In particular, clearer supply and demand signals have been required to enable the energy sector to operate more efficiently, and in March 1999 a wholesale gas market was introduced. This has facilitated gas trading within Victoria.

There are now more than 2 million Victorian natural gas customers, and annual demand for natural gas (excluding that from gas-fired generators) exceeds 200 petajoules (PJ). Annual residential use of natural gas, driven by winter heating and hot water needs, exceeds 90 PJ—by far the highest in the country. In addition, annual demand from gas-fired generation has exceeded 30 PJ and is expected to grow considerably, in line with efforts to reduce the carbon emissions from electricity production.

The energy sector has continued to evolve, requiring a review of the operation of the market. This detailed study revealed the need for updates to be made and, in February 2007, a new wholesale market commenced operation.

In this guide:

- Chapter 2 provides an overview of the Victorian Declared Wholesale Gas Market (DWGM), gas transportation rights, and governance through consultative committees and the National Gas Rules.

- Chapter 3 explains the roles of participants in the DWGM and the inter-relationships.

- Chapter 4 explains how gas is traded in the market and an overview of the key DWGM processes.

- Chapter 5 provides an overview of the DWGM market (IT) systems.

- Chapter 6 explains the concept of authorised maximum daily quantity (AMDQ) and the physical and financial benefits it provides.

- Chapter 7 provides an overview of the gas scheduling process, and the roles and obligations of AEMO and market participants in relation to this process.

- Chapter 8 provides an overview of the metering process.

- Chapter 9 provides an overview of the gas settlement process.

- Chapters 10 to 15 explain the calculations of the various market payments.

- The appendices include a glossary of terms, reference documents, and more detailed process diagrams.

2 Overview of the DWGM

This chapter provides a high-level overview of the Victorian Declared Wholesale Gas Market (DWGM)—the formal title for the Victorian gas wholesale market—AEMO's role in its operation, the drivers for supply and demand, the contractual basis for transporting gas through the transmission system, and what governs the operation of the market.

In this chapter:

- A brief history

- The role of AEMO

- Victorian DWGM coverage

- Supply and demand in the DWGM

- Transportation rights

- The National Gas Rules

2.1   A brief history

The Declared Wholesale Gas Market (DWGM) started in March 1999 and was designed to:

- Manage gas supply, demand and linepack of the Victorian Declared Transmission System (DTS)—previously known as the Principal Transmission System (PTS).

- Facilitate trading of natural gas by market participants (MPs).

- Set a daily (ex post) gas price for all trades.

The DWGM was reviewed in 2001 and again in 2003–04 through an extensive consultation process with participants operating in the DWGM at those times. The 2003–04 review, also known as the Pricing and Balancing Review (PBR), aimed to:

- Provide more efficient and transparent pricing signals.

- Improve market interaction and response to pricing signals.

- Provide adequate incentives and flexibility for demand-side response.

- Facilitate investment in pipeline infrastructure.

The PBR considered a three-stage development of the DWGM. It recommended the following changes in the first stage, which have been implemented in the current DWGM:

- Move the gas day start time to 6 AM EST (moved forward from 9 AM in the previous market).

- Provide ex ante pricing for each schedule to give pricing certainty (previously daily day-after or ex post pricing).

- Provide five schedules during the gas day at 6 AM, 10 AM, 2 PM, 6 PM, and 10 PM, plus ad hoc schedules if required.

- Allow rebidding of prices and quantities and updates to demand forecasts for schedules after the first schedule.

- Require market participants (MPs) to pay deviation payments if they deviated (under-injected or over-withdrew) from their scheduled quantities in each scheduling interval.

- Pay or be paid imbalance payments at the market price for the differences between an MP's scheduled injections and withdrawals.

- Allocate ancillary payments and uplift costs in a way that better reflected who was responsible for causing them.

2.2   The role of AEMO

The Australian Energy Market Operator (AEMO) commenced operations on 1 July 2009 and delivers an array of gas and electricity market, operational, development, and planning functions. AEMO's primary responsibilities include management of the National Electricity Market (NEM) and the retail and wholesale gas markets of eastern and southern Australia. AEMO also oversees system security of the national electricity grid and the Victorian gas transmission network.

Specifically, in Victoria, AEMO performs the following roles in the DWGM:

- Operates the Declared Transmission System (DTS).

- Operates and administers the DWGM.

- Maintains system security for the DTS so as to minimise the threats to system security.

- Monitors trading activity in the DWGM and reports significant price variations in the market.

For more information about AEMO's gas market roles and responsibilities, refer to *The Victorian Gas Industry Act* [42]and *National Gas (South Australia) Act* 2008 (The National Gas Law) [43].

2.3   Victorian DWGM coverage

2.3.1   The Declared Transmission System

The area serviced by the Declared Transmission System (DTS) is shown in Figure 2-1. The DTS is a complex network of high-pressure transmission pipelines with a total length of some 2,000 kilometres [45]. The DTS extends from Longford in the east of Victoria, to Portland in the south-west, across central Victoria, and north to Albury-Wodonga and Culcairn in New South Wales.

The major pipelines that make up the DTS are:

- Longford–Melbourne pipeline (Longford–Dandenong–Wollert)

- South West Pipeline (Iona–Lara–Brooklyn)

- Wollert–Albury-Wodonga pipeline

- The Interconnect (to NSW)

- Western Transmission System (WTS) from Iona to Portland (integrated into the DTS in 2003).

Other transmission pipelines, which are not part of the DTS, connect the DTS to NSW, Tasmania, and South Australia; to gas production and storage facilities; and to other distribution systems:

- Eastern Gas Pipeline (EGP) (Longford–Wollongong–Sydney)

- Minerva–Iona pipeline (SEA Gas adjunct)

- BassGas pipeline (Lang Lang Gas Plant – Pakenham)

- Carisbrook–Horsham pipeline

- Culcairn–Wagga–Young pipeline (NSW system)

- SEA Gas pipeline (Iona–Adelaide)

- Tasmanian Gas Pipeline (Longford – Bell Bay)
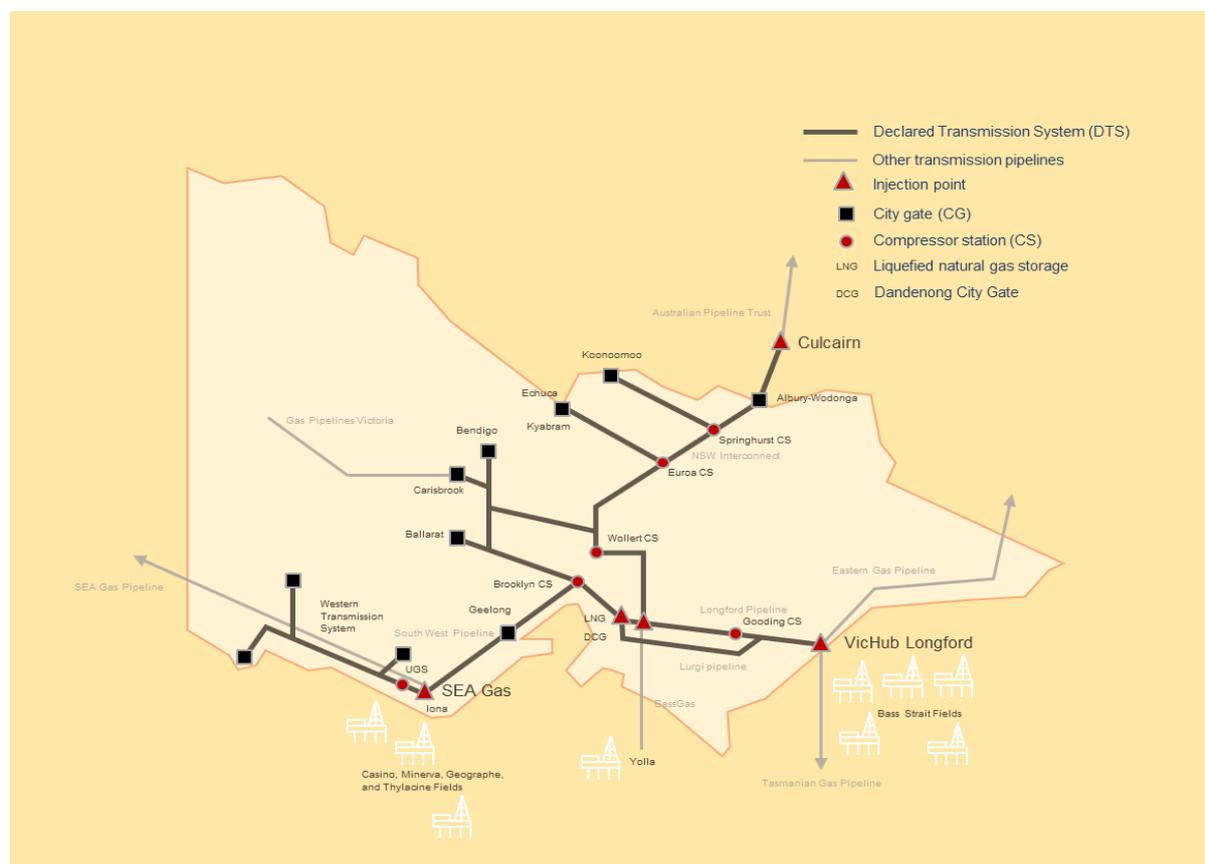
Figure 2-1   Map of the Declared Transmission System

2.3.2 Injection and withdrawal points

There are more than 120 withdrawal points in the DTS that allow gas to flow from the DTS into the Victorian distribution networks, to large gas customers, into storage facilities, or interstate. These are supplied by injection points that allow gas to flow from production fields, production plants, storage facilities, and other transmission pipelines into the DTS. The injection points to the DTS (see Figure 2-1) are:

- Longford and VicHub—located at Longford. Gas is supplied from the Bass Strait gas fields and to or from the EGP at VicHub.

- BassGas—located at Pakenham. Gas is supplied from the Lang Lang gas plant.

- LNG (liquefied natural gas) facility—located at Dandenong. Gas is supplied from the LNG storage and processing plant at Dandenong.

- Otway, Mortlake and SEA Gas—all located near Port Campbell. Gas is supplied from the Casino, Minerva, Thylacine and Geographe gas fields.

- Iona—located near Port Campbell. Gas is supplied to or from the Underground Gas Storage (UGS) facility.

- Culcairn (The Interconnect)—connects NSW and Victoria. Gas is supplied to or from the EAPL (NSW) system.

The VicHub, Iona and Culcairn injection points are bi-directional—that is, gas can flow into or out of the DTS at these points. BassGas and SEA Gas usually act as injection points but can also withdraw gas for operational purposes or during an emergency.

For more information about the facilities that make up the DTS, refer to the *Victorian Annual Planning Report* [4].

2.4 Supply and demand in the DWGM

Annual demand on the DTS is approximately 230 petajoules (PJ). Gas transported through the DTS supplies a variety of needs, including:

- Residential, business and industrial customers.

- Gas-fired power generators (GPG)—there are currently five plants connected to the DTS.

- Exports to NSW, Tasmania, and South Australia through the interconnected pipelines.

- Underground storage (UGS) at Iona and LNG storage at Dandenong.

2.4.1 Daily demand

Daily gas demand is typically up to 100 TJ higher on weekdays than weekends with comparable weather conditions. Demand on weekends is lower due to reduced loads from industrial and commercial consumers. Figure 2-2 depicts the daily gas withdrawals (demand) from the DTS during 2009–2011. The record daily gas withdrawal was 1,280 TJ in July 2007.

Gas withdrawals over a gas day typically peak in the morning between 7 AM and 8 AM and in the evening between 6 PM and 7 PM and are lowest overnight. This peaking is more pronounced on winter days, as shown in Figure 2-2. In contrast, injections are relatively flat over the gas day but are subject to rescheduling.

The pressurised gas stored in the pipeline is called the "linepack". The change in linepack through the gas day is equal to the cumulative difference between injections and withdrawals. As shown in Figure 2-3, linepack is typically high at the beginning of the gas day (ideally, close to the daily "linepack target") and is lowest around 10 PM in the evening.

2.4.2   Controllable injections and withdrawals

On any given gas day, market participants (MPs) trade in the gas market based on the imbalance between the gas withdrawn by their customers and the gas they injected into the DTS. MPs can control the quantity of gas injections, and so injections are "controllable". However, it is not possible to control the quantity of gas used by most end-use customers.

There are two categories of withdrawals:

*   **Controllable withdrawals.** This refers to price-dependent quantities of gas that MPs withdraw based on the price they bid in the market. In the current gas market, interstate exports and gas withdrawn into the UGS are controllable.

*   **Uncontrollable withdrawals.** This refers to the quantities of gas that MPs withdraw regardless of the market price. This applies to almost all customers in the residential, commercial and industrial sectors. Note that uncontrollable withdrawals also include demand from gas-fired power generators (GPG).
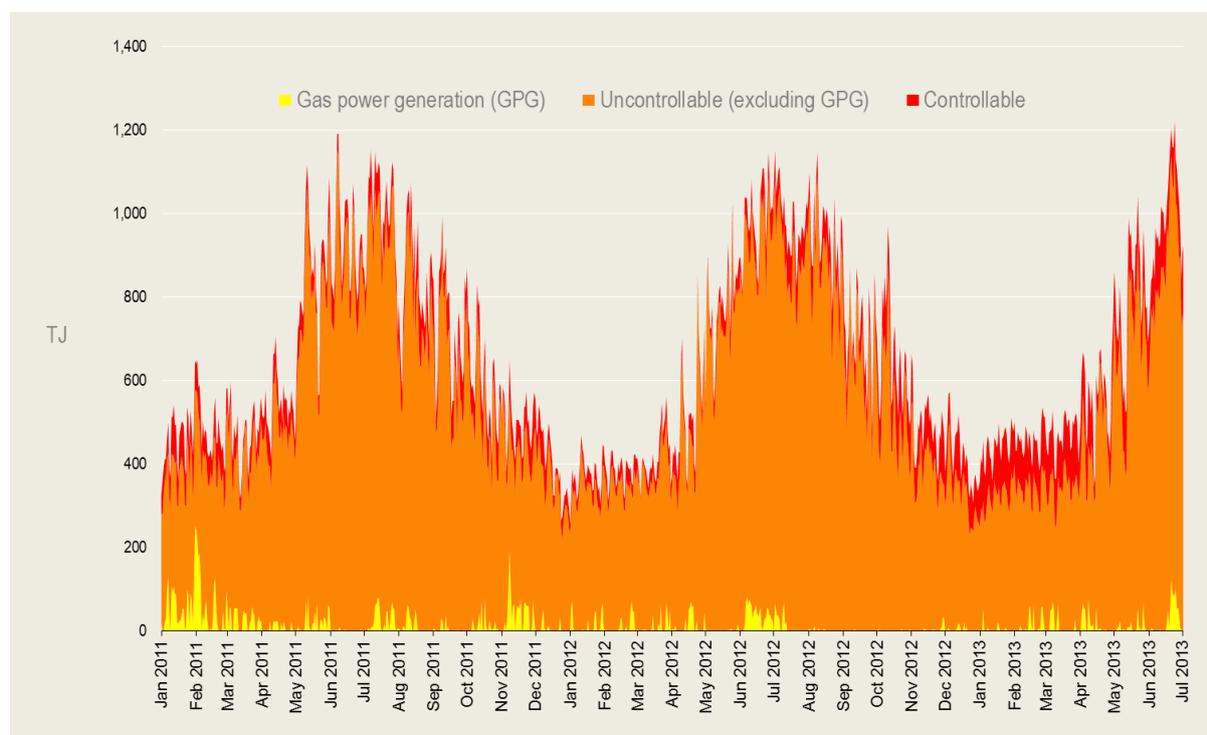
Figure 2-2   Daily market gas withdrawal during the 2011–2013 period
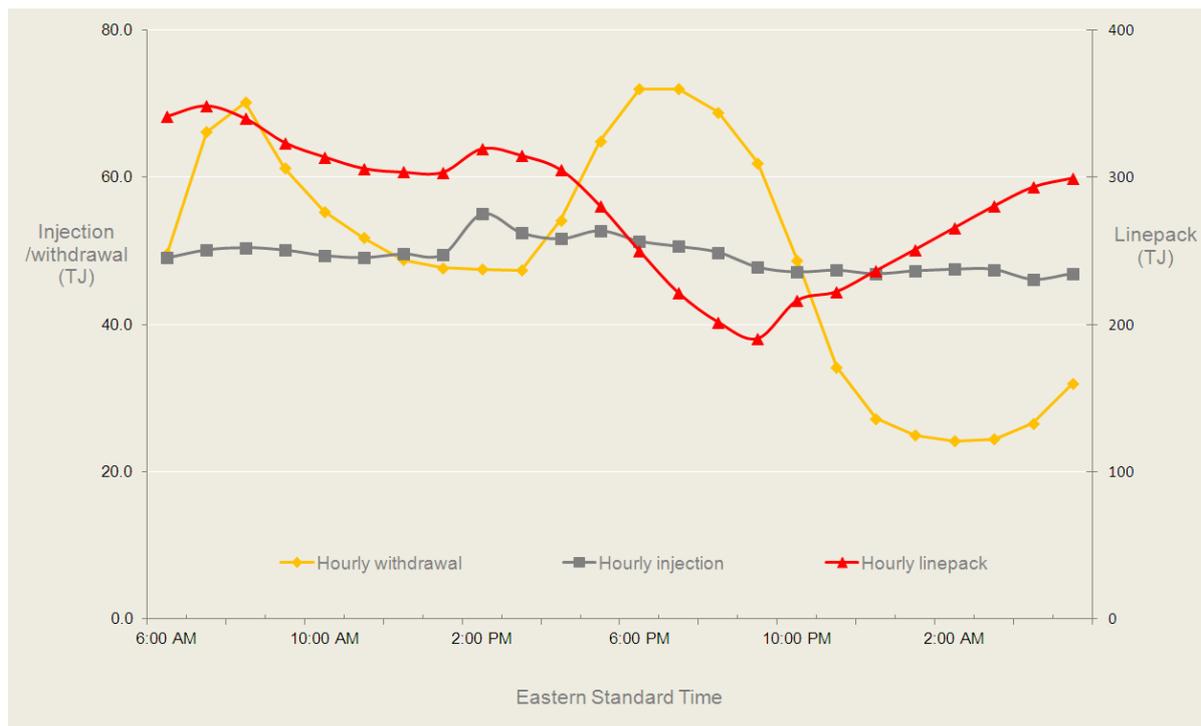
Figure 2-3   Injections, withdrawals and system linepack

2.5   Transportation rights

AEMO, the operator of the DTS, and APA-GasNet, the pipeline facility owner, have entered into a Service Envelope Agreement (SEA) that determines, amongst other things, the transportation capacity of the DTS and the obligations of each party. The SEA covers the Longford–Melbourne Pipeline (the original pipeline), The Interconnect, and newer additions to the DTS (SWP, WTS, and such).

When the Victorian DWGM commenced, AEMO (then VENCorp) allocated the transportation rights on the Longford–Melbourne pipeline system (including The Interconnect, Wimmera pipeline, and Murray Valley towns) individually to Tariff D (large) customers and collectively to Tariff V (residential and small-to-medium commercial and industrial) customers in the form of an "authorised MDQ" (maximum daily quantity). Authorised MDQ transport rights are associated with the original peak capacity (990 TJ per day) of the Longford system.

Subsequently, MPs have contracted directly with APA-GasNet for the capacity on new pipelines and any additional capacity on the Longford–Melbourne pipeline. These later transportation rights are known as "AMDQ credits", which are issued by AEMO at the direction of the pipeline owner.

MPs and Tariff D customers transport gas through the DTS based on these authorised MDQ and AMDQ credits—collectively known as "AMDQ" or "transportation rights". They provide MPs with preferential rights to inject gas into and withdraw gas from the DTS plus certain financial benefits.

For information on how AMDQ are allocated, acquired, and transferred, see Chapter 6.

2.6   The National Gas Rules

The National Gas Rules (NGR) govern access to natural gas pipeline services and broader elements of natural gas markets. An amended version of the NGR, which authorises AEMO, was passed in the South Australian parliament and came into effect on 1 July 2009. The NGR carries the force of the National Gas Law (NGL).

The NGR sets out the processes by which the gas markets are operated and the responsibilities and obligations of the market participants. The parts of the NGR that are relevant to the DWGM are listed in Table 2.1.

The objectives of the NGR are to:

- Facilitate efficient, competitive and reliable gas markets.

- Regulate the operation and administration of the gas markets.

- Regulate activities of participants in the gas markets.

- Provide for access to the DTS and ensure its security.

Table 2.1   Guide to the parts of the NGR

Purpose	NGR
Requirements for participation in the gas market	Part 15A, Division 1
Gas scheduling process	Part 19, Division2, Subdivision 2
Market participants' nominations and bidding processes	Part 19, Division 2, Subdivision 2
Determination of gas market prices	Part 19, Division 2, Subdivision 3
Metering and settlement processes of the gas market	Part 19, Division 2, Subdivision 5 and 6
Monitoring market participants' prudential requirements	Part 19, Division 2, Subdivision 7
Publication of market and planning information	Part 19, Division 4
Management of emergency, market suspension and system security threats	Part 19, Division 5
Dispute resolution	Part 15C and Part 19, Division 6
The rule change process	Part 19, Division 8

2.7   Market consultative forums

Changes to market design, market rules, and material changes to key procedures are initiated through consultative forums. These forums are related in the sense that changes to the wholesale gas rules can impact on the operation of the retail market, and vice versa. The rule change process is outlined in Figure 2-4.

Gas Wholesale Consultative Forum

The Gas Wholesale Consultative Forum (GWCF), comprising representatives from the gas industry, considers and makes submissions to the AEMO Board on issues relating to the development or operation of the gas market and any consequential changes to the National Gas Rules (NGR).

Gas Retail Consultative Forum

The Gas Retail Consultative Forum (GRCF), comprising representatives from the gas industry, advises the AEMO Board in its management of the retail rules.

Refer to the AEMO website for details about the roles and membership of the GWCF and GRCF.
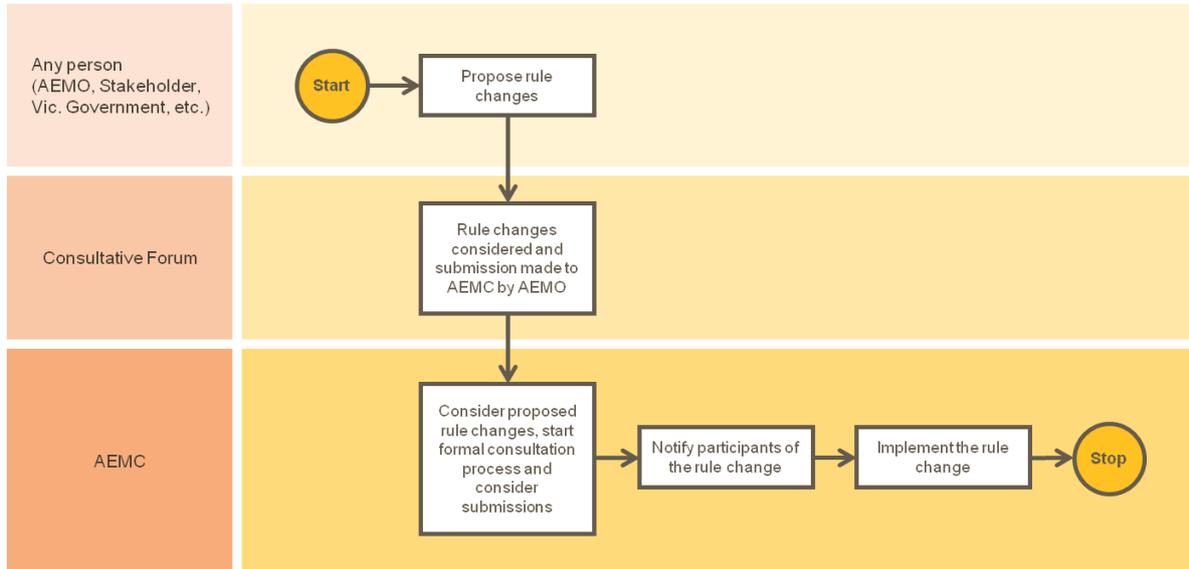
Figure 2-4   The rule change process

3 Participants in the DWGM

This chapter discusses the different types of participants operating in the DWGM, and their rights and obligations. Participants can be directly or indirectly involved in the DWGM. Figure 3-1 summarises the commercial relationships between the different types of participants in the DWGM.

In this chapter:

- Market operator

- Market participants

- Other participants

- Registration
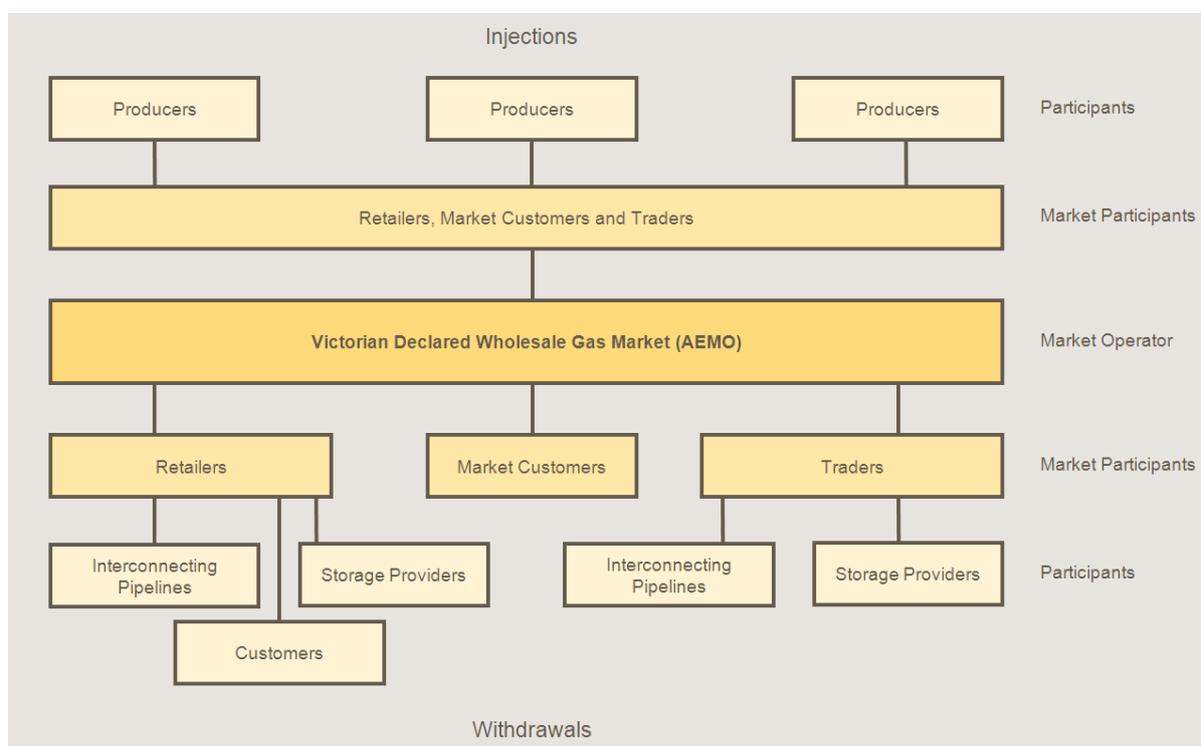
Figure 3-1   Participants in the DWGM

3.1   Market operator

AEMO is the national gas and electricity market operator established by law to undertake its various market and system operation functions. These functions include the management of the wholesale and retail gas market in Victoria and network operation of the DTS.

3.2   Market participants

Those who are entitled to inject gas into or withdraw gas from the DTS are referred to as "market participants" (MPs). There are three types of market participants:

Retailers

Retailers purchase gas from gas producers, bid this gas into the DWGM, and then sell it to end-use customers. Imbalances are settled through the DWGM. Retailers must be licensed by the Essential Services Commission. Because retailers trade gas in the DWGM, they are market participants.

Market customers

A small number of large customers have elected to participate directly in the DWGM. Market customers are responsible for sourcing their own gas from the DWGM and making commercial arrangements for transportation of the gas through the transmission and distribution networks to their premises. Market customers are market participants.

Traders

Traders are MPs who buy gas from and sell gas to other market participants or gas producers. Traders can also trade gas interstate through the interconnecting pipelines. Traders do not have nor require a retailer licence. In some markets, traders are also referred to as shippers. Traders are market participants.

3.3   Other participants

Declared Transmission System Service Provider

APA-GasNet is the Declared Transmission System Service Provider (DTSSP) who owns and maintains the DTS gas transmission system and related facilities used to transport gas from injection points to withdrawal points.

Producers

A producer is a participant who processes gas from fields and injects it into the DTS. A producer can also be a market participant if it bids gas directly into the DWGM.

Storage providers

A storage provider operates a facility that stores natural gas for injection into the DTS (and which might also have been transported through the DTS). The stored gas, which is typically owned by a retailer or trader, is usually injected into the DTS during periods of peak demand. A storage provider can also be a market participant if it bids gas directly into the DWGM.

Interconnected transmission pipeline service providers

Interconnected transmission pipeline service providers (ITPSP) own, maintain and operate other transmission pipelines that connect to the DTS. ITPSPs interface with the DWGM through the connecting flange of their network with the DTS. They enter into connection operating agreements with AEMO.

Distributors

Distributors (distribution network businesses) own and operate the lower pressure distribution networks. Distributors transport gas withdrawn from a transmission system through their distribution pipelines to the end-use customers.

Customers

Customers purchase gas from their retailer of choice. Customers are distribution customers if they are connected to a distribution system network. Alternatively, they are transmission customers if they are connected directly to the transmission system. Customers are further assigned by their level of gas demand to tariff classes as:

- Tariff D if the consumption is more than 10 TJ per year or the maximum quantity is more than 10 GJ per hour.

- Tariff V applies to residential, small to medium-sized commercial and industrial sites.

3.4   Registration

To participate in the DWGM, interested parties must register with AEMO. Registration forms are available on the AEMO website. Interested parties are encouraged to contact AEMO prior to submitting an application so that any areas of uncertainty can be discussed and clarified in advance.

In addition to the general requirements listed in the application, different requirements apply to different categories of participants. Table 3.1 lists some specific requirements for MPs and the organisations that MPs need to contact to obtain approvals for those requirements.

AEMO will contact the applicant within five business days of receiving the application if further information is required. If AEMO does not receive the requested information within a further 15 business days, the application will be considered to be withdrawn.

If the application is successful, AEMO will advise the applicant of the outcome within 15 business days of receiving the application or, if further information is requested, within 15 days of receipt of the information.

Table 3.1   Registration requirements for market participants

Requirement	Who does it apply to?	Who to contact for approval?
Prudential	All market participants	
Connection to AEMO IT systems	All market participants	AEMO
Approved retail licence	Retailers	AER
Approved gas safety case	Retailers	Energy Safe Victoria
Agreed Transmission Use of System Agreement	All market participants	APA-GasNet
Agreed Distribution Use of System Agreement	Retailers, distribution market customers	Distributors

For further information about how to register as a participant in the DWGM, visit the AEMO website or contact the Information & Support Hub at supporthub@aemo.com.au.

4 Trading Gas in the DWGM

This chapter provides an overview of the processes by which market participants trade gas in the DWGM. Refer to Chapter 5 for descriptions of the systems AEMO uses to manage these processes.

In this chapter:

- Managing imbalances

- Gas market processes

4.1 Managing imbalances

MPs, in particular retailers, usually enter into long-term gas supply contracts with producers and must manage their exposure to the financial risks in the DWGM. However, MPs must trade gas with each other or buy and sell linepack gas to manage imbalances on each gas day.

The diagrams in Figure 4-1 show some possible scenarios of gas traded by MPs. These examples assume there are only two MPs (A and B) involved. Colours are used to indicate the gas bought or sold between each MP (red and yellow) and trading system linepack imbalances (blue). The lower part of each diagram also indicates the source of the purchased gas by colour.
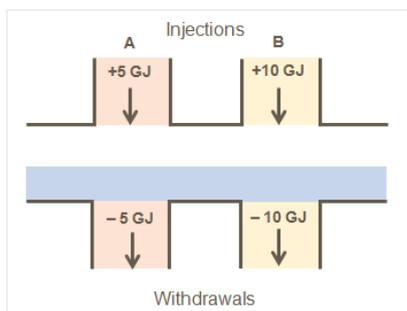
Scenario 1: No gas traded

Market participants A and B withdraw the same quantities of gas as they each inject (5 TJ and 10 TJ, respectively) during a trading period. Both are in balance and there is no change in linepack.

No gas is traded on the DWGM.
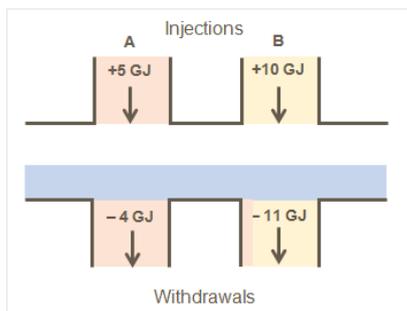
Scenario 2: 1 GJ of gas traded, no change in linepack

A injects 5 GJ as scheduled and withdraws 4 GJ; B injects 10 GJ and withdraws 11 GJ during a trading period. Total injections balance total withdrawals so there is no change in system linepack. A has sold 1 GJ to B at the market price, which is set by A's marginal price bid for the last GJ it injected.
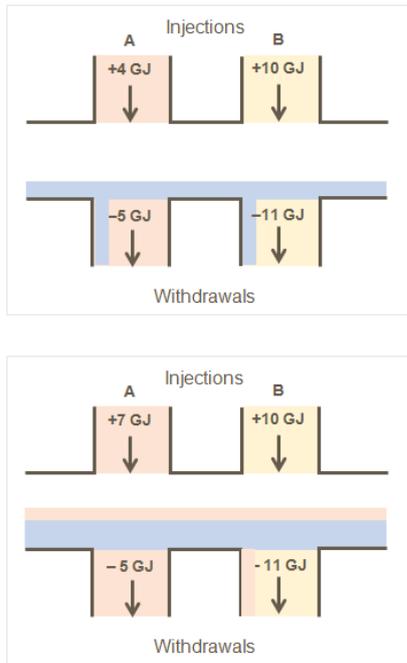
Scenario 3: More gas withdrawn than injected, reduced linepack

A and B both withdraw 1 GJ more gas than they each inject resulting in 2 GJ reduction in system linepack. A and B have each bought 1 GJ from system linepack gas at the market price to meet the gas demands of each of their customer loads.

Scenario 4: One MP over-injected, increased linepack

A injects 7 GJ and withdraws 5 GJ. B injects 10 GJ and withdraws 11 GJ. A sells 1 GJ to B and sells 1 GJ into system linepack at the market price.

Figure 4-1   Gas trading examples

4.2   Gas market processes

There are five main processes by which gas is traded in the DWGM. Figure 4-2 provides an overview of these processes and how they are related by their inputs and outputs.
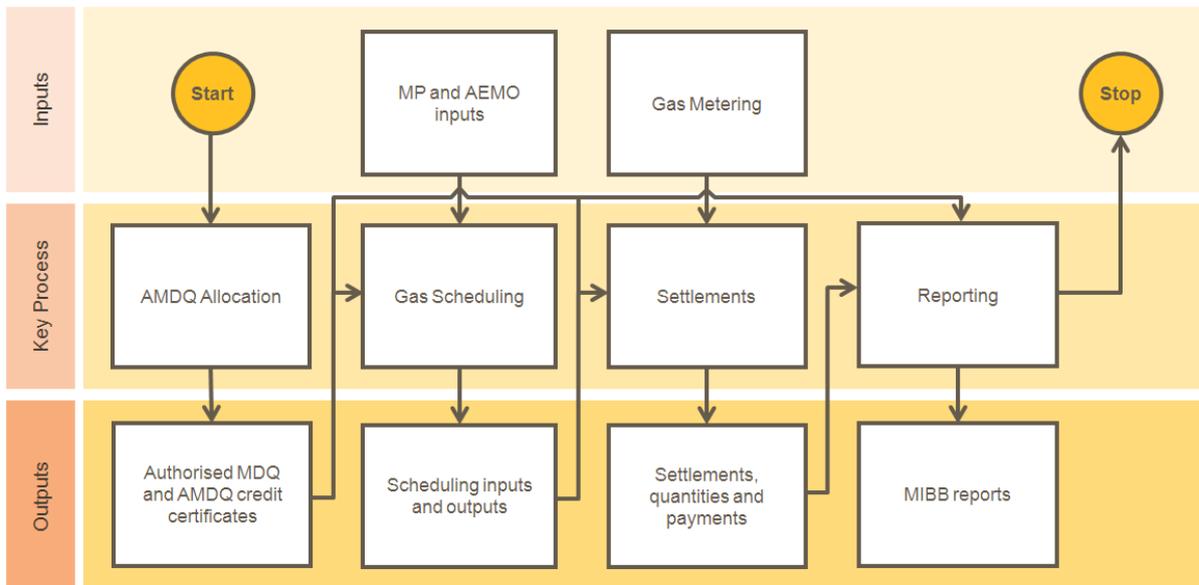
Figure 4-2   Overview of the key processes in the DWGM

AMDQ allocation

Transportation rights (authorised MDQ and AMDQ credit certificates—see Section 2.5 for description) are allocated by AEMO to MPs. These AMDQ are inputs to the gas scheduling, settlements and reporting processes. Refer to Chapter 6 for details of the AMDQ allocation process.

Gas scheduling

Gas is scheduled by AEMO using demand forecasts, transportation rights, and the available injection and withdrawal bids. This determines the gas market price and the schedules for each MP. These schedules define the quantities of gas that each MP will inject at each injection point and the quantities they can withdraw from the DTS by any controllable loads during the gas day. Refer to Chapter 7 for details of the gas scheduling process.

Gas metering

The metering process records the gas quantities that flow through the DTS over a gas day. This provides the necessary inputs for AEMO to calculate who is paid for the gas they supplied or pays for the gas they withdrew on each gas day. The process includes metering installation, meter registration and metering database maintenance. Refer to Chapter 8 for details of the gas metering process.

Settlement

AEMO uses the inputs from the other processes to calculate payments to and from MPs for the net gas they flowed on a gas day. Refer to Chapter 9 for details of the settlement process.

Reporting

AEMO publishes information in the Market Information Bulletin Board (MIBB). The MIBB is the interface through which AEMO communicates with MPs. This provides participants with essential market data and market notices. General market information is also made available to the public through the MIBB. Refer to Section 5.6 for a description of the information available on the MIBB.

5 The Gas Market System

The Gas Market System (GMS) is the software and data by which AEMO operates the DWGM and by which participants participate in the DWGM. It consists of seven inter-related applications. Figure 5-1 shows the applications that make up the GMS and how they are linked. These applications are described in the sections that follow. Additional information about the information flow can be found in to Appendix C.

In this chapter:

- Transportation and Market Manager

- WebExchanger

- SCADA

- Market Clearing Engine

- Metering and Settlements System

- Market Information Bulletin Board

- Demand Forecast System
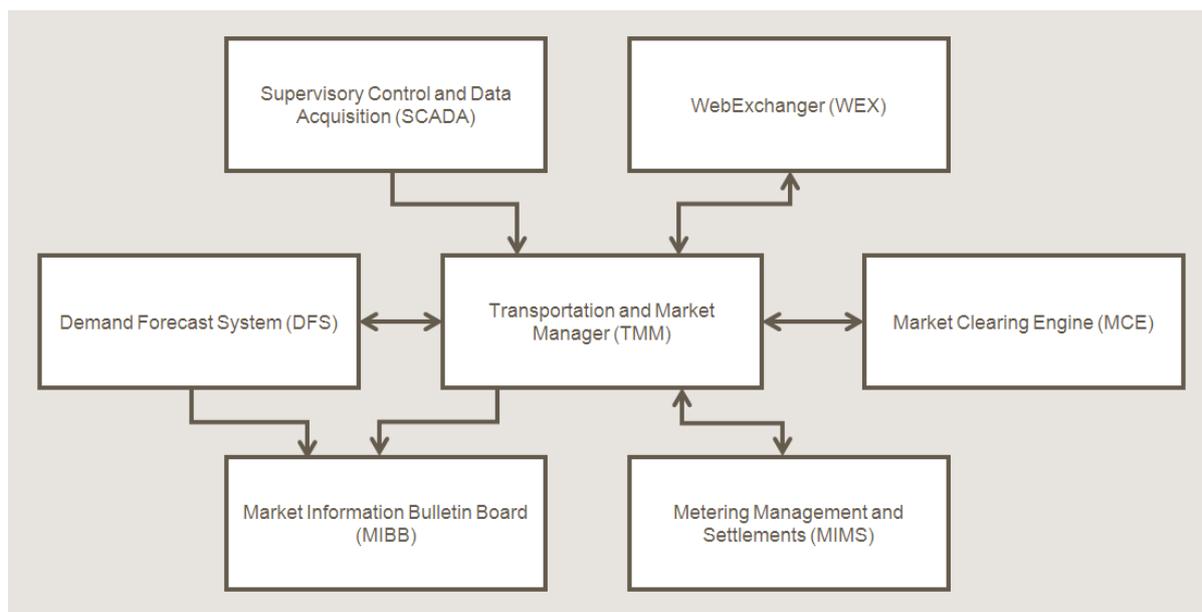
Figure 5-1   Overview of the Gas Market System (GMS)

5.1   Transportation and Market Manager

The Transportation and Market Manager (TMM) is the central application software, which performs the following functions:

- Stores market information submitted by MPs via the WebExchanger—see Section 5.2.

- Stores and maintains MCE reference and operational data from the SCADA system—see section 5.3.

- Organises gas scheduling information required for initiating runs of the Market Clearing Engine (MCE)—see section 5.4.

- Processes the outputs from the MCE.

- Stores and processes demand forecasts provided by MPs before they are forwarded to the Demand Forecasting System (DFS) for further processing—see section 5.7.

- Organises market data for publication in the Market Information Bulletin Board (MIBB)—see section 5.6.

5.2   WebExchanger

The WebExchanger is the web application by which MPs submit bid data and other required market information to AEMO. The WebExchanger is an integral part of the MIBB. Refer to the *WebExchanger User Guide* [29] for details.

5.3   SCADA

The SCADA (supervisory control and data acquisition) system stores DTS operational data such as nodal pressures, injection pressures, LNG stock level, heating values, and system linepack data.

5.4   Market Clearing Engine

The Market Clearing Engine (MCE) is the linear programming optimisation program that produces the operating and pricing schedules for the gas market based on the schedule input information passed from the TMM. The MCE uses a simplified model of the pipeline system.

5.5 Metering and Settlements System

The Metering and Settlements System (MMS) has two separate components:

Metering system

- Manages the collection and storage of metered energy values from metering data agents (MDA) and allocation agents, which are used in the settlements process.

- Processes and stores the adjusted metered energy values to account for gas losses in the DTS. AEMO (or the appropriate MDAs) apply the appropriate unaccounted-for-gas (UAFG) rates at the system withdrawal points.

Settlement system

- Manages the production of financial settlement statements and supporting data for MPs in the DWGM.

- Determines the energy traded by participants using energy values extracted from the metering system and calculates payments to and from MPs (using inputs from other systems—market prices, for example) for each billing period.

- Performs prudential monitoring and the calculation of ancillary and uplift payments.

5.6 Market Information Bulletin Board

The Market Information Bulletin Board (MIBB) is the interface through which AEMO communicates with participants. The MIBB provides transaction interfaces with external MPs, reports market information, and publishes system-wide notices to MPs and the general public.

Participants must comply with the procedures set out by AEMO for electronic communications between AEMO and participants. Refer to *Electronic Communication Procedures* [28] for details.

Access to these reports will depend on a user's security privileges, which fall into three general classes:

- **Public.** Information is available to everybody, including members of the general public. There is no security control over this information.

- **All participants.** Information is available to all organisations participating in the gas market.

- **Participant confidential.** Information is available only to an individual or a restricted group of participants.

The generation and publishing of a report can be initiated in three ways:

- Daily at a predetermined time.

- Triggered by an event.

- Forced by the administrator.

Details of the market reports can be found in the *MIBB Report Participant Guide* [30]. The published details can include (but are not limited to) purpose, format, contents, type of access, frequency of reporting and specification of the data fields.

5.7 Demand Forecast System

The Demand Forecast System (DFS) prepares forecasts based on:

- Forecasts by MPs of their loads, including individual forecasts for very large customers.

- Weather forecasts from the Bureau of Meteorology and input data from the TMM on historical load profiles and levels.

The DFS demand forecasts and weather data (actual and forecast) are published on the MIBB.

6 Transportation Rights

Transportation rights include both authorised AMDQ and AMDQ credit certificates, which are collectively known as AMDQ (see Section 2.5 for a general description of AMDQ). This chapter describes AEMO's process for allocating AMDQ, outlines the process by which MPs obtain them, and explains the benefits they provide to their holders.

In this chapter:

- Authorised MDQ

- AMDQ credits

- Obtaining AMDQ

- Benefits of AMDQ

- Public register of spare capacity

Refer to the *National Gas Rules* Part 19 Division 4 Subdivision 3 for more details.

6.1   Authorised MDQ

Authorised MDQ is a transportation right, which provides a hedge against congestion uplift, for MPs withdrawing gas from the DTS that has been injected at Longford. Individual Tariff D customer sites with authorised MDQ also get "in principle" preferential treatment in the event of load shedding resulting from a transmission constraint.

The initial allocation of authorised MDQ occurred in 1998 when Longford was the only source of gas supply for the DTS. The total authorised MDQ was set equal to the peak capacity of the system from Longford of 990 TJ/d. The authorised MDQ was allocated to the following existing and committed new loads (at that time):

- Tariff D large customer sites, typically with demand exceeding 10 TJ per year. The authorised MDQ allocated to each site was set equal to the contract MDQ with revisions approved by an independent panel.

- The Interconnect, Wimmera pipeline, and Murray Valley towns.

- The balance of the 990 TJ was assigned as a block to Tariff V customers—that is, all residential and small-to-medium sized commercial and industrials.

AEMO suballocates the Tariff V authorised MDQ block amongst the retailers in proportion to their calculated share of the Tariff V load on winter high-demand days. The proportions are adjusted at the end of each gas day for net customer transfers and customer growth during the gas day.

Refer to the *Uplift Payment Procedures* [22] for more information on allocation of Tariff V authorised AMDQ to market participants.

Under particular circumstances, MPs holding authorised MDQ can change tariffs (see Section 6.1.1) and transfer them to other MPs (see Section 6.1.2).

Figure Figure 6-1 outlines the process for the initial allocation and reallocation of authorised MDQ.
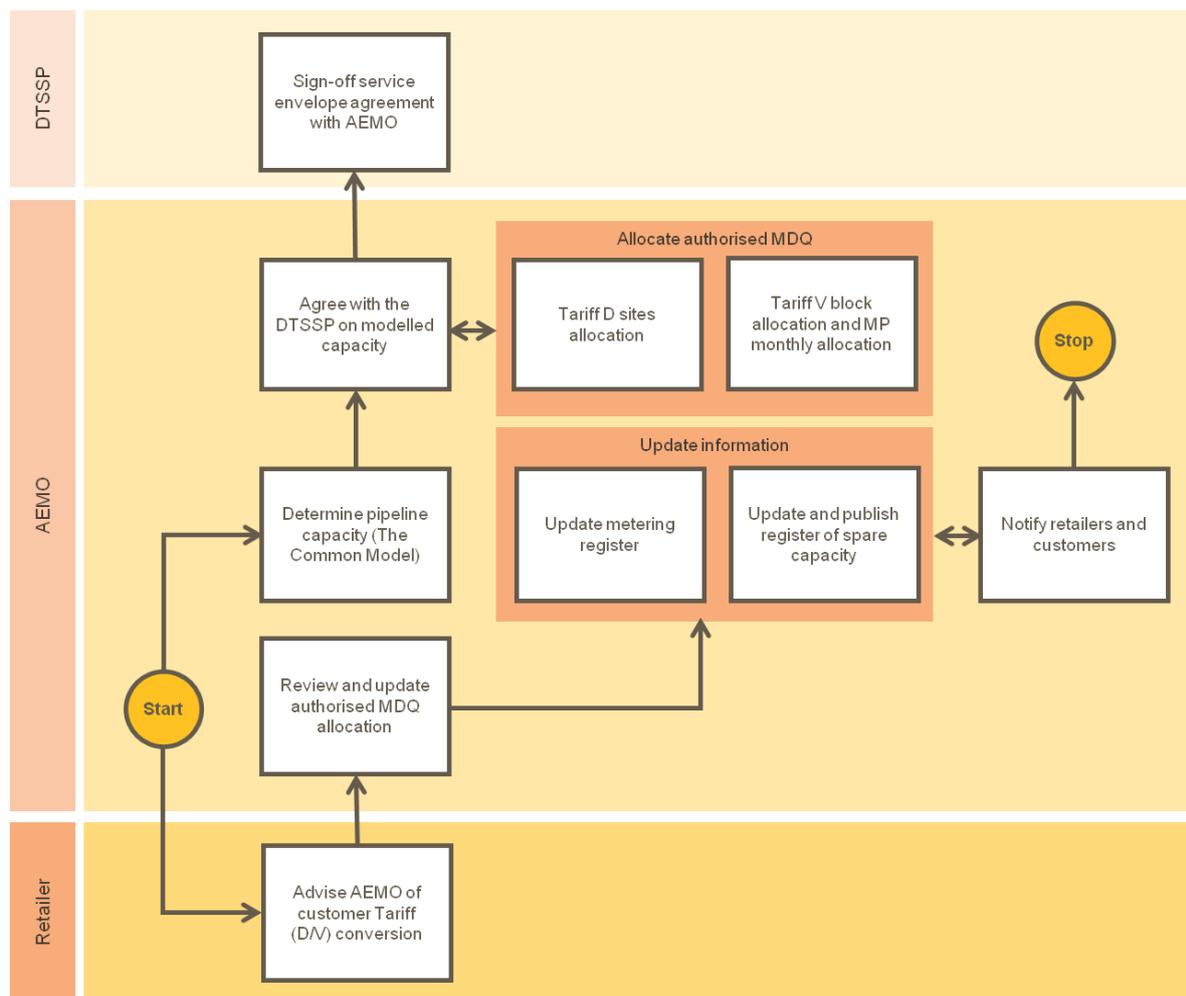
Figure 6-1   Allocation and reallocation of authorised MDQ

See Appendix D for a detailed diagrammatic representation of authorised MDQ.

6.1.1   Changing tariffs

Customers can change from Tariff D to Tariff V (or vice versa) subsequent to the initial authorised MDQ allocations. The responsible retailer is required to advise AEMO of this tariff change so that the authorised MDQ can be updated accordingly. When changing tariffs, note that:

- If a Tariff D site converts to Tariff V, any authorised MDQ allocated to that site is relinquished and will be added to the Tariff V block.

- If a Tariff V site that was part of the initial authorised MDQ allocations in 1998 converts to Tariff D, it is allocated a quantity of authorised MDQ based on its estimated daily loads on winter peak days in 1998 (new Tariff V sites established after 1998 cannot be allocated Tariff D authorised MDQ). This is subject to such data being made available to AEMO—bimonthly billing data can be used as the basis of estimates, for example.

From time to time, AEMO conducts auctions of accrued relinquished or identified spare authorised MDQ.

6.1.2   Transferring authorised MDQ

Authorised MDQ can be transferred:

- Between Tariff D customer sites

- From a Tariff D customer site to the reference hub

- From the reference hub to a Tariff D customer site

- Between parties at the reference hub

To ensure that authorised MDQ continues to align with physical capacity, the transfers of authorised MDQ take account of the following factors:

- **Diversity factor.** Each Tariff D site has had an authorised MDQ diversity factor assigned to it based on the actual gas usage, which is reviewed periodically or as required. The diversified AMDQ is equal to the product of the (certified) authorised MDQ and the diversity factor.

- **Location factor.** In transfers where one or more of the sites is upstream of Pakenham, a location factor is applied to the transferred amount.

Note. The reference hub is a notional site within the gas transmission system established for the purpose of valuing authorised MDQ and AMDQ credit certificates—when an MP does not nominate its entire AMDQ to actual sites, it has to nominate its residual AMDQ somewhere. The diversity factor and location factor at the reference hub are both equal to 1.

6.2   AMDQ credits

The capacity of the DTS has increased as a result of gas system developments and augmentations such as The Interconnect, the South West Pipeline, the Western Transmission System, the Brooklyn Lara Loop, and the BassGas project. This additional capacity is allocated as AMDQ credit certificates.

Referring to Figure 6-2, the process for allocating AMDQ credit certificates involves the following steps:

- AEMO and the DTSSP agree on the increased pipeline capacity resulting from the extension or expansion project and update the SEA accordingly.

- MPs apply to the DTSSP for transportation rights (see Section 6.3).

- AEMO allocates the AMDQ credit certificates to MPs for quantities and periods as directed by the DTSSP.

- Revenues received by the DTSSP for AMDQ credit certificates are deducted from their regulated revenues.

MPs with AMDQ credit certificates must advise AEMO whether the allocated AMDQ credit certificates are to be nominated to sites or the reference hub. The nominated AMDQ credit certificates are called AMDQ credits. Holders of AMDQ credits are entitled to the benefits discussed in Section 6.4.

An MP with excess AMDQ credit certificates can trade capacity to another party. Transfers of AMDQ credit certificates are currently limited to transfers between parties at the reference hub.
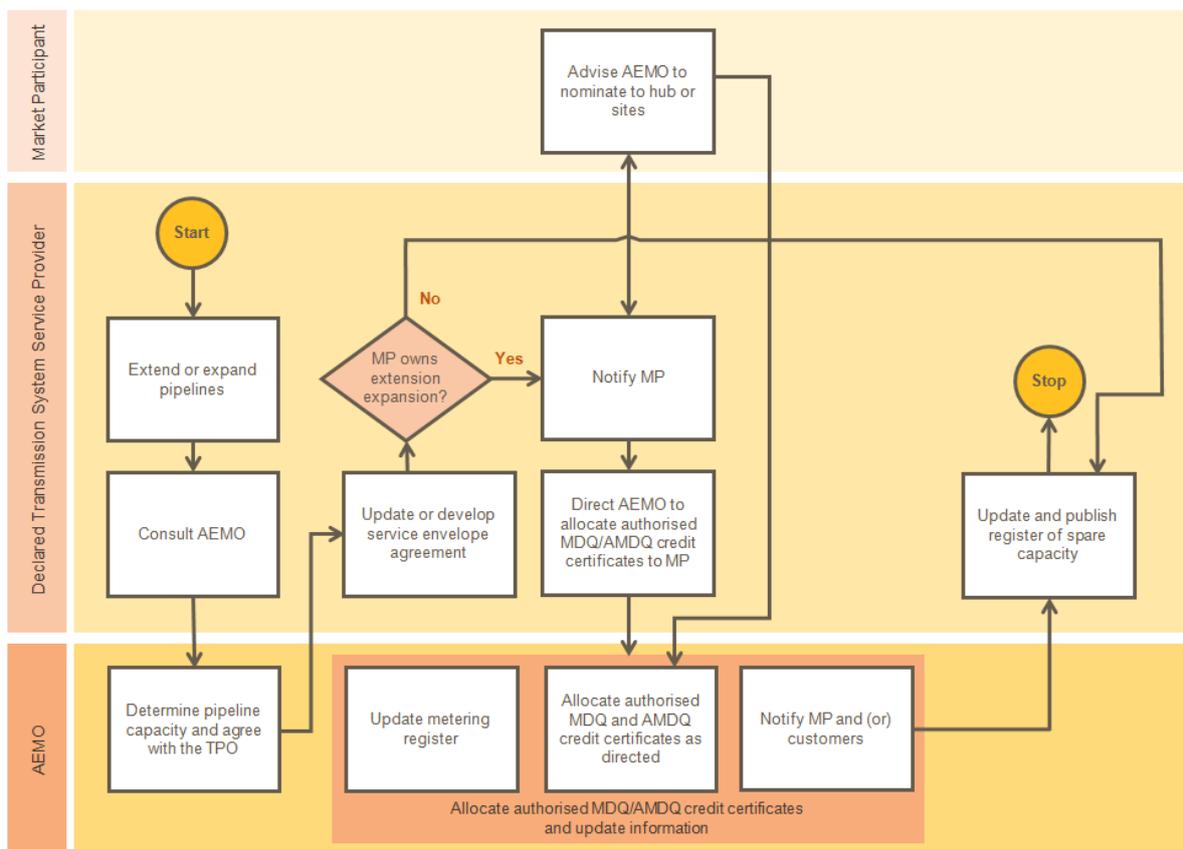
Figure 6-2   Allocation of AMDQ credit certificates

See Appendix D for a detailed diagrammatic representation of allocation of AMDQ credit certificates.

6.3   Obtaining AMDQ

There are many ways that MPs can acquire AMDQ (authorised MDQ and AMDQ credit certificates). They can:

- Negotiate with holders of authorised MDQ to transfer an agreed quantity from one site to another or to the reference hub.

- Negotiate with holders of AMDQ credit certificates to transfer an agreed quantity at the reference hub.

- Apply to the DTSSP for AMDQ credit certificates when they expand the capacity of the DTS.

- Negotiate with the DTSSP to acquire existing AMDQ credit certificates when they expire.

- Contract with the DTSSP to privately expand the DTS capacity.

- Bid for spare authorised MDQ at auctions conducted by AEMO.

For more details about obtaining and transferring authorised MDQ and AMDQ credit certificates refer to references [13], [14], [15], and [17] in Appendix B.

6.4   Benefits of AMDQ

Holders of authorised MDQ and AMDQ credits have the following benefits:

- **Curtailment rights.** In the event of transmission constraints, unauthorised customers are disconnected from the system ahead of authorised customers.

- **Priority in scheduled injections.** When there are equal-priced injection bids, those associated with authorised MDQ or AMDQ credits are scheduled first—see Section 7.5.5 for more information.

- **Reduced uplift payments.** MPs can use part or all of their authorised MDQ or AMDQ credits as uplift hedges—see Chapter 14 for more information.

6.5   Public register of spare capacity

In accordance with the *National Gas Rules* Part 11, Rule 111, APA-GasNet maintains and publishes a public register of spare capacity on the APA Group website (www.apa.com.au). This register reports capacity of pipelines and the amount, if any, of unallocated authorised MDQ or AMDQ credit certificates.

7 Gas Scheduling

AEMO produces operating schedules a number of times each gas day for each MP, which specify the market price and each MP's injection quantities and controllable withdrawals. The market clearing algorithm used in optimising each operating schedule minimises the cost of supplying the forecast gas demand within the pipeline system security limits.

In this chapter:

- Overview of the gas scheduling process

- Normal operating conditions

- Abnormal operating conditions

- Gas schedules

- Market participant inputs

- AEMO's inputs

- Scheduling outputs

For more information about the gas scheduling process, refer to the *Gas Scheduling Procedures* [6].

7.1   Overview of the gas scheduling process

Figure 7-1 depicts the key steps in the gas scheduling process, which link the data inputs from MPs and AEMO to the scheduling outputs published in the MIBB. A different process is followed depending on whether the system is operating under normal (see Section 7.2) or abnormal conditions (see Section 7.3).

7.2   Normal operating conditions

Under normal operating conditions, AEMO performs the following tasks each time it prepares, runs, and issues a schedule:

- AEMO collates the input data from MPs, including forecast demand and injection and withdrawal bids (see Section 7.5), prepares its own input data and demand forecasts (see Section 7.6), and, if required, overrides demand forecasts from MPs (see Section 15.2).

- AEMO runs the Market Clearing Engine (MCE) based on the input data to produce the optimal schedules (see Section 7.4).

- AEMO assesses the schedules produced by the MCE.

- AEMO issues pricing and operating schedules (see Section 7.7) if the MCE results are accepted or reassesses the input data and repeats the process.

This occurs nine or more times for each and every gas day.
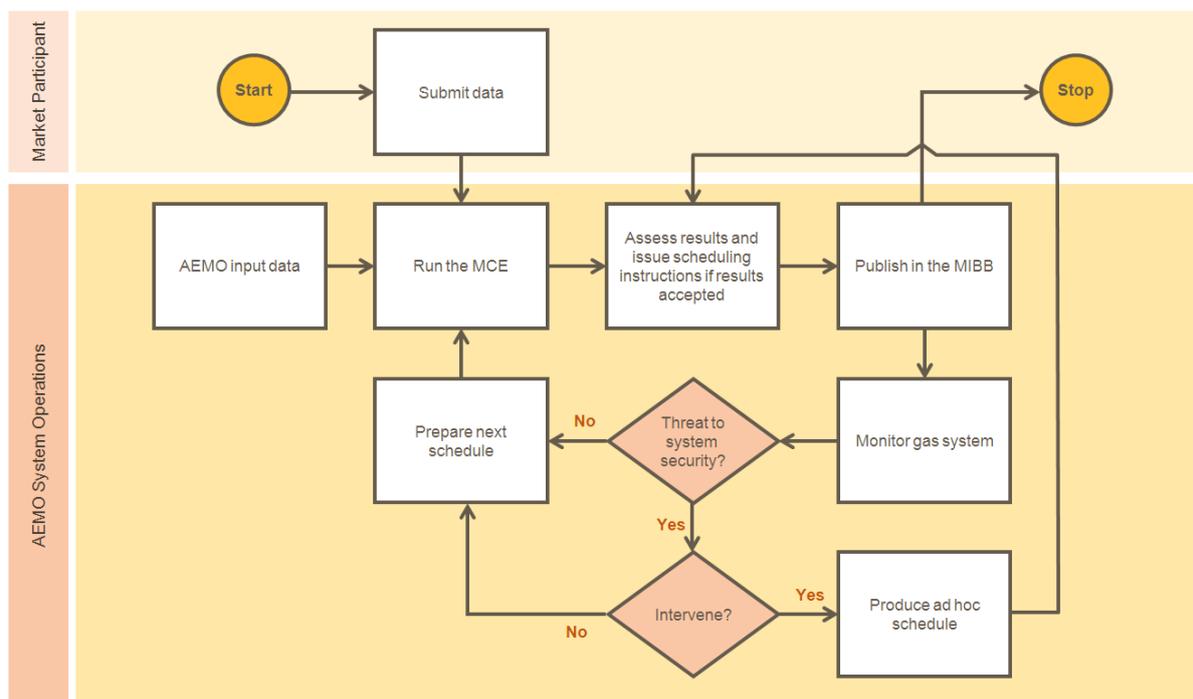
Figure 7-1   The gas scheduling process

7.3   Abnormal operating conditions

The information provided in this section is intended only as an overview. In the case of any abnormal operating condition, participants must familiarise themselves with the relevant rules and procedures. In particular, the *Gas Scheduling Procedures* [6], *System Security Procedures* [7], *Administered Pricing Procedures* [18], *Gas Emergency Protocol* [26], *Gas Quality Guidelines* [31], and the relevant sections of the *National Gas Rules* [44].

7.3.1   Threats to system security

Monitoring system security is an integral part of the process that determines whether and when AEMO needs to take actions in case of system security threats. Threats to system security can be caused by:

- Unplanned producer or transmission plant outages

- Gas demand exceeding transmission system capacity

- Gas demand exceeding available supply

- Transmission pipeline gas escapes or damage

- Ongoing injections of off-specification gas

In the event of a system security threat, AEMO will:

- Notify participants of the potential or existing system threat with a system-wide notice published in the MIBB.

- If time is available, seek advice from participants and MPs on corrective actions that will mitigate the risk or threat—for example, AEMO might request MPs to change their market bids or offer additional gas.

- If necessary, intervene in the market by issuing an ad hoc operating schedule.

- In the case of persistent off-specification gas, take steps in accordance with the gas quality guidelines to mitigate or remove the threat—for example, curtail the supply of the substandard gas and schedule additional gas from alternative sources.

- Notify participants and MPs when the threat is removed and conditions return to normal operating conditions.

- Report the event to the Australian Energy Regulator (AER).

AEMO can, if it reasonably considers that the actions available to it under the Gas Industry Act 2001 are not adequate to alleviate the threat, seek the intervention of the Victorian Government. Intervention can include but is not limited to:

- Directing the curtailment of customers.

- Injecting gas from AEMO's LNG reserve.

- Directing the injection of non-firm gas.

For more details about curtailment of customers see the *Gas Load Curtailment and Gas Rationing and Recovery Guidelines* [27] and *National Gas Rules* Part 19, Division 5 "Intervention and Market Suspension" [44]

7.3.2   System force majeure events and market suspension

A system force majeure event is one of the four cases under which AEMO can suspend the market under NGR 347(1).

A system force majeure event is an event that is likely to materially affect the operation of the market or materially threaten system security and that has resulted in a reduction in part or all of the normal capacity of either the DTS or a production facility or a storage facility.

If a system force majeure event occurs, AEMO must notify participants without delay and declare an administered price period.

7.3.3   Administered price period

An administered price period will be invoked if one or more of the following events occur:

- A system force majeure event is declared (see Section 7.3.2).

- The market has been suspended.

- A market price or pricing schedule is unable to be published by the required time.

- The cumulative price threshold has been exceeded (see Section 7.3.4).

AEMO will, as soon as practical, notify all participants via the MIBB of:

- When one or more of the above events occurs.

- When an administered price period commences.

- When the administered price period is revoked and when it terminates.

During an administered price period, AEMO administers the market price, pricing schedules, and ancillary payments for the scheduling horizons affected in accordance with the procedures prescribed by the NGR. The market price is capped at the administered price cap, which is currently set at 40 $/GJ. The administered price cap will be reviewed as and when required.

The administered price period is revoked when AEMO determines that all of the following conditions are met:

- The event that caused the administered price period no longer exists.

- Any further distortion of market pricing is unlikely.

- No other condition for an administered price period is applicable.

7.3.4   Cumulative price threshold

Sustained high prices can trigger an administered price period. The cumulative price is the accumulation of the marginal clearing price (the highest priced bid that is scheduled) over the previous 34 scheduling intervals and the current scheduling interval. The cumulative price threshold is currently set at $3,700.

7.4   Gas schedules

Referring to Figure 7-2, on each gas day, AEMO prepares and issues at least nine schedules:

- Five standard schedules for the current gas day (d) at four-hour intervals at 6 AM,10 AM, 2 PM, 6 PM, and 10 PM—shown in red.

- Three gas schedules for the next gas day (d+1) at 8 AM, 4 PM, and 12 AM midnight—shown in blue.

- One schedule for the gas day after the next day (d+2) at 12 PM midday–shown in gold.

Ad hoc schedules, between the standard schedules on the current gas day, can also be issued but only if there are imminent threats to system security that require urgent action.

Scheduling inputs due	Scheduling horizon			Gas day	Scheduling intervals					Schedule issued
					1	2	3	4	5	
					6 AM to 10 AM	10 AM to 2 PM	2 PM to 6 PM	6 PM to 10 PM	10 PM to 6 AM	
5 AM	6 AM	to	6 AM	current						6 AM
7 AM	6 AM	to	6 AM	d+1						8 AM
9 AM	10 AM	to	6 AM	current						10 AM
11 AM	6 AM	to	6 AM	d+2						12 PM
1 PM	2 PM	to	6 AM	current						2 PM
3 PM	6 AM	to	6 AM	d+1						4 PM
5 PM	6 PM	to	6 AM	current						6 PM
9 PM	10 PM	to	6 AM	current						10 PM
10 PM	6 AM	to	6 AM	d+1						12 AM

All times are EST

Figure 7-2   Gas market scheduling timelines

Note the distinction between the terms "schedule", "scheduling interval", and "scheduling horizon". For example, a current-day schedule issued at 2 PM is for the scheduling horizon 2 PM to 6 AM, which includes three scheduling intervals (2 PM to 6 PM, 6 PM to 10 AM, and 10 AM to 6 AM).

The 6 AM schedule, also known as the beginning-of-day (BOD) schedule, covers the 24-hour scheduling horizon from 6 AM EST. Information used and issued in the BOD schedule is updated in subsequent schedules. The 10 AM, 2 PM, 6 PM, and 10 PM schedules cover the remaining 20, 16, 12, and 8 hours of the current gas day, respectively.

With the exception of the final d+1 schedule, market participants must submit the required scheduling input data (see Section 7.5) at least one hour prior to the schedule start time. The cut-off time for the final d+1 schedule is 10 PM. This allows AEMO to compile and assess the input data, run the MCE, and confirm that the outputs are satisfactory before issuing the schedules. Accordingly, the cut-off times for MP data submissions for the standard schedules are:

• 5 AM, 9 AM, 1 PM, 5 PM, and 9 PM for the current gas day

• 7 AM, 3 PM, and 10 PM for the next gas day (d+1)

• 11 AM for two-days ahead (d+2)

Each schedule comprises an unconstrained pricing schedule that sets the market price and an operating schedule that accounts for constraints.

7.5   Market participant inputs

Each MP submits the following input data, as applicable, for each standard schedule (see Section 7.4) for each gas day:

• Market bids—injection and controllable withdrawal bids—see Section 7.5.1

• Demand forecasts—see Section 7.5.2

- Injection hedge nominations—see Section 7.5.3

- Agency injection hedge nominations—see Section 7.5.4

- AMDQ nominations—see Section 7.5.5.

MPs submit the data via the WebExchanger in the MIBB, available at
http://vicgas.venprod.vencorp.vic.gov.au/.

MPs must obtain accreditation of bid constraints that apply to specific connection points where the MP plans to inject gas to or withdraw gas as controllable withdrawals from the DTS. These constraints reflect physical limits of the facility and an MP's contractual limitations. See Section 7.5.6 for information about bid constraints.

7.5.1   Market Bids

MPs who intend to inject gas or withdraw gas as controllable withdrawals must submit bids via the WebExchanger using the Bid Set input screen. Figure 7-3 shows the WebExchanger input screen for bid data.

Market bids can be submitted by AEMO system operators on behalf of a market participant via TMM. However, this is only a fallback if the WebExchanger fails or the MP cannot access the system.

MPs can specify up to ten price-quantity steps in each bid for each injection and controllable withdrawal point. For injection bids, the specified bid quantity increases with the increasing bid price. For controllable withdrawal bids, the bid quantity increases with the decreasing bid price. Bid prices in dollars per gigajoule ($/GJ) can vary between zero and the market price cap (VOLL), which is currently set at 800 $/GJ.

MPs can revise and resubmit bids for subsequent schedules. However, the revised total bid quantities must not be less than the quantity already scheduled for any previous scheduling intervals on that gas day. Bids must be submitted at least one hour prior to the standard schedule times.

Before a bid is accepted, AEMO validates and assesses the submitted data. The assessment process is intended to minimise the following risks:

- Data integrity—conflicts or inconsistent input data that might affect the proper operation of the MCE.

- Prudential—inadvertent financial exposure of MPs and the market caused by erroneous input data.

The WebExchanger will generate a message to confirm that the MP's bid has been accepted or rejected.
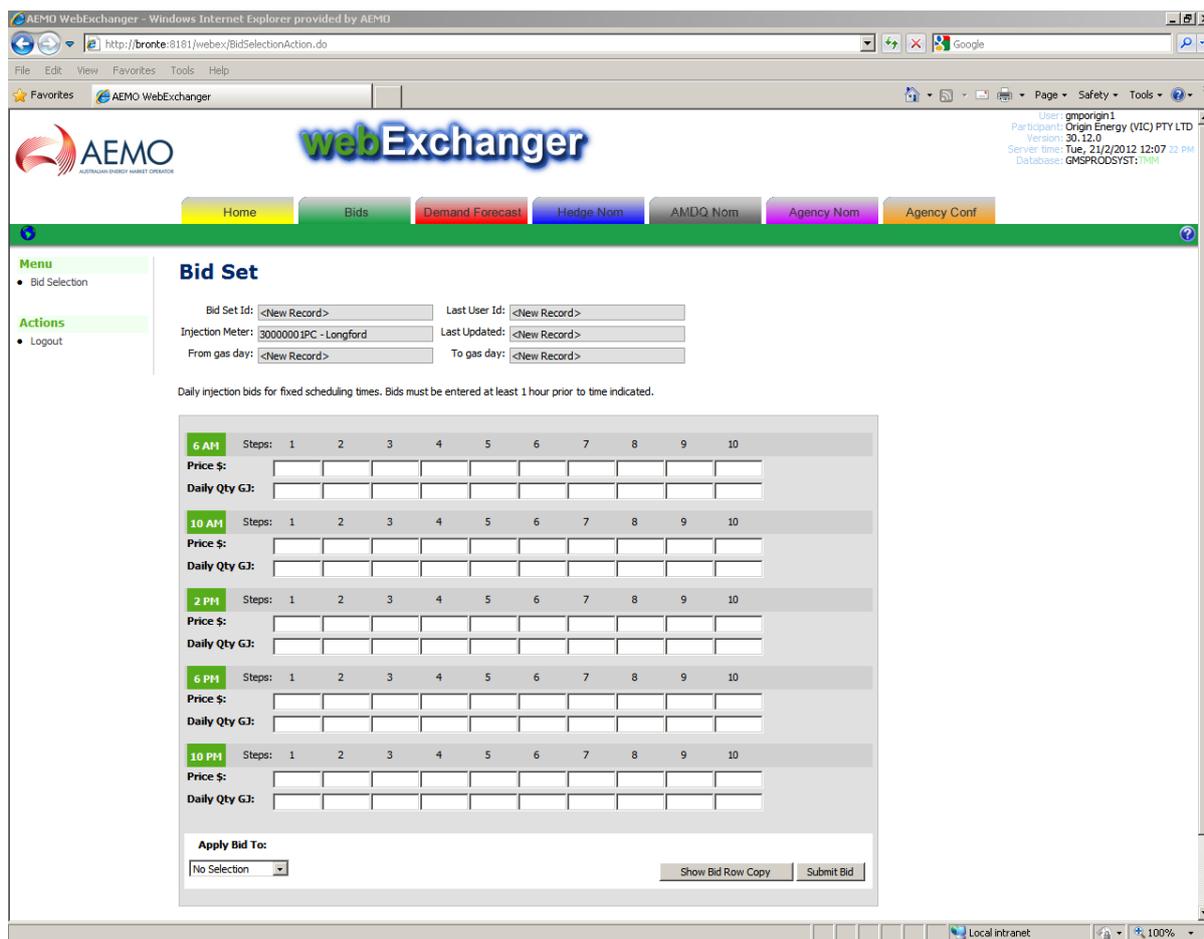
Figure 7-3   WebExchanger Bid Set input screen

7.5.2   Demand forecasts

Unless exempted by AEMO, MPs who supply uncontrollable withdrawals must submit to AEMO hourly demand forecasts for:

- Site-specific demand forecasts for each Tariff D site that has an accredited point-specific maximum daily quantity of 5 TJ/d or more, and, a volatile withdrawal pattern—for example, power generators and large refineries.

- The remaining system-wide uncontrollable withdrawals of their customers.

Figure 7-4 shows the WebExchanger input screen for submitting demand forecasts. MPs can revise their demand forecasts and resubmit them by the relevant cut-off time for each standard schedule.
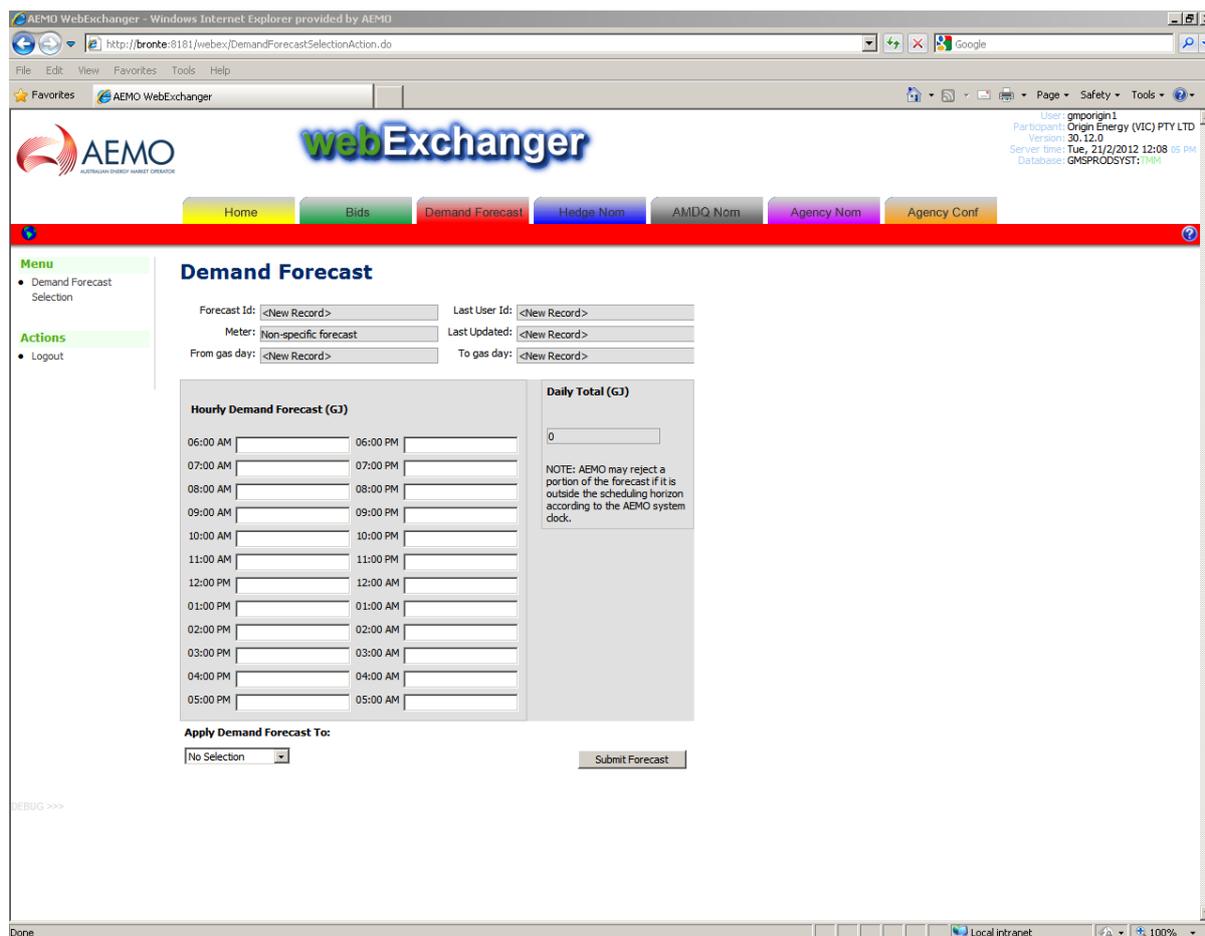
Figure 7-4   WebExchanger Demand Forecast input screen

7.5.3   Injection hedge nominations

An injection hedge nomination is a specified quantity of an MP's scheduled injection from a given close proximity injection point (CPP) that the MP intends to use as an uplift hedge against the potential financial impact due to system congestion. MPs who intend to do so must:

- Hold sufficient AMDQ associated with that CPP.

- Submit the nominated quantities at each CPP (see Figure 7-5) in WebExchanger.

- Nominate a percentage profile for their authorised maximum interval quantity (AMIQ).

An MP can update its AMIQ profile in reschedules within the specified profile limits. If the nominated AMIQ percentage for a given scheduling interval exceeds the prescribed profile limit, it will be rejected. A message is displayed if an error is detected, and the nominating MP can revise and resubmit the data. See Section 14 for more information about calculating AMIQ from authorised MDQ and AMDQ credits and how the AMIQ is used to provide uplift hedges.
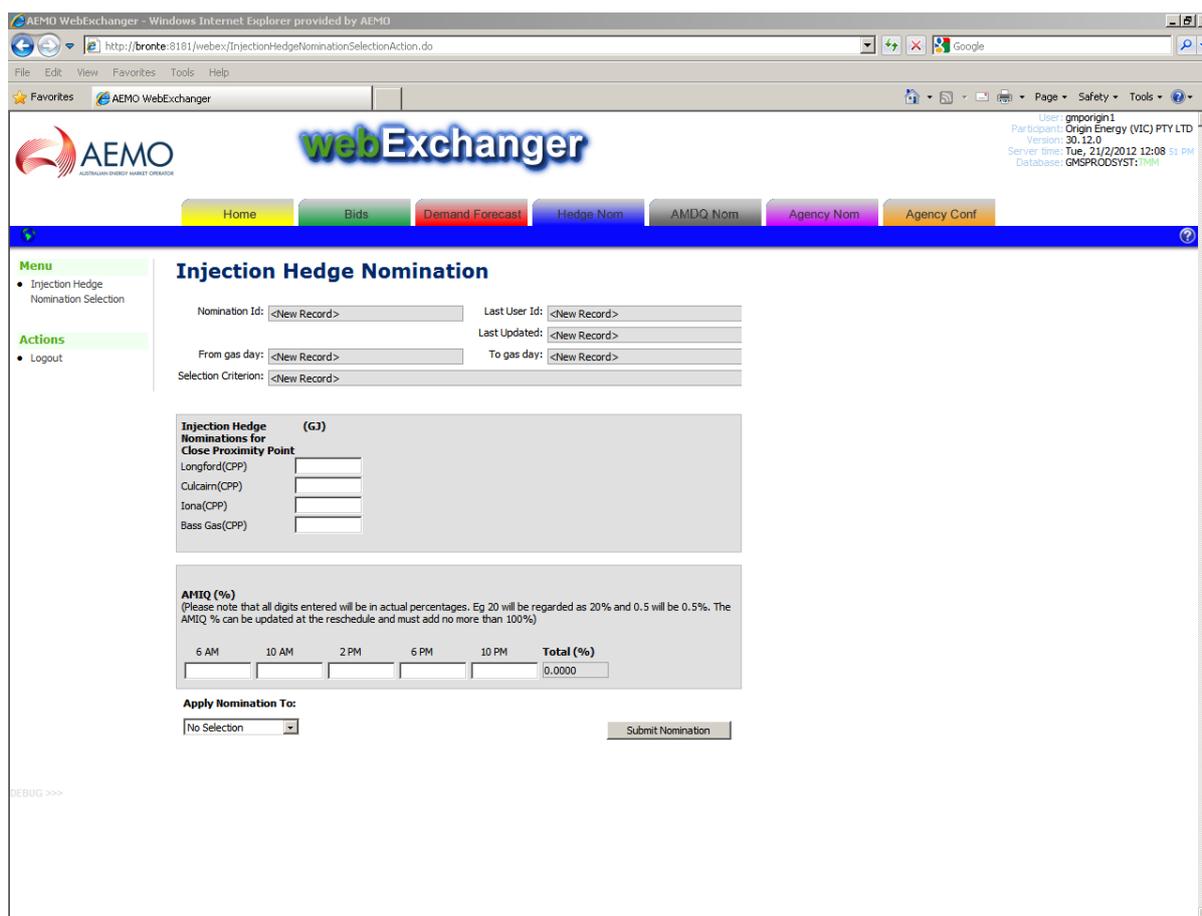
Figure 7-5   WebExchanger Injection Hedge Nomination input screen

7.5.4   Agency injection hedge nomination

An injecting MP (the injector) can allocate a quantity of its scheduled injection to be used as an agency injection hedge nomination (AIHN) for one or multiple recipient MPs at a close proximity injection point for the purpose of generating uplift hedge for the recipient MPs. There can be two or more MPs involved in this process:

The injector submits the following information via WebExchanger (see Figure 7-6):

- The nominated quantity (AIHN) and details of the recipient MPs.

- Whether injections are allocated on a pro rata or preference basis in the event that its scheduled injection is less than the amount required to cover both its own injection hedge nomination and any agency injection hedge nominations.

The recipient MP must confirm acceptance of the AIHN using the agency confirmation function in WebExchanger.

AEMO validates the data submitted by all parties involved and calculates the agency injection hedge. See Chapter 14 for calculation of an MP's total uplift hedge including agency injection hedge generated via AIHN.
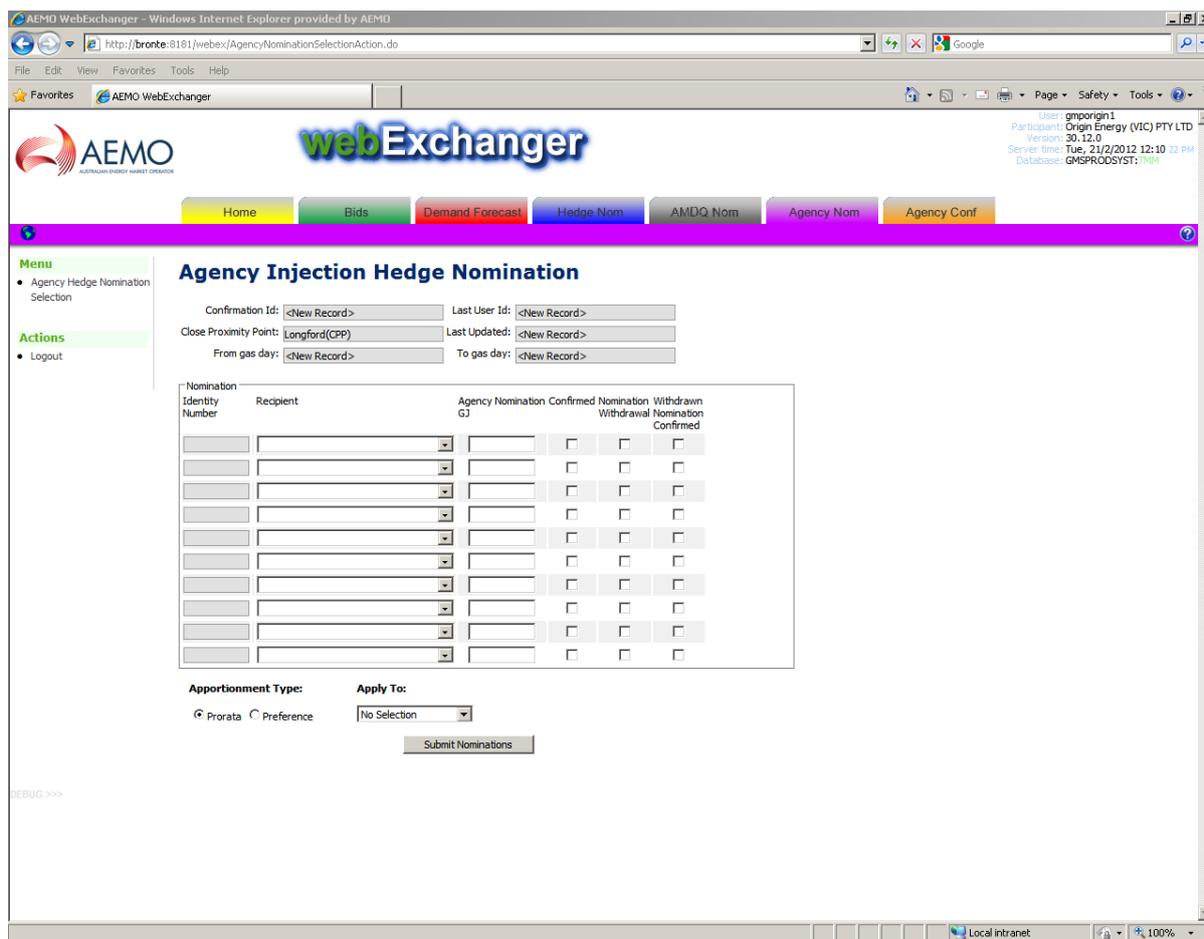
Figure 7-6   *WebExchanger Agency Injection Hedge Nomination input screen*

7.5.5   AMDQ nomination

MPs can nominate their authorised MDQ or AMDQ credits (as a percentage AMDQ% of their total AMDQ) to each individual system injection point (SIP) at the close proximity injection point (CPP) for the purpose of generating injection tie-breaking rights. The latter are used for prioritising tied injection bids with equal bid prices.

The total AMDQ% cannot exceed 100%. Recipients of AIHN can elect to nominate less than 100% of their AMDQ for injection tie-breaking rights. In this case, the amount of the recipient unused AMDQ will be allocated to the injector of AIHN to enhance the injector's total injection tie-breaking rights.

An MP can update its AMDQ nominations in subsequent schedules. However, the revised nominations for each SIP must not be less than the AMDQ needed to support the total injections that have been scheduled for all the previous scheduling intervals at that SIP.

For more details, refer to Appendix D and *Injection Tie-Breaking Right Functional Design* [12].
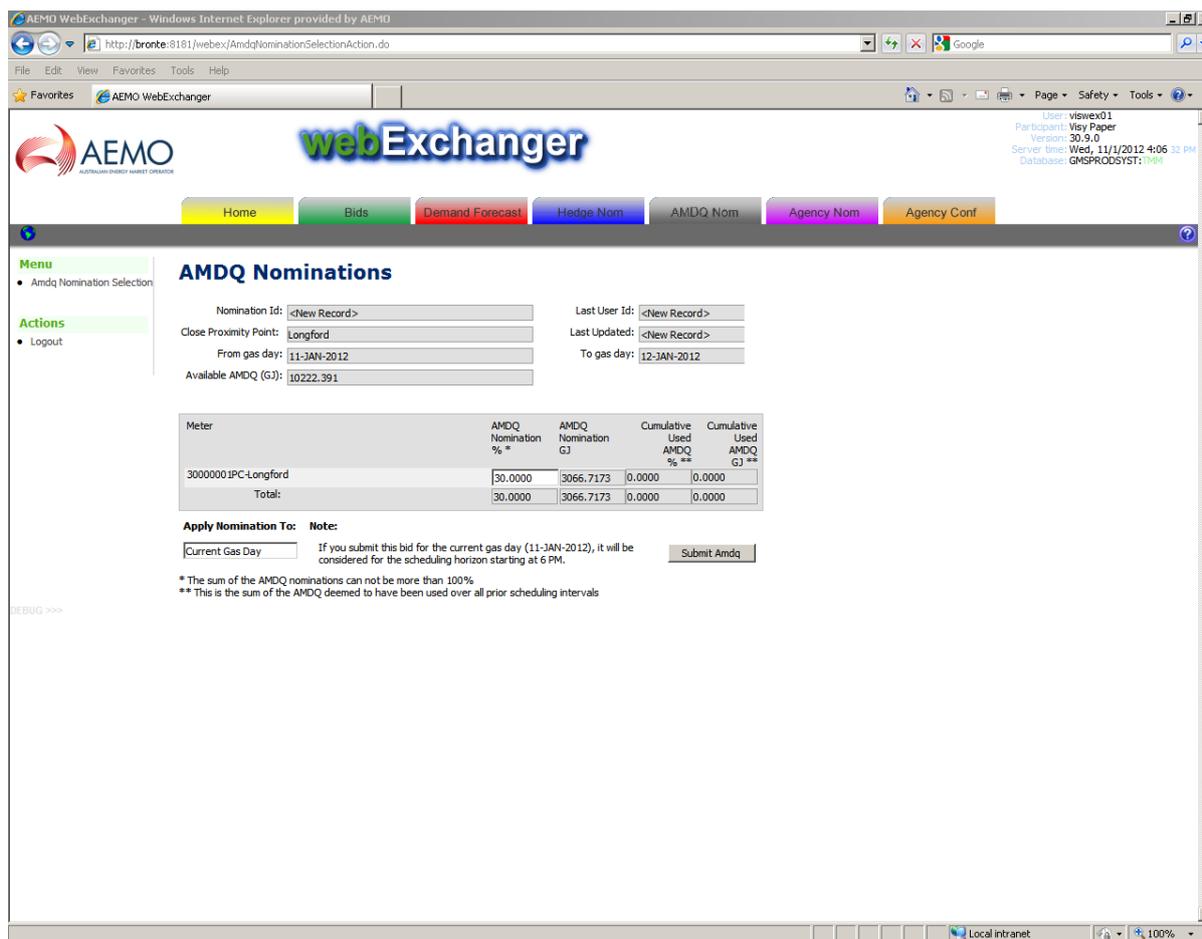
Figure 7-7   WebExchanger AMDQ Nomination input screen

7.5.6   Accredited bid constraints

Bid constraints must be accredited by AEMO before they can be applied to specific injection and withdrawal points in the DTS. These constraints reflect:

- The flexibility of each individual MP to respond to AEMO's changes to scheduling instructions during the gas day.

- The physical and contractual limitations at these injection and controllable withdrawal points.

These constraints can include:

- Maximum and minimum hourly flow.

- Hourly ramp-up and ramp-down rates.

- Hourly response time—the time the MP requires to respond to a reschedule.

- Bid expiration time—the time of the day beyond which the MP cannot respond to a reschedule.

- Fixed schedule quantities (schedule restriction).

- Flexible response.

- Nominated supply source of an injection point for a supply and demand point constraint (SDPC).

This input data is required to produce the optimal MCE solution for each gas schedule.

7.6   AEMO's inputs

AEMO's key inputs to the scheduling process include:

- AEMO's demand forecasts and demand forecast overrides (when required).

- Supply and demand point constraints (SDPC) and directional flow point constraints (DFPC).

- End-of-day (EOD) linepack target.

- Intraday adjustments for injection or controllable withdrawals.

- Other relevant input data.

7.6.1   Demand forecast overrides

Prior to issuing pricing and operating schedules, AEMO assesses demand forecasts as follows:

- AEMO prepares hourly forecasts for uncontrollable withdrawals based on weather forecasts from the Bureau of Meteorology.

- AEMO compares its forecasts with the aggregate demand forecasts provided by all MPs.

- If they differ, AEMO determines whether to override the MPs' aggregate demand forecasts.

AEMO's hourly demand overrides can be positive or negative depending on whether MPs collectively under- or over-forecast uncontrollable demand by specified levels. See Section 15.2 and *Demand Override Methodology* [9] for more details about how AEMO applies the override.

7.6.2   Supply and demand point constraints

AEMO can apply a supply and demand point constraint (SDPC) to reflect a contractual, physical, or operating constraint at an injection or withdrawal point that needs to be considered during scheduling. SDPCs consist of:

- Injection point constraints that apply to the aggregate schedules on all injectors at an injection point—for example, plant or pipeline capacity limits.

- Injection point constraints that selectively constrain scheduled injections at a particular supply source at an injection point, where that injection point has multiple supply sources—for example, an unplanned outage of an upstream gas plant.

- Demand point constraints, which apply to the aggregate scheduled withdrawals at a given withdrawal point—for example, an export capacity limitation.

SDPCs are used in two ways:

- By the MCE, to represent the maximum injection or withdrawal capacity at the related injection or withdrawal points.

- By AEMO, to prescribe an overriding set of constraints on the collective bids at a point.

AEMO sets the SDPC parameters according to information supplied by MPs, including the terms and conditions of the operating agreements between AEMO and MPs and the input data provided directly from MPs.

7.6.3   Directional flow point constraint

AEMO can also apply a directional flow point constraint (DFPC) to a group of injection and withdrawal points on a pipeline (typically at the same location) such that a net direction of flow can be enforced for that pipeline with a specified flow limit. Maximum hourly and maximum daily constraints can be specified in either or both flow directions, which are taken into account during the preparation of a schedule.

This feature allows for scheduled flows to be optimised in either or both directions subject to physical limits specified in operating agreements or operational conditions on the day.

AEMO sets the DFPC parameters according to information supplied by MPs, including the terms and conditions of the operating agreements between AEMO and MPs and the input data provided directly from MPs.

7.6.4   End-of-day linepack target

Although injection rates are relatively constant over the gas day, system linepack varies due to variable withdrawal rates.

A significant proportion of system linepack is required to meet minimum pressure obligations around the system, as prescribed in the system security guidelines. And excess system linepack can increase pressures to the extent that injections into the pipeline need to be backed-off, which can cause problems for production facilities.

Within these limits, system linepack acts as an interim source of stored gas during times when hourly demand exceeds the aggregate injection rate. System linepack is normally restored overnight when demand is lower than the aggregate injection rate.

Hence, system linepack must be carefully managed to ensure the efficient and safe operation of the overall system.

To achieve this, AEMO sets an end-of-day (EOD) linepack target for the system as a whole, and, might also set EOD linepack targets for individual withdrawal zones, if required. The current EOD system linepack target is approximately 340 TJ in summer and 360 TJ in winter. AEMO might change this target from time to time if considered necessary to maintain efficient and safe system operational conditions.

7.6.5   Intraday adjustments for injections or controllable withdrawals

Gas suppliers typically operate under contracts that commit them to deliver into the DTS a contractual quantity of gas over the gas day. Producers might over-inject later in the day if they under-inject in the first part of the day, and still meet their contractual daily nominations or quantities. The same applies to the withdrawal side—for example, at interconnected pipelines.

In such cases, AEMO can apply an intraday quantity difference adjustment (QDIFF) when producing gas schedules, which recognises that the supplier or withdrawer will make up any shortfall or surplus (against the scheduled quantity) over the gas day. Hence, the QDIFF prevents additional or less gas being rescheduled as a result of deviation from an earlier schedule.

QDIFF is limited by system security considerations. If the deviations are large and might cause a threat to system security, then peak shaving gas might be needed to maintain system security.

7.6.6   Other inputs

Other scheduling inputs that are required by the MCE include:

- Compressor commitment

- MCE reference data—node configuration, withdrawal zones, pipe segments, linepack zones, compressor characteristics

- Operational data—nodal pressures

7.7   Scheduling outputs

For each standard schedule, AEMO produces a pricing schedule (PS) and an operating schedule (OS). The quantities scheduled in the PS (to determine the market price) can differ from the quantities scheduled in the OS (to determine injection and withdrawal quantities). These differences lead to ancillary payments, which are paid to MPs who flow gas that was bid above the market price when required to satisfy the operational schedule.

7.7.1   Pricing schedules

The PS is generated by representing the DTS as an infinite gas reservoir without physical constraints on pipeline pressures or on the quantities of gas that can be transported from one point in the system to another. Gas withdrawals (forecast demand plus controllable withdrawals) are met by the cheapest gas bid into the system.

The market price is determined by the marginal price of the cumulative injection bid quantities that are required to meet the aggregate of all MPs' demand forecasts and controllable withdrawal bids. The process takes account of each MP's accreditation for the bids, SDPCs, DFPCs, and target linepack change for the gas day.

Figure 7-8 illustrates how the market price is determined. The example assumes that:

- The BOD and EOD linepack are equal (360TJ).

- The total withdrawals determined by the MCE are 550 TJ, which includes both uncontrollable and controllable withdrawals.

Injection bid quantities are stacked in increasing order of bid price. Uncontrollable withdrawals are priced at VOLL. And controllable withdrawals are stacked in decreasing order of bid price. The market price is at the intersection of the injection and withdrawal bids, which in this example equals 2.72 $/GJ.

A PS is produced for each of the five standard schedules. The market price for an ad hoc schedule is the same as the last standard schedule issued prior to that ad hoc schedule.
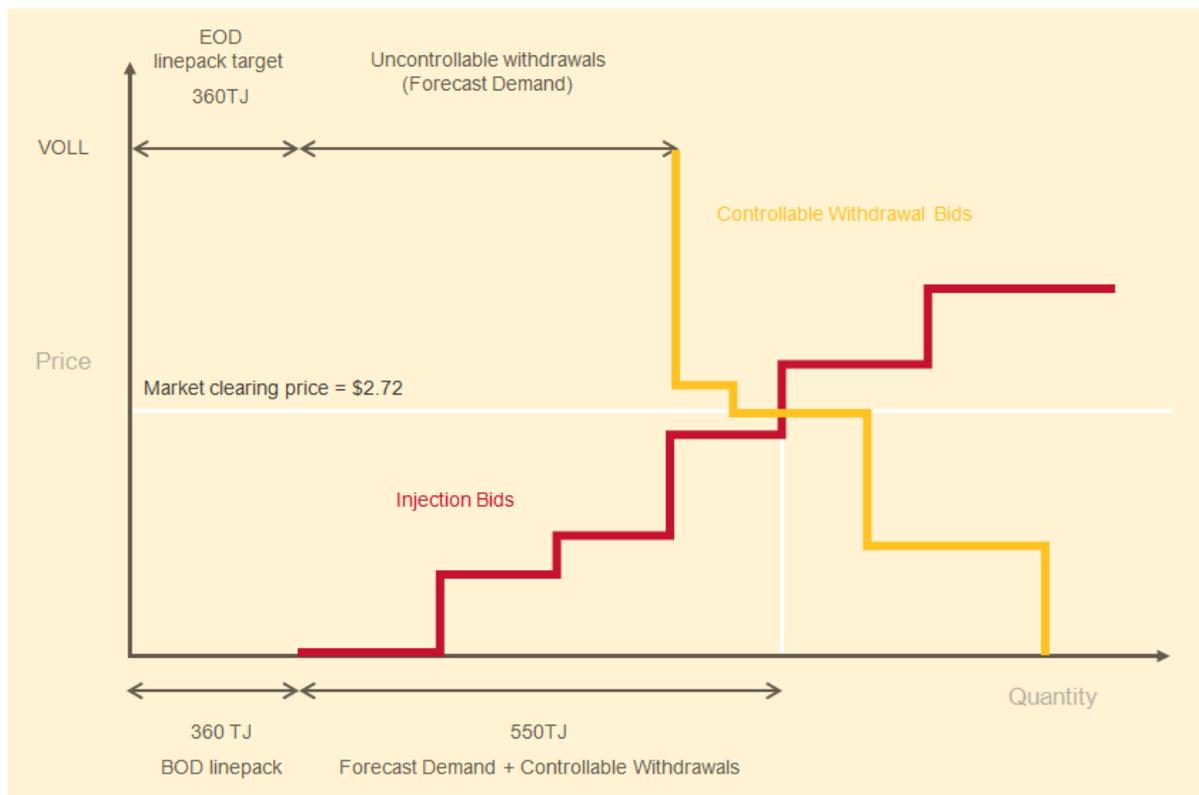
Figure 7-8   Determining the market price

7.7.2   Operating Schedules

The key outputs from the operating schedule (OS) are the quantities that AEMO instructs each MP to inject or withdraw at each injection or withdrawal point.

The MCE uses a simplified physical pipeline model of the DTS, in which system connection points are grouped into a smaller number of nodes. The OS takes into account physical pipeline constraints, linepack distribution in the DTS, and system limits on pressures and gas flows applicable to each node.

When there are constraints in the system, it is not always possible to schedule the cheapest source of gas to meet the total demand. In such cases, more expensive gas must be scheduled to meet demand, which displaces cheaper gas that was notionally supplied to determine the market price. Hence, the scheduled quantities in the pricing and operating schedules are sometimes different. These differences give rise to ancillary payments, which cover the cost of using more expensive gas. For more information about ancillary payments, see Chapter 13.

Figure 7-9 illustrates how the quantities in each scheduling interval can change over the course of the gas day. Scheduled quantities to the left of the solid line cannot change in a later scheduling interval. The colours indicate:

- White (to the right of the solid line). Scheduled quantities can change in a later schedule. Actual quantities are unknown.

- Red (immediately left of the solid line). Scheduled quantities cannot change. Actual quantities are unknown.

- Grey (to the left of the red area). Scheduled quantities cannot change. Actual quantities are known.
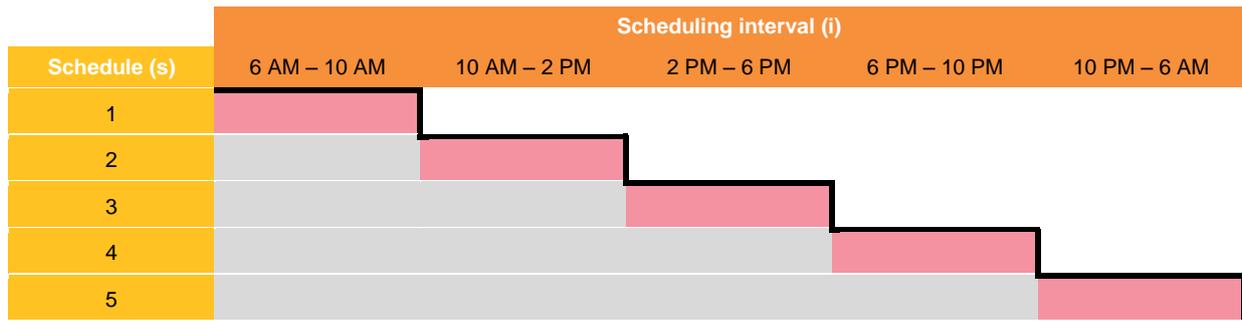
Figure 7-9   Standard schedules and scheduling intervals

A horizontal sum (for all scheduling intervals at a schedule) gives the total daily scheduled quantity at that time.

8 Metering

Metering is the process by which the quantity and quality of gas flowing through the DTS is measured, which are critical to the daily functioning of the system and the market.

In this chapter:

- Metering installations

- Metering register

- Metering database

- Conversion to energy

- Metering installations

8.1   Metering installations

An MP who injects or withdraws gas from any part of the transmission or distribution system must ensure that the connection point or delivery point, including deliveries to Tariff D customers, is properly metered. The MP must ensure that:

- There is a metering installation at that connection or distribution delivery point.

- The metering installation is installed in accordance with the NGR.

- The metering installation is registered with AEMO.

For more information about installation database procedures, refer to [38] in Appendix B.

Normally, a distributor or the DTSSP (APA-GasNet) is responsible (the "responsible person") for providing a metering installation. The responsible person must, in accordance with the NGR:

- Ensure that its metering installations are properly installed, maintained, and registered.

- Ensure the accuracy of each metering installation meets all requirements and are calibrated in accordance with the published standard.

- Provide remote monitoring facilities as required by AEMO.

- Provide AEMO with the information for the metering register (see Section 8.2).

- Create, maintain and administer an installation database for all its metering installations.

The installation database must contain, for each metering installation, the following details:

- Metering point reference details

- The identity and characteristics of metering equipment

- Data communication details

8.2 Metering register

AEMO maintains a metering register of all metering installations that provide metering data used for settlement purposes. The metering register contains the following information:

- Meter identification

- Location in market—the geographical or market groupings the meter installation belongs to

- Associated parties—for example, the responsible person, the distributor, and MPs

8.3 Metering database

AEMO maintains a metering database containing information for each metering installation registered with AEMO. The metering database contains metering data, energy data, energy calculations, gas quality data, substituted data, and other data provided to AEMO for settlement purposes.

8.4 Conversion to energy

Most gas meters measure gas volumes. These values must be converted to energy for wholesale market settlement purposes. A number of strategically located gas chronometers are installed to measure gas composition and gas heating values. The data from the chronometers is used, in conjunction with pressures and temperature, to convert metered volumes to energy. The travel time of gas from key injection points (where the gas chronometers are located) to withdrawal points is calculated, which enables the delivered heating value of gas to be determined on an hourly basis.

For more information about metering, refer to references [31] through [40].

9 Overview of the Settlement Process

The settlement process encompasses the numerous subprocesses involved in billing and settlement of transactions between MPs and AEMO. AEMO must determine for each schedule and each MP:

- Imbalance quantities and payments (Chapter 10)

- Deviation quantities and payments (Chapter 11)

- Linepack account quantities and payments (Chapter 12)

- Ancillary quantities and payments (Chapter 13)

- Uplift quantities and payments (chapters 14 and 15)

- Market fees (see *National Gas Rules* Part 15A Division 3 [44])

Figure 9-1 summarises these key settlement processes.

Provisional metering data for a given gas day is available 3 business days after the end of the gas day. Further validation and substitution of the data is performed over the following 6 to 7 weeks. AEMO then issues a final settlement statement to each MP.

MPs are required to pay within 2 business days upon receiving the final settlement statement or a stated date for a revision statement. To assist MPs, AEMO calculates and issues various estimates of the final settlement amounts to each MP in the interim period. These include:

- Estimates for imbalance, deviation, ancillary, and uplift payments 3 business days after the gas day

- A preliminary settlement statement 7 business days after the end of the month

- A final settlement statement 18 business days after the end of the month

In addition, AEMO can issue, if required:

- A revised settlement statement 118 business days after the end of the month

- An ad hoc revision statement up to 18 months after the revised settlement
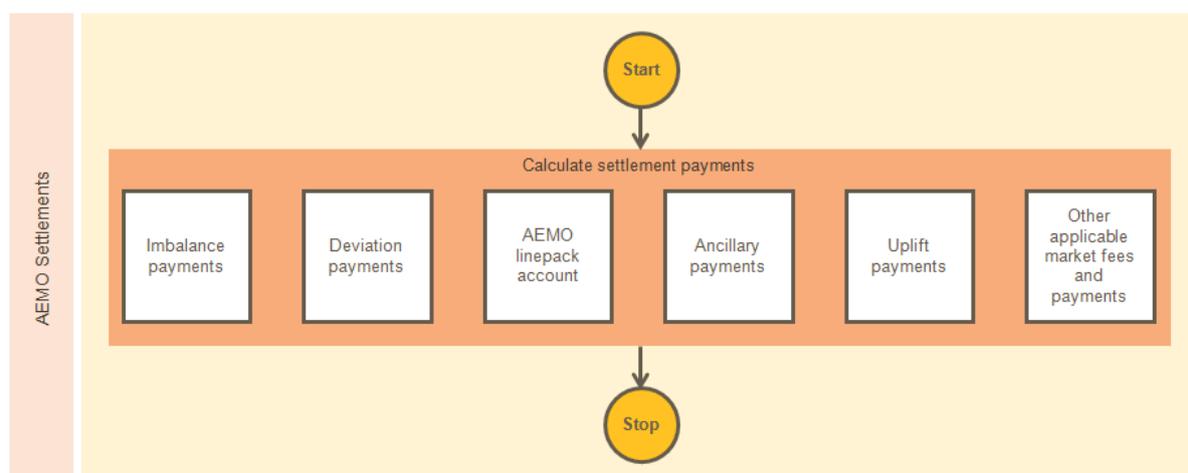
Figure 9-1   Settlement processes

Worked examples are provided in the following chapters to explain calculations of these payments. To keep these calculations simple, the examples assume that there are only two MPs.

Settlement equations

The equations shown in this guide are simplified for the purpose of this guide only and do not account for all possible outcomes. For a complete formulation of the settlement equations, always refer to the relevant section of the *National Gas Rules*. The following conventions have been used in the equations that follow:

p is a market participant

s is a schedule, where s=1 is the 6 AM schedule

i is a scheduling interval, where i=1 is the 6 AM to 10 AM scheduling interval

k is a bid step

And the abbreviated expression $\sum_s Q_s$ is read as "the sum of Q for all values of s".

10 Imbalance Payments

In general, MPs endeavour to balance their daily gas injections and withdrawals to avoid exposure to the spot market. An MP who injects more gas than it withdraws is selling gas to the gas market, whereas an MP who withdraws more gas than it injects is buying gas from the market. MPs are paid or pay the costs for the imbalance quantities in the form of daily imbalance payments (IP).

In this chapter:

- Calculating imbalance payments

- A worked example

10.1 Calculating imbalance payments

The IP for each MP is calculated by the imbalance quantity in the 6 AM schedule at the 6 AM market price plus incremental changes to the imbalance quantity in subsequent schedules at the rescheduled price. An imbalance can be positive (MP pays AEMO) or negative (AEMO pays MP).

Equations are simplified for the purpose of this example and do not necessarily account for all possible outcomes. For the complete formulation, refer to the NGR.

In the following equations, for each market participant:

s is the schedule, where $s=1$ is the 6 AM schedule
P_s is the market price in \$/GJ in schedule s
QWS_s is the scheduled withdrawal quantity in GJ in schedule s
QIS_s is the scheduled injection quantity in GJ in schedule s
IQ_1 is the imbalance quantity in GJ in schedule 1
ΔIQ_s is the imbalance quantity change in GJ in schedule s
IP_s is the imbalance payment in \$ in schedule s

Note that a "schedule" contains both an operating schedule, which provides the scheduled injection and withdrawal quantities, and a pricing schedule, which provides the market price.

For the first (s=1) schedule, which covers the entire gas day, the IP is calculated by:

$$IP_1 = IQ_1 \times P_1 = (QWS_1 - QIS_1) \times P_1 \qquad \text{..} (1)$$

For later schedules (s>1), the IP captures the change in IP relative to the previous schedule and is calculated by:

$$IP_s = \Delta IQ_s \times P_s = \big((QWS_s - QWS_{s-1}) - (QIS_s - QIS_{s-1})\big) \times P_s \qquad \text{.......................................} (2)$$

And the total IP for that MP for that gas day is:

$$IP = \sum_s IP_s \qquad \text{...} (3)$$

Thus, if an MP withdraws and injects the same quantity of gas across the entire day, the IP will be zero. If it withdraws more gas than it injects, the IP will be positive—the MP has purchased gas from the gas market and must pay AEMO for the quantity it purchased. And if it withdraws less gas than it injects, the IP will be negative—the MP has sold gas to the gas market and is paid by AEMO for the quantity of gas sold.

10.2   A worked example

Table 10.1 shows a simple example of the calculations of imbalance quantities and payments for a single MP.

Table 10.1   Calculation of imbalance payment

Schedule	Scheduled injection	Scheduled withdrawal	Market price	Imbalance quantity	Change in Imbalance	Imbalance payment	See equation
	GJ	GJ	$/GJ	GJ	GJ	$	
s	QIS	QWS	P	IQ	ΔIQ	IP	
1	161	142	6.50	−19.0	−	−123.50	1
2	161	139	5.60	−22.0	−3.0	−16.80	2
3	160	139	4.50	−21.0	1.0	4.50	2
4	160	139	3.10	−21.0	0.0	0.00	2
5	160	139	2.50	−21.0	0.0	0.00	2
Daily total						135.80	3

Negative amounts are paid by AEMO to the MP

Note that the quantity in schedule s is the sum of the quantities for all scheduling intervals $i=1$ to $final$ over the gas day—that is, $QIS_s = \sum_{i=1}^{final} QIS_s(i)$ or in the abbreviated form $QIS_s = \sum_i QIS_s(i)$.

6 AM schedule (s=1)

The MP is scheduled to inject 161 GJ (QIS_1) and withdraw 142 GJ (QWS_1) of gas in the 6 AM ($s=1$) schedule, resulting in a negative imbalance quantity of −19 GJ (IQ_1). The market price is 6.50 $/GJ ($P_1$). Applying Equation 1, the IP is calculated by:

$$IP_1 = (142 − 161) \times 6.50 = −19 \times 6.50 = −123.5$$

In this case, the MP sells 19 GJ of gas to the gas market and so receives a payment from AEMO of $123.50.

10 AM schedule (s=2)

At the next schedule, the MP revises its demand forecasts (or controllable withdrawals) and reduces its total scheduled withdrawals by 3 GJ to 139 GJ (QWS_2), but the scheduled injections (QIS_2) are unchanged at 161 GJ. The market price is 5.60 $/GJ ($P_2$). Applying Equation 2, the IP is calculated by:

$$IP_2 = \big((139 − 161) − (161 − 161)\big) \times 5.60 = −3 \times 5.60 = −16.8$$

In this case, the MP sells an extra 3 GJ more than the 19 GJ it sold in the 6 AM schedule and is paid an additional $16.80.

2 PM schedule (s=3)

At the next schedule, the MP reduces its injection by 1 GJ to 160 GJ (QIS_3), but the scheduled withdrawals (QWS_3) are unchanged at 139 GJ. The market price is 4.50 $/GJ ($P_3$). Applying Equation 2, the IP is calculated by:

$$IP_3 = \big((139 - 139) - (160 - 161)\big) \times 4.50 = 1 \times 4.50 = 4.5$$

In this case, the MP buys back 1 GJ and this time pays AEMO $4.50. In effect, the MP has bought back gas at 2 PM for 4.50 $/GJ that it sold to the market at 10 AM for 5.60 $/GJ, thereby making a profit of $1.10 for the 1 GJ of gas it purchased.

6 PM and 10 PM schedules (s=4,5)

There are no revisions to the scheduled injections and withdrawals in subsequent schedules. The IP for these schedules is zero.

Total IP

The total IP for the gas day is the sum of the IPs across the five schedules (Equation 3). And so AEMO pays the MP a total daily IP of $135.80 for that gas day.

11 Deviation Payments

When MPs deviate from their demand forecasts and scheduled quantities (injections and withdrawals) in a given schedule, it has physical and financial impacts on the outcomes of the next schedule. The differences between an MP's scheduled and actual behaviour are accounted for with deviation payments (DP).

For example, if an MP under-forecasts their demand (or under-schedules injections) in the 6 AM schedule, this decreases the linepack and requires more gas to be injected at the 10 AM schedule. This might also increase the gas market price. Similarly, deviations in the 10 AM scheduled quantities and demand forecasts will affect the 2 PM market outcomes.

Deviation payments also provide MPs with a tool to trade linepack between schedules by managing their net positions in supply and demand.

In this chapter:

* Calculating imbalance payments

* A worked example

11.1   Calculating deviation payments

For a given schedule, the deviation payment is calculated by multiplying the net deviation quantity in that schedule by the market price in the next schedule. Deviation quantities and payments can be positive (MP pays AEMO) or negative (AEMO pays MP).

Equations are simplified for the purpose of this example and do not necessarily account for all possible outcomes. For the complete formulation, refer to the NGR.

In the following equation, for each market participant:

s is the schedule, where $s=1$ is the 6 AM schedule
i is the scheduling interval, where $i=1$ is the 6 AM to 10 AM scheduling interval
P_s is the market price in \$/GJ in schedule s
$QWS_s(i)$ is the scheduled withdrawal quantity in GJ at scheduling interval i in schedule s
$QIS_s(i)$ is the scheduled injection quantity in GJ at scheduling interval i in schedule s
$QWA_s(i)$ is the actual withdrawal quantity in GJ at scheduling interval i in schedule s
$QIA_s(i)$ is the actual injection quantity in GJ at scheduling interval i in schedule s
DQ_s is the net deviation quantity in GJ in schedule s
DP_s is the deviation payment in \$ in schedule s

Note that a "schedule" contains both an operating schedule, which provides the scheduled injection and withdrawal quantities, and a pricing schedule, which provides the market price.

For each scheduling interval s, the deviation payment is calculated by:

$$DP_s = DQ_s \times P_{s+1} = \left(\left(QWA_s(i=s) - QWS_s(i=s) \right) - \left(QIA_s(i=s) - QIS_s(i=s) \right) \right) \times P_{s+1} \quad\text{.....................} (4)$$

For the final scheduling interval in the gas day, the next market price is taken from the first scheduling interval in the next gas day.

11.2 A worked example

Referring to Equation 4, the expression $QWS_s(i=s)$ is illustrated in Table 11.1, which shows the scheduling interval i that is used at each schedule s for the calculation of deviation payments. Only the scheduled withdrawal quantities are shown in this table, but the same process applies to the other quantities used in the calculation.

Table 11.1   Scheduled withdrawal quantities used in calculation of deviation payments

QWS	Scheduling interval (i)				
Schedule (s)	6 AM – 10 AM	10 AM – 2 PM	2 PM – 6 PM	6 PM – 10 PM	10 PM – 6 AM
	1	2	3	4	5
1	31				
2		24			
3			25		
4				31	
5					28

In the example shown in Table 11.2, the MP has negative deviation quantities in the first (s = 1) (6 AM) and fourth (s = 4) (6 PM) schedules and is paid for these additional quantities at the 10 AM (s = 2) and 10 PM (s = 5) schedule prices respectively. However, the MP must pay for the positive deviations in the other schedules.

Table 11.2   Calculation of deviation payments

Schedule (s) and interval (i)	Actual withdrawal	Scheduled withdrawal	Actual injection	Scheduled injection	Net deviation	Market price	Next market price	Deviation payment
	GJ	GJ	GJ	GJ	GJ	$/GJ	$/GJ	$
s,i	QWA	QWS	QIA	QIS	DQ	P_s	P_{s+1}	DP
1,1	28	31	31	28	–6	6.50	5.60	–33.60
2,2	23	24	24	29	4	5.60	4.50	18.00
3,3	24	25	25	29	3	4.50	3.10	9.30
4,4	31	31	30	29	–1	3.10	2.50	–2.50
5,5	29	28	30	45	16	2.50	3.10	49.60
1,1 (d+1)						3.10		
Daily total	135	139	140	160	16			40.80

Negative amounts are paid by AEMO to the MP

For example, in the 6 AM ($s=1$) schedule, the MP is scheduled to inject 28 GJ (QIS_1) and withdraw 31 GJ (QWS_1). The actual injection is 31 GJ (QIA_1), and the actual withdrawal (QWA_1) is 28 GJ. The market price in the next schedule is 5.60 $/GJ ($P_2$). Applying Equation 4, the DP in the 6 AM schedule is calculated by:

$$DP_1 = (28 - 31) - (31 - 28) \times 5.60 = -6 \times 5.60 = -33.6$$

The total DP for the gas day is the sum of the DPs across the five schedules. And so the MP pays AEMO a total DP of $40.80 for that gas day.

12 AEMO Linepack Account

The AEMO linepack account (LPA) is a market balancing mechanism that accounts for imbalance and deviation payments and the costs associated with unaccounted-for-gas (UAFG).

When MPs deviate from their schedules, the gas is either removed from or added to the system linepack. AEMO purchases or sells this gas at the market price of the current schedule through the LPA. In the next schedule, the LPA resells or repurchases the change in linepack gas that occurred in the previous schedule at the market price of the current schedule.

Because the prices at which linepack is purchased and sold are usually different, these balancing transactions can build up a surplus or deficit of funds in the LPA. The LPA surplus or deficit is cleared daily by apportioning the surplus or deficit to MPs based on their total actual withdrawals for the day.

In this chapter:

- Calculating linepack account

- Allocating LPA to market participants

- A worked example

12.1   Calculating linepack account

The LPA for each schedule is the sum of all MPs' imbalance and deviation payments for that schedule.

Equations are simplified for the purpose of this example and do not necessarily account for all possible outcomes. For the complete formulation, refer to the NGR.

In the following equations, for each gas day:

$IP_s(p)$ is the imbalance payment in \$ for market participant p in schedule s
$DP_s(p)$ is the deviation payment in \$ for market participant p in schedule s

For each schedule s, the schedule LPA is calculated by:

$$LPA_s = \sum_p IP_s(p) + \sum_p DP_s(p) \quad\text{...}\text{(5)}$$

And for each gas day, the LPA is calculated by:

$$LPA = \sum_s LPA_s \quad\text{..}\text{(6)}$$

12.2 Allocating LPA to market participants

The LPA accumulates over the day with the end-of-day balance apportioned to each MP according to their share of actual withdrawals for that day. The cumulative linepack account can be positive (resulting in a surplus payment to all MPs) or negative (resulting in a deficit funded by all MPs).

Equations are simplified for the purpose of this example and do not necessarily account for all possible outcomes. For the complete formulation, refer to the NGR.

In the following equation, for each gas day:

> QWA_p is the actual withdrawal quantity in GJ for market participant p
>
> LPA is accumulated linepack account amount in \$
>
> LPP_p is the linepack (deficit or surplus) payment in \$ for market participant p

For market participant p, the linepack payment is calculated by:

$$LPP_p = LPA \times \left(QWA_p \middle/ \sum_p QWA_p \right) \quad \text{.. (7)}$$

12.3 A worked example

Table 12.1 shows the LPA calculations for each schedule of a gas day where there are two market participants A and B. The IPs and DPs for market participant B were calculated earlier in Table 10.1 and Table 11.2. In this case, the net LPA payment for the gas day is a deficit of \$3.50 (LPA).

Table 12.1   Calculation of linepack account

Schedule	Market participant A		Market participant B		Total			See equation
	Imbalance payment $	Deviation payment $	Imbalance payment $	Deviation payment $	Imbalance payment $	Deviation payment $	Linepack account payment $	
s	$IP_s(A)$	$DP_s(A)$	$IP_s(B)$	$DP_s(B)$	$\sum_p IP_s$	$\sum_p DP_s$	LPA_s	
1	58.5	11.2	−123.5	−33.6	−65.0	−22.4	−87.4	5
2	0.0	−9.0	−16.8	18.0	−16.8	9.0	−7.8	5
3	13.5	−6.2	4.5	9.3	18.0	3.1	21.1	5
4	15.5	−7.5	0.0	−2.5	15.5	−10.0	5.5	5
5	0.0	15.5	0.0	49.6	0.0	65.1	65.1	5
Daily total	87.5	4.0	−135.8	40.8	−48.3	44.8	−3.5	6

Referring to Table 12.2, A's actual total withdrawal is 118 GJ (QWA_A) and B's is 135 GJ (QWA_B). Hence A funds 46% and B funds 54% of the LPA deficit.

Table 12.2   Allocation of daily LPA to market participants

Market participant	Actual daily withdrawal (GJ)	Proportion of actual daily withdrawal	Daily linepack payment $	See equation
p	QWA_p	$QWA_p / \sum_p QWA_p$	LPP_p	
A	118	0.47	1.63	7
B	135	0.53	1.87	7
Daily total	253	1.00	3.50	7

Negative amounts are paid by AEMO to the MP

13 Ancillary payments

As discussed in Section 7.7, it is not always possible to schedule the cheapest gas to meet the required demand for a given gas day. This usually happens when the system is congested, resulting in gas being scheduled that is more expensive than the market price. Ancillary payments (AP) are compensation payments to MPs who inject gas that was bid above the market price. Although less likely, an AP is also paid when an MP is scheduled to withdraw gas that is more expensive than their bid price.

This section will focus on injection AP. The method for calculating withdrawal AP is similar with some minor differences.

For more information, refer to *Ancillary Payment Procedures* [19], *Ancillary Payment Functional Design* [20], and *National Gas Rules* [44].

The original AP procedure, implemented in February 2007, was enhanced in May 2008 following the experience in winter 2007. The enhancements are designed to improve market efficiency with the additions of the AP clawback and AP flip-flop algorithms. A further enhancement was made in April 2012 to ensure that market participants are protected against potential financial impacts by rebidding reduced quantities to comply with the NGR.

In this chapter:

- Overview of ancillary payment calculations

- Calculating initial ancillary payments

- The AP clawback algorithm

- The AP flip-flop algorithm

13.1   Overview of ancillary payment calculations

The steps involved in the AP calculations are shown Figure 13-1 and include:

- Calculation of initial APs (see Section 13.2)

- Adjusting the initial APs for AP clawback (see Section 13.3)

- Applying the AP flip- flop algorithm to APs that have been adjusted for clawback (see Section 13.4)
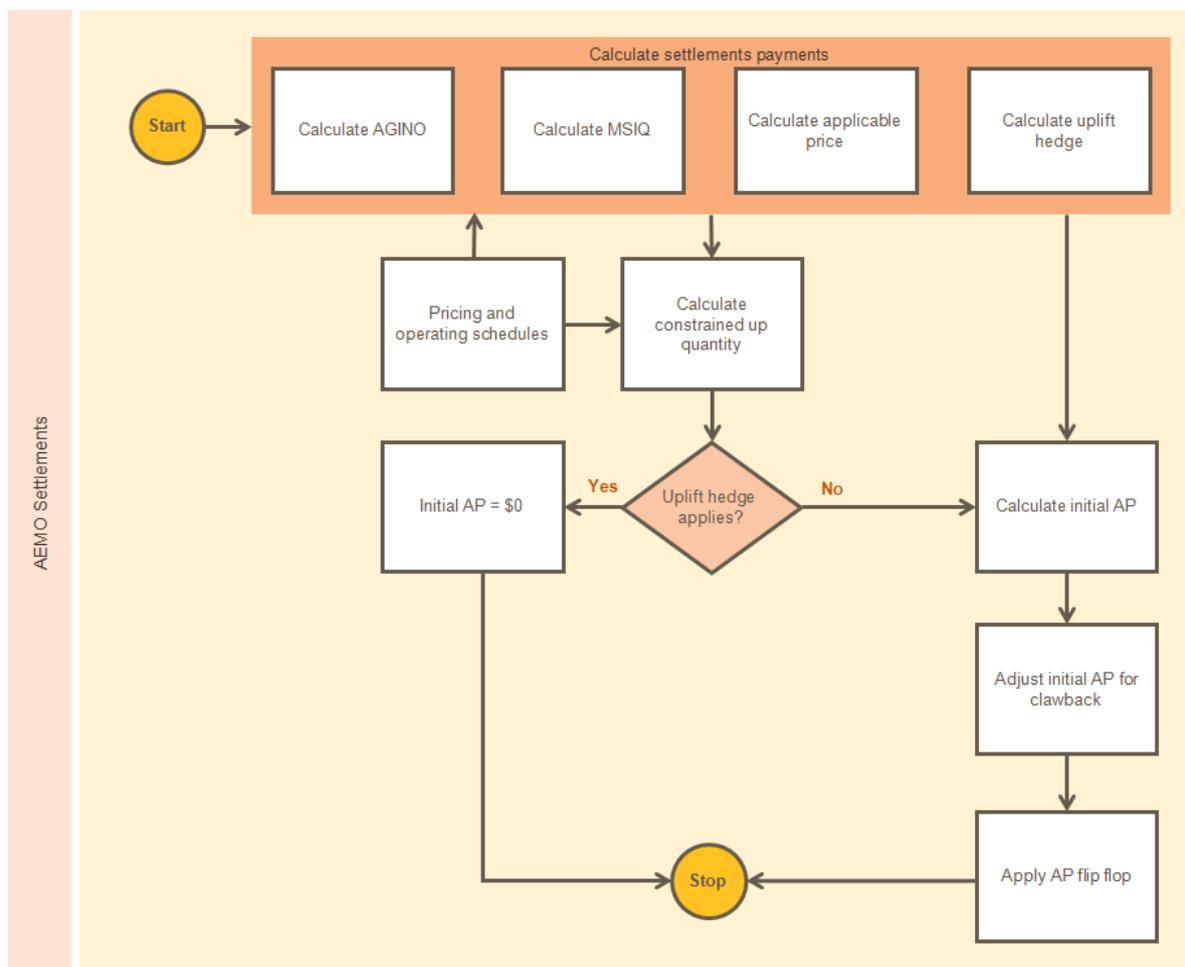
Figure 13-1   Ancillary payment calculations

13.2   Calculating initial ancillary payments

Initial ancillary payments (IAP) are calculated for each bid step at each injection point for each schedule for each gas day.

Equations are simplified for the purpose of this example and do not necessarily account for all possible outcomes. For the complete formulation, refer to the NGR.

In the following equations, for each market participant:

s is the schedule, where $s=1$ is the 6 AM schedule
$b_s(k)$ is the price in \$/GJ in bid step k in schedule s
P_s is the market price in \$/GJ in schedule s
$CUIQ_s$ is the constrained-up injection quantity in GJ in schedule s (see Section 13.2.1)

For the BOD ($s=1$) schedule, the initial AP is calculated for each bid step k by:

$$IAP_1(k) = CUIQ_1 \times MAX(0, b_1(k) - P_1) \dotfill (8)$$

For each subsequent schedule, the initial AP for each bid step is calculated based on the change in constrained-up injection quantity (the quantity eligible for AP), which can increase or decrease to reflect the extent of system congestion in later schedules.

So, for each schedule $s>1$, the initial AP is calculated for each bid step k by:

$$IAP_s(k) = (CUIQ_s - CUIQ_{s-1}) \times MAX(0, b_s(k) - P_s) \dotfill (9)$$

The initial APs for the first schedule of the gas day, if any occur, are always positive, but can be positive or negative in later schedules. For example, if the CUIQ decreases in a later schedule, the change in CUIQ will be negative and so will be the initial APs. See Section 13.2.6 for more details about negative APs.

13.2.1 Constrained-up injection quantity (CUIQ)

The constrained-up injection quantity (CUIQ) is the quantity of gas that is eligible for an AP (shown as the blue shaded area in Figure 13-2 below).
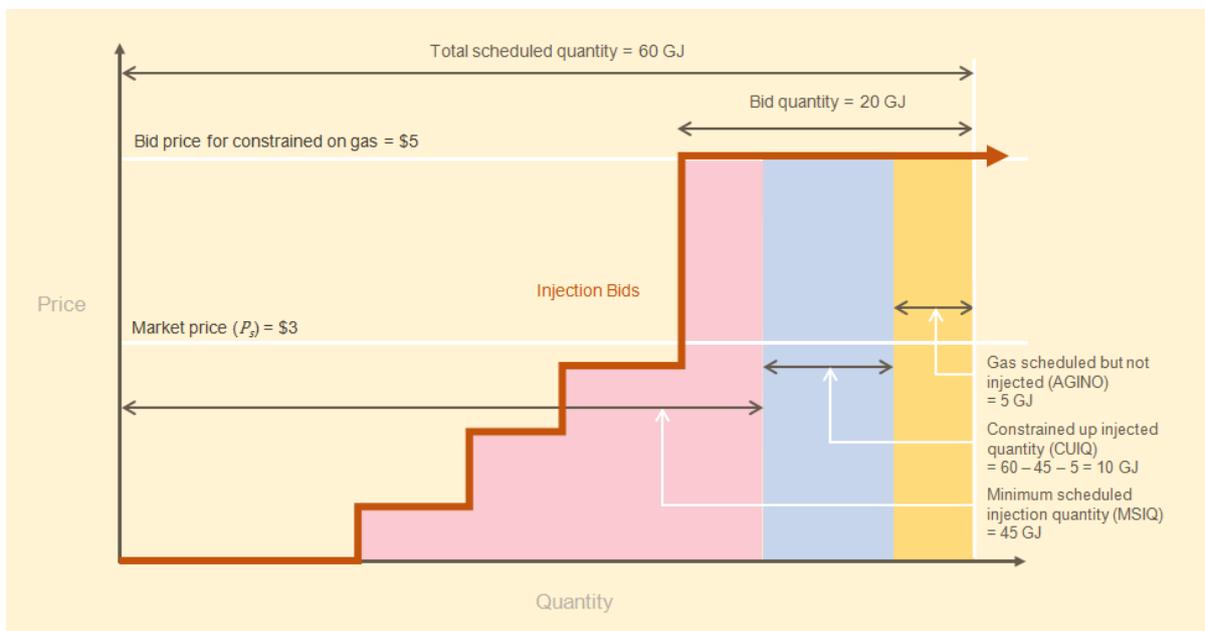
Figure 13-2   Calculation of CUIQ

Where, for each MP:

   QIS is the scheduled injection quantity in GJ.

   $AGINO$ is the actual gas injection negative offset in GJ—shaded yellow in previous figure—which is the quantity that was scheduled but not injected (see Section 13.2.2).

   $MSIQ$ is the minimum scheduled injection quantity in GJ—shaded red in previous figure—which is an MP's self-imposed injection constraint (see Section 13.2.3).

The CUIQ is calculated by:

$$CUIQ_s = QIS_s - AGINO_s - MSIQ_s \dotfill (10)$$

In addition, any quantity of the CUIQ used for uplift hedge purposes will not receive an AP (see Chapter 14 for more details).

See Section 13.2.5 for examples of calculations of AP.

13.2.2 Actual gas injection negative offset (AGINO)

If an MP injects less gas than it is scheduled in the OS, it does not receive an AP for the under-injected quantity of gas. This amount is termed the actual gas injection negative offset (AGINO) and is always positive.

The AGINO is calculated for the final schedule and then back-calculated for earlier schedules.

Calculating AGINO for the final schedule

Where,

$QIS_s(k)$ is the scheduled injection quantity in GJ for bid k in schedule s

$QIA_s(k)$ is the actual injection quantity in GJ for bid k in schedule s

For $s=final$, AGINO for each bid step is calculated by:

$$AGINO_s(k) = MAX(0, QIS_s(k) - QIA_s(k)) \dotfill (11)$$

And the total AGINO in the final OS is calculated by:

$$AGINO_{s=final} = \sum_k AGINO_s(k) \dotfill (12)$$

The following examples illustrate calculations of AGINO assuming there are three bid steps in the final schedule.

The example in Table 13.1 shows that an MP is scheduled to inject a total of 30 GJ of gas in the final schedule but only injects 25 GJ. Consequently, the AGINO of 5 GJ in bid step 3 is not entitled to AP.

Table 13.1   Calculation of AGINO by bid steps (scheduled > actual) in final schedule

Bid step	Scheduled injection GJ	Actual Injection GJ	AGINO GJ	See equation
k	$QIS(k)$	$QIA(k)$	$AGINO(k)$	
1	5	5	0	11
2	15	15	0	11
3	10	5	5	11
Total	30	25	5	12

The example in Table 13.2 illustrates the case where the given MP injects 35 GJ in the final schedule—that is, 5 GJ more than the OS. The over-injection of 5 GJ is also not entitled to AP and is not included in the AGINO calculation.

Table 13.2   Calculation of AGINO by bid steps (scheduled < actual) in final schedule

Bid step	Scheduled injection GJ	Actual injection GJ	AGINO GJ	See equation
k	$QIS(k)$	$QIA(k)$	$AGINO(k)$	
1	5.0	5.0	0.0	11
2	15.0	15.0	0.0	11
3	10.0	15.0	0.0	11
Total	30.0	35.0	0.0	12

Calculation of AGINO for earlier schedules

Equations 11 and 12 are only applied to the final schedule, otherwise it might reduce the quantity of gas that is eligible for AP. The AGINOs in earlier schedules are back calculated with respect to changes from the final schedule. This takes into account the changes between the scheduled quantity in the final schedule and the least quantity of gas scheduled in previous schedules.

To calculate the AGINO for the current schedule, prior to the final OS, calculate the least quantity scheduled in all schedules from the current schedule to the final schedule.

$$MinQIS_s = MIN\left(QIS_s, QIS_{s+1}, \ldots, QIS_{s=final}\right) \quad\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(13)$$

And then calculate the difference between the scheduled quantity in the final schedule and the least quantity scheduled. The current schedule AGINO is the difference between the final schedule AGINO and this difference.

$$AGINO_{s<final} = AGINO_{s=final} - \left(QIS_{s=final} - MinQIS_s\right) \quad\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(14)$$

Table 13.3 illustrates the method for calculating AGINO for schedules prior to the final schedule. For the 6 AM schedule (s=1), the MP is scheduled to inject 10 GJ of gas, the least quantity of scheduled gas is 5 GJ (the minimum scheduled quantity across schedules 1 to 5), and the difference between the scheduled quantity in the final OS and the least quantity scheduled is 5 GJ. The AGINO is therefore 0 GJ. This means that all the OS quantity of 10 GJ in the 6 AM schedule is eligible for AP.

Table 13.3   Calculation of AGINO across schedules

	Schedule (s)	1	2	3	4	5 (final)
Scheduled quantity (GJ)	QIS_s	10	5	7	8	10
Least quantity scheduled (GJ)	$MinQIS_s$	5	5	7	8	–
Final OS quantity less least quantity scheduled (GJ)	$QIS_{final} - MinQIS_s$	5	5	3	2	–
AGINO (GJ)	Equations 13–14	0	0	2	3	5
Actual quantity (GJ)	QIA_s	5	5	5	5	5
CUIQ where MSIQ=0 (GJ)	Equation 10	10	5	5	5	5

13.2.3 Minimum scheduled injection quantity (MSIQ)

The minimum schedule injection quantity (MSIQ) is the daily quantity of gas that is injected as a result of constraints that are self-imposed by the MP. These constraints include ramping limits and minimum flow constraints in the pricing schedules—for example, minimum hourly or daily quantities. Because this quantity of gas flows regardless of market price, it is not eligible for an AP.

The MSIQ for each bid step in the final schedule is equal to the pricing schedule quantity for that bid step.

The MSIQ for each bid step in the schedules prior to the final schedule is calculated by:

- If the bid price is higher than the market price, the MSIQ equals the pricing schedule quantity. The rationale is that any scheduled gas in the PS which costs more than the market price would have only flowed because of the MP's imposed constraints.

- If the bid price is less than the market price, the MSIQ is the lesser of the PS quantity for that bid step in that schedule and the MSIQ for that bid step in the following schedule.

Table 13.4 illustrates how MSIQ is calculated for the same bid step across each schedule. Starting from the final (s=5) schedule, the MSIQ equals the PS quantity of 5 GJ. For schedule 4, the bid price is less than the market price, therefore the MSIQ is 5 GJ, being the lesser of the PS quantity (15 GJ) and the MSIQ in the previous (s=5) schedule (5 GJ). For the earlier schedules, bid prices are higher than market prices, and gas can only be scheduled because the MP has requested gas to be injected to satisfy their constraints. Therefore, the MSIQ for the first three schedules equals the PS quantity.

Table 13.4   Calculation of MSIQ across schedules

Schedule (s)	1	2	3	4	5
Bid price ($/GJ)	3.00	3.00	4.00	4.00	4.00
Market price ($/GJ)	2.00	2.00	1.00	5.00	1.00
Pricing schedule quantity (GJ)	10	5	7	15	5
MSIQ (GJ)	10	5	7	5	5

13.2.4 Uplift hedges

Any quantity of gas in the OS that is used as an uplift hedge is not eligible for AP. See Chapter 14 for more information about uplift hedges.

13.2.5 A worked example of initial ancillary payments

Table 13.5 shows an example of the calculations of the initial AP for the BOD schedule. Referring to the columns (A, B, C, and so forth) in Table 13.5, the calculations are based on the following equations:

Column	Parameter	Explanation	Refer to
A	QIS	Scheduled injection quantity	
B	MSIQ	Minimum scheduled injection quantity	Section 13.2.3
C	AGINO	Actual gas injection negative offset	Section 13.2.2
D	CUIQ	Constrained-up injection quantity $D = MAX(0, A - B - C)$	Section 13.2.1, Equation 10

Column	Parameter	Explanation	Refer to
E	Bid step price		
F	Market price		
G	AP price	$G = MAX(0, E - F)$	Section 13.2, Equation 8 (part)
H	Initial AP	$H = G \times D$	Section 13.2, Equation 8
I	Uplift hedge flag	if I = "Y" then $J = 0$	Chapter 14
J	AP	AP adjusted for uplift hedge	

In this example, the total scheduled quantity is 30 GJ. Bid step 1 is used as an uplift hedge and hence is not eligible for an AP. The AP for bid step 2 is $30.00 based on 15 GJ of CUIQ and the applicable price 2.00 $/GJ. The AP for bid step 3 is $20.00 based on the CUIQ of 5 GJ at 4.00 $/GJ.

Table 13.5   Calculation of ancillary payments

Bid step	QIS GJ	MSIQ GJ	AGINO GJ	CUIQ GJ	Bid price $/GJ	Market price $/GJ	AP price $/GJ	IAP $	Uplift hedge flag	AP $
	A	B	C	D	E	F	G	H	I	J
1	5	5	0	0	3.00	3.10	0.00	0.00	Y	0.00
2	15	0	0	15	5.10	3.10	2.00	30.00	N	30.00
3	10	0	5	5	7.10	3.10	4.00	20.00	N	20.00

13.2.6   Negative initial ancillary payments

The initial APs for the first schedule of the gas day, if any occur, are always positive but can be positive or negative in later schedules. Negative initial APs occur if the scheduled quantities in the later schedules decrease (refer to Equation 9 in Section 13.2), which results in a negative change in the calculated CUIQ.

In general, negative APs most likely occur under one of the following situations:

- Negative AP following positive APs (Section 13.2.6.1 "AP flip-flop")

- Negative AP due to rebidding (Section 13.2.6.2 "AP clawback type I")

- Negative AP due to reduced rebid quantity (Section 13.2.6.3 "AP clawback type II")

- Negative AP with no preceding positive APs (Section 13.2.6.4)

For more information about the causes of negative AP, refer to Gas Market Consultative Committee (now Gas Wholesale Consultative Forum) *GMCC07-017-01 Committee paper* (GMCC meeting 124) [24]. For more information about how negative AP is addressed, refer to *GMCC08-084-09 Committee paper* (GMCC meeting 136) [25].

13.2.6.1 AP flip-flop

The example in Table 13.6 illustrates the situation where a negative AP occurs following a positive AP in the previous schedule. It is assumed that there are only two schedules.

In the first schedule,

- The market price is 3.50 $/GJ.

- The MP is scheduled to inject 10 GJ of gas at the bid price of 5.0 $/GJ.

- The MP has sold 10 GJ of gas to the market and receives an IP of $35 ($= 10 \times \$3.50$).

- The MP receives an AP of $15 ($= 10 \times (\$5.00 - \$3.50)$) as a compensation payment for gas injected above the market price.

- The MP receives a net payment of $50 being the sum of total IP and AP.

In the second schedule,

- The market price is 3.00 $/GJ.

- The MP is scheduled to inject 0 GJ.

- The MP buys back 10 GJ of gas from the market (which it sold to the market in the first schedule) and pays an IP of –$30 ($= -10 \times \$3$).

- The MP refunds an AP of –$20 ($= -10 \times (\$5 - \$3)$) because the constrained-up gas is no longer required.

- The MP refunds $50 of IP and AP for the quantity of gas that it has to buy back from the market.

In this example, the total IP is $5 while the total AP is –$5, and so the MP is even overall. However, if the market price fell below 3.00 $/GJ to, for example, 2.50 $/GJ, the AP refund would be –$25 and a total AP of –$10. The MP would be out of pocket by –$5 when IP and AP are considered together.

Note that the initial AP changes sign from positive in the first schedule to negative in the second schedule. This is referred to as "AP flip-flop". The AP flip-flop algorithm was implemented in May 2008 to address the issue of large APs changing sign from one schedule to the next. See Section 13.4 for more details.

Table 13.6   Example of negative AP following positive AP in previous schedule

Bid	1	2	Total
Bid price ($/GJ)	5.00	5.00	
Market price ($/GJ)	3.50	3.00	
Bid quantity (GJ)	10	10	
QIS (GJ)	10	0	
Change in CUIQ (GJ)	10	−10	
IP ($)	35.00	−30.00	5.00
AP ($)	15.00	−20.00	−5.00
Total IP + AP ($)	50.00	−50.00	0.00

13.2.6.2 AP clawback type I

See Section 13.3 for more details of the AP clawback algorithm.

The example in Table 13.7 illustrates the situation where a negative AP occurs because the MP rebids its gas higher in the reschedule. Compared with the example in Table 13.6, the only change is the increased bid price in schedule 2.

The market outcomes and payments for the first schedule are the same as Table 13.6. However, in the second schedule,

- The MP rebids its gas higher at 10 $/GJ, and gas that was scheduled but is yet to be injected in schedule 1 is no longer required.

- The MP has to buy back 10 GJ of gas from the market (that it sold to the market in the first schedule) and pays an IP of –$30 $(= -10 \times \$3)$.

- The MP refunds an AP of –$70 $(= -10 \times (\$10 - \$3))$ because the constrained-up gas is no longer required. The refund is much larger than the initial AP received in the first schedule.

- The MP has to refund $100 of combined IP and AP for the quantity of gas that it has to buy back from the market.

In this example, the total IP is $5 but the total AP is –$55. The total net payment is a loss of –$50 when IPs and APs are considered together. So, by rebidding gas at a higher price in a later schedule, the resulting negative AP can be much larger than the positive AP it receives in earlier schedules.

The AP clawback algorithm was implemented in May 2008 to address the over-recovery of AP when an MP incurs large negative APs by rebidding gas injections at a higher price in reschedules in an attempt to be descheduled or scheduled down.

Table 13.7   Example of negative AP due to rebidding with increased bid price

Bid	1	2	Total
Bid price ($/GJ)	5.00	10.00	
Market price ($/GJ)	3.50	3.00	
Bid quantity (GJ)	10	10	
QIS (GJ)	10	0	
Change in CUIQ (GJ)	10	−10	
IP ($)	35.00	−30.00	5.00
AP ($)	15.00	−70.00	−55.00
Total IP + AP ($)	50.00	−100.00	−50.00

13.2.6.3 AP clawback type II

See Section 13.3 for more details of the AP clawback algorithm.

The example in Table 13.8 illustrates the situation where a negative AP occurs because the MP rebids a lower gas quantity in a later schedule. Compared with Table 13.6, the only change in this example is the decreased bid quantity in schedule 2.

Again, the market outcomes and payments for the first schedule are the same as Table 13.6. However, in the second schedule,

- The MP rebids a lower quantity of gas with no change to the bid price. The gas that was scheduled but is yet to be injected in schedule 1 has to be descheduled because it is no longer available to the market.

- The MP has to buy back 10 GJ of gas from the market (that it sold to the market in the first schedule) and pays an IP of –$30 ($= -10 \times \$3$).

- The MP refunds an AP of –$15 ($= -10 \times (\$5.00 - \$3.50)$) because the constrained-up gas is no longer available. The refund is the same as the initial AP received in the first schedule.

- The MP has to pay back $45 of combined IP and AP for the quantity of gas that it has to buy back from the market.

In this example, the total IPs are $5 and the total APs are zero—that is, the AP received by the MP in the first schedule was fully refunded to the market and not subject to subsequent market price movement. This type of AP clawback algorithm was introduced in April 2012 and is designed so that market participants are neither advantaged nor disadvantaged when market participants reduce their bids to reflect that they no longer have the available gas supply for the market.

Table 13.8   Example of negative AP due to rebidding with reduced quantity

Bid	1	2	Total
Bid price ($/GJ)	5.00	5.00	
Market price ($/GJ)	3.50	3.00	
Bid quantity (GJ)	10	0	
QIS (GJ)	10	0	
Change in CUIQ (GJ)	10	−10	
IP ($)	35.00	−30.00	5.00
AP ($)	15.00	−15.00	0.00
Total IP + AP ($)	50.00	−45.00	5.00

13.2.6.4 Negative AP with no preceding positive APs

The situation shown in Table 13.9 occurs frequently on gas days when the system is not constrained and is most likely in non-winter months. In general, this happens when the scheduled quantity decreases in the later schedules and, at the same time, the market price falls below the MP's bid price.

In the first schedule,

- The market price is 3.50 $/GJ.

- The MP is scheduled to inject 10 GJ of gas at the bid price of 3.50 $/GJ.

- The MP has sold 10 GJ of gas to the market and receives an IP of $35 ($= 10 \times \$3.50$).

- The MP receives an AP of $0 ($= 10 \times (\$3.50 - \$3.50)$).

- The MP receives a total IP and AP of $35.

In the second schedule,

- The market price has fallen to 3.00 $/GJ.

- The MP is scheduled to inject 0 GJ.

- The MP has to buy back 10 GJ of gas from the market (that it sold to the market in the first schedule) and pays an IP of –$30 ($= -10 \times \$3$).

- The MP refunds an AP of –$5 ($= -10 \times (\$3.50 - \$3.00)$) because the constrained-up gas is no longer required.

- The MP has to pay back $35 of IP and AP for the quantity of gas that it has to buy back from the market.

In this example, the total IP is $5 and the total AP is –$5. The total net payment is zero when IP and AP are considered together, and the MP is even. The net payment can be positive or negative (the MP can make a profit or a loss) depending on the difference between the applicable market and bid prices.

Table 13.9   Example of negative AP with no preceding positive AP

Bid	1	2	Total
Bid price ($/GJ)	3.50	3.50	
Market price ($/GJ)	3.50	3.00	
Bid quantity (GJ)	10	10	
QIS (GJ)	10	0	
Change in CUIQ (GJ)	10	−10	
IP ($)	35.00	−30.00	5.00
AP ($)	0.00	−5.00	−5.00
Total IP + AP ($)	35.00	−35.00	0.00

13.3 The AP clawback algorithm

When a market participant is scheduled to inject an amount of gas for the day, and this amount is reduced in a later schedule, the positive APs in the earlier schedules are "clawed back"—that is, they are recovered as negative ancillary payments.

The negative APs will exactly cancel out the earlier positive APs if all of the following conditions are met:

- There is no change in the bid price or quantity.

- There is no change in the market price.

- The quantity of gas scheduled in previous OS is completely scheduled off.

However, if an MP increases its bid prices in subsequent schedules (while the relevant market prices do not change) and is consequently scheduled off or down, the MP could incur a negative AP. This could be much greater than the positive AP it received in the earlier schedules. This is because the

price for each GJ associated with the negative AP (being the difference between the MP's increased bid prices and market prices at the subsequent schedules) is greater than the prices in the previous schedules when positive APs were initially incurred. Negative APs could therefore result in a substantial cost over-recovery by the market.

Accordingly, when a negative AP is calculated, account must be taken of the bid price in the earlier schedules that lead to the positive AP.

The AP clawback algorithm was implemented in May 2008 following the experience in winter 2007 in which some MPs received large negative APs because they rebid their gas injections at a higher price in later schedules (see example in Section 13.2.6.2 "AP clawback type I").

Subsequently, an enhancement to the AP clawback algorithm was introduced in April 2012 to address negative AP arising from reduced bid quantities in later schedules (see example in Section 13.2.6.3 "AP clawback type II"). This can significantly impact on MPs who can no longer offer the initial intended gas supply to the market.

A five-step approach is applied to adjust the initial AP, as described in Section 13.2. The adjustments apply to each bid step in each schedule and for each injection and withdrawal point.

Step 1 — Flag bid steps with the reduced rebid quantity

Identify and flag bid steps associated with the reduced rebid quantity applicable to the enhanced AP clawback algorithm.

Step 2 — Match schedules to determine bid prices

Match schedules where a facility is constrained on (at bid price 1) with subsequent schedules where the constrained-up quantity is reduced (at bid price 2).

Step 3 — Revise negative initial APs due to reduced rebid quantity

Calculate the revised AP for schedules with a negative initial AP due to reduced rebid quantity (the enhanced AP clawback algorithm). If a negative initial AP occurs in bid steps flagged in step 1, the negative AP is recalculated by using the bid price and the market price of the prior schedules where the associated positive AP first occurs. This step ensures the APs are totally clawed back as a result of reduced rebid quantity.

Step 4 — Revise remaining negative initial APs

Calculate the revised AP for schedules with a negative initial AP for bid steps not associated with reduced rebid quantity (the AP clawback algorithm). For all other non-flagged bid steps, the negative AP is recalculated, by using the lesser (or the greater for a withdrawal) of bid price 1 and bid price 2 as the bid price used in calculating the revised AP. This step eliminates the excessive clawback of APs due to rebidding.

Step 5 — Adjust revised APs

Adjust the revised AP by reinstating some of the negative AP removed in step 4 for some schedules. The adjustments in step 4 can result in an increased total (positive) AP compared with the initial AP before the adjustments. This means that MPs who caused the initial positive APs need to pay more uplift charges. Step 5 involves applying a correction to the revised APs for each bid step that were adjusted in step 4 for the relevant schedules. In such cases, the following rules apply:

a. If the total revised AP for the schedule is negative, then no further changes are made.

b. If the total revised AP for the schedule is positive and equals the total initial AP, then no further changes are made.

c. If the total revised AP for the schedule is positive and does not equal the total initial AP and the initial AP for the bid step is negative, then the AP clawback will be reinstated to the bid step either partially or in full. The correction to the bid step AP is based on the change in CUIQ multiplied by an average rate of reinstated AP. The latter is calculated by dividing the total revised AP for the schedule by the greater of the total changes in positive and negative CUIQ for that schedule.

Figure 13-3 illustrates how negative changes in CUIQ are systematically matched with positive change in CUIQ so that the bid prices for paired schedules can be identified and is then used to calculate the revised AP for the relevant bid steps.
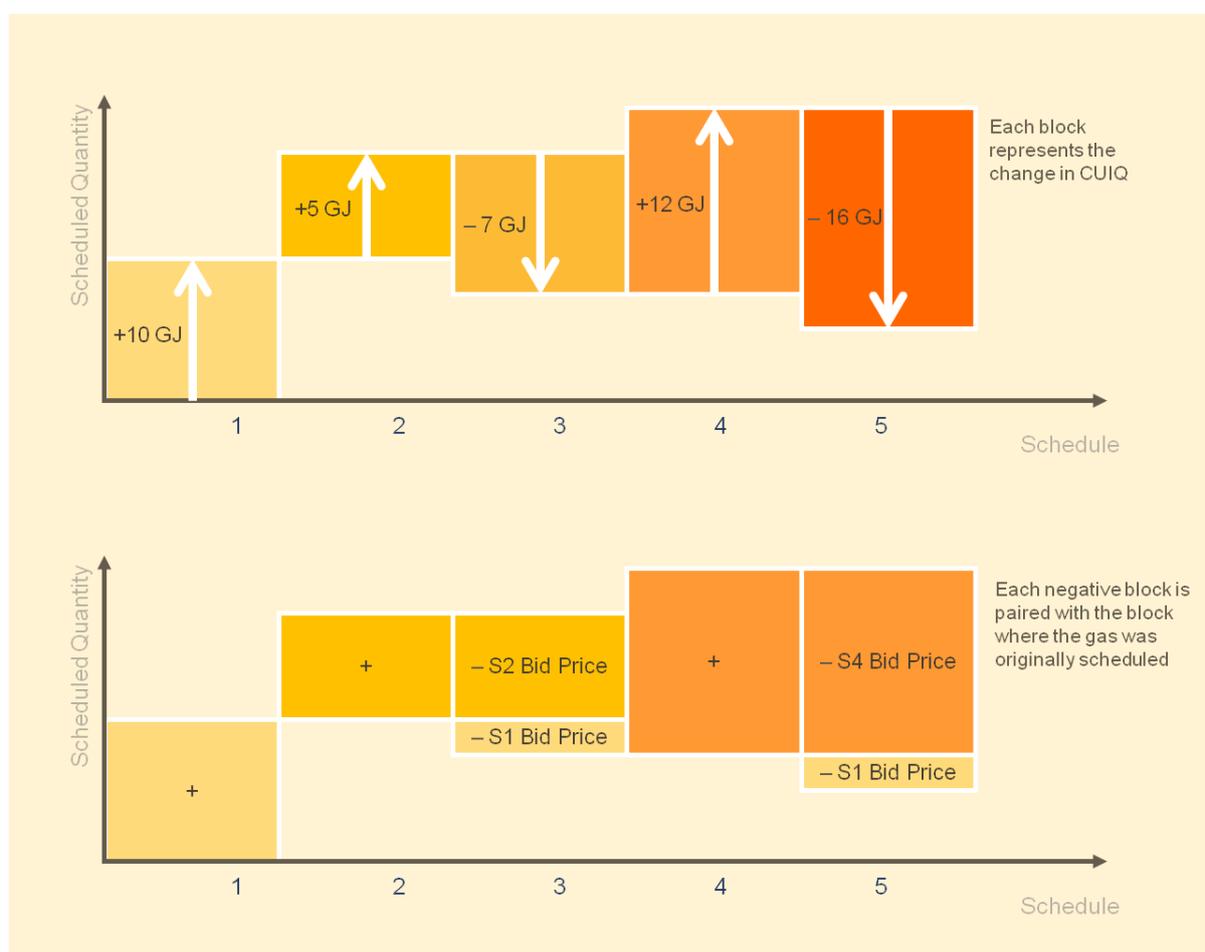
Figure 13-3   Matching bids for clawback pricing

In the top diagram in Figure 13-3, each block represents the change in CUIQ. Schedules 3 and 5 have negative changes in CUIQ. The matching is as follows:

•   –7 GJ in schedule 3 is matched with +5 GJ in schedule 2 and +2 GJ in schedule 1.

•   –16 GJ in schedule 5 is matched with +12 GJ in schedule 4 and +4 GJ in schedule 1.

In calculating the revised AP for schedule 3, the bid prices in the paired schedules (2,3) and (1,3) are used, while the bid prices in the paired schedules (4,5) and (1,5) are used to calculate the revised AP for schedule 5.

13.3.1   An example of AP clawback

Table 13.10 illustrates the AP clawback mechanism. This example assumes that the actual quantity of gas flowed meets the final OS injection so that the AGINO is zero for all schedules. No gas from this injection point is scheduled in the PS and, hence, the MSIQ is zero for all schedules. The CUIQ is therefore equal to the OS quantity.

Table 13.10   Example of AP clawback (steps 1 to 4)

	6 AM	10 AM	2 PM	6 PM	10 PM	Total daily
Bid price ($/GJ)	10.00	20.00	30.00	120.00	120.00	
Market price ($/GJ)	8.00	8.00	7.00	7.00	6.00	
Bid quantity (GJ)	10	10	10	10	1	
OS (GJ)	10	5	3	3	1	
Change in CUIQ (GJ)	10	–5	–2	0	–2	
Initial AP ($)	20.00	–60.00	–46.00	0.00	–228.00	–314.00
Bid price use for revised AP ($/GJ)	10.00	10.00	10.00	120.00	10.00	
Market price used for revised AP ($/GJ)	8.00	8.00	7.00	7.00	8.00	
Revised AP ($)	20.00	–10.00	–6.00	0.00	–4.00	0.00

Referring to the above table:

- The CUIQ for the 6 AM schedule is 10 GJ.

- In the 10 AM schedule, the MP increases its bid price for the same 10 GJ of gas and consequently is scheduled down to 5 GJ and there is no change in the market price.

- In the 2 PM schedule, the MP increases its bid price again and is scheduled down to 3 GJ.

- The MP increases its bid prices again in the 6 PM schedule with no further gas injections scheduled for the remaining scheduling horizon such that the OS quantity remains at 3 GJ in that schedule.

- Lastly, in the 10 PM schedule, due to an unforseen circumstance, the MP decreases its rebid quantity to reflect that it can no longer supply its gas to the market for the remaining scheduling horizon, and the OS is decreased to 1 GJ accordingly (which is the gas already scheduled to flow in the first four scheduling intervals).

Step 1 — Flag bid steps with the reduced rebid quantity

The bid step in the last schedule with the reduced rebid quantity is flagged.

Step 2 — Match schedules to determine bid prices

The change in CUIQ is 10 GJ for the 6 AM schedule and –5 GJ, –2 GJ and –2 GJ for the 10 AM, 2 PM and 10 PM schedules, respectively. These negative changes in CUIQs are paired with the CUIQ in the 6 AM schedule to determine:

- The minimum bid prices of each pair. This is used to calculate the revised AP for unflagged bid steps in step 4.

  In this case (see Figure 13-4), two unflagged pairs are (6 AM, 10 AM) and (6 AM, 2 PM). The paired bid price for both the 10 AM and 2 PM schedules is 10 $/GJ (compared with the bid prices of 20 $/GJ and 30 $/GJ).

- The market price and bid price of the schedule where the positive AP first occurs. This is used to calculate the revised AP for the flagged bid step in step 3.

  In this case (see Figure 13-4), the flagged reduced bid quantity in the 10 PM schedule is paired with the 6 AM schedule, which gives a paired bid price of 10 $/GJ and a paired market price of 8 $/GJ (compared with the 10 PM schedule bid price of 120 $/GJ and market price of 6 $/GJ)
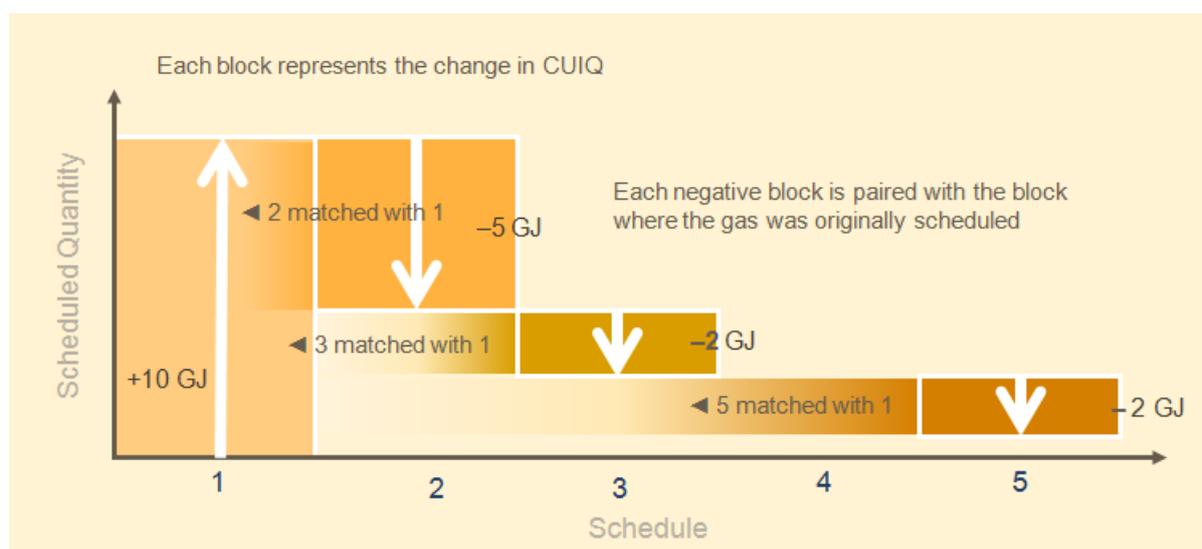
Figure 13-4   Example of matching bids for clawback pricing

Step 3 — Revise negative initial APs due to reduced rebid quantity

Referring to Table 13.10, the revised AP for the 10 PM schedule is –$4, which is calculated by:

10 PM schedule AP clawback

$$= \text{change in constrained quantity}$$
$$\times (\text{modified bid price (bid prices 1 and 5)}$$
$$- \text{modified market price (market prices 1 and 5)})$$
$$= -2 \times (\$10 - \$8) = -\$4$$

Step 4 — Revise remaining negative initial APs

Referring to Table 13.10, the revised APs are –$10 and –$6 for the 10 AM and 2 PM schedules, respectively, which are calculated by:

10 AM schedule AP clawback

$$= \text{change in constrained quantity} \times \text{MAX}(\$0, \text{MIN(bid prices 1 and 2)} - \text{market price})$$
$$= -5 \times \text{MAX}(\$0, \text{MIN}(\$10, \$20) - \$8)$$
$$= -5 \times \text{MAX}(\$0, \$2) = -\$10$$

2 PM schedule AP clawback

$$= \text{change in constrained quantity} \times MAX(\$0, MIN(\text{bid prices } 1 \text{ and } 3) - \text{market price})$$
$$= -2 \times MAX(\$0, MIN(\$10, \$30) - \$7)$$
$$= -2 \times MAX(\$0, \$3) = -\$6$$

Step 5 — Adjust revised APs

Following on from the example in Table 13.10 above, further adjustments need to be applied to the 10 AM schedule to reinstate some of the negative AP removed (as described in step 5 in Section 13.3). This is illustrated in Table 13.11.

Table 13.11   Example of AP clawback (step 5)

	A	B		
10 AM schedule	**Bid 1**	**Bid 1**	**Bid 2**	**Total**
Change in CUIQ (GJ)	–5	21	–5	
Initial AP ($)	–60.00	170.00	–10.00	100.00
Revised AP (after clawback step 2 and 4)	–10.00	170.00	–5.00	155.00
AP rate ($/GJ)	7.38		7.38	
Reinstated negative AP	–36.90	0.00	–36.90	
AP	–46.90	170.00	–10.00	113.10

Referring to the above table, market participant A has one bid step for the 10 AM schedule—the data of this bid step is taken from Table 13.10. And market participant B has two bid steps.

The revised AP for A's bid step 1 is reduced to –$10 from –$60 after adjustments in clawback steps 2 and 4. There is no change to the initial AP for B's bid step 1. The revised AP for B's bid step 2 is also reduced, to –$5 from –$10. The revised AP for the schedule has thus increased from $100 to $155. This means that the market funds $55 more AP than is required. And so, some negative AP will be reinstated.

The adjustment for A's bid step 1 AP is calculated by:

- The total negative CUIQ is –10 GJ and the total positive CUIQ is 21 GJ.

- The AP rate is equal to the total revised AP divided by the greater of the total positive and negative CUIQ $(= \$155/MAX(10 \text{ GJ}, 21 \text{ GJ}) = 7.38 \text{ \$/GJ})$.

- The reinstated AP equals the AP rate multiplied by the change in CUIQ $(= 7.38 \text{ \$/GJ} \times -5 \text{ GJ} = -\$36.90)$.

- The reinstated negative AP is added back to the revised negative AP in bid step 1. The final AP is therefore –$46.9 $(= MAX(-\$60.00, -\$36.90 - \$10.00))$, which is of the greater of the AP values before and after the corrections.

- The adjustment for B's bid step 2 is done the same way. The reinstated AP equals the AP rate multiplied by the change in CUIQ $(= 7.38 \text{ \$/GJ} \times -5 \text{ GJ} = -\$36.90)$.

- The reinstated negative AP is added back to the revised negative AP in bid step 2. The final AP is therefore –$10.0 $(= MAX(-\$10.00, -\$36.90 - \$5.00))$, which is of the greater of the AP values before and after the corrections.

- The total AP for the schedule after adjustment for clawback is then $113.10 $(= -\$46.90 + \$170.00 - \$10.00)$

13.4   The AP flip-flop algorithm

Winter 2007 (the first winter of the DWGM) saw a number of gas days with large positive APs in the early schedules, which were followed with large negative APs in the subsequent schedules. In some cases, the negative APs were large enough to completely cancel the large positive APs. When a positive AP occurs as a result of congestion in the transmission system, MPs who cause it are required to fund the positive AP via positive uplift payments to the market. However, when system congestion is relieved, resulting in negative APs, money is returned to MPs via negative uplift payments. It is possible that MPs who cause system congestion in the early schedules (and pay uplift charges to the market) are not those who receive money from the market in the subsequent schedules when the system congestion is resolved. Hence, AP flip-flops can create an issue of equity in the market.

A mechanism was introduced to minimise the swings in total market APs from schedule to schedule while not changing the total APs paid to each MP over the gas day. To the extent possible, the flip-flop mechanism systematically cancels out negative APs with related positive APs to minimise the fluctuations in uplift amounts.

The AP flip-flop algorithm applies to total APs for each schedule—sum of total injection and withdrawal APs—which have already been adjusted for AP clawback, and determines the total uplift payments to be allocated to the responsible MPs. The AP flip-flop adjustments involve the following steps.

Step 1 — Assign groupings to consecutive schedules of AP with the same sign

The injection and withdrawal APs for all MPs (after AP clawback adjustment) are summed for each schedule (TAP). Consecutive schedules of revised APs with the same sign are assigned to the same group. For the purpose of assigning groupings, schedules with 0 APs are grouped with those with positive APs.

Step 2 — Cancel negative revised APs with positive revised APs in preceding schedules

Total negative APs are used to cancel as much of the positive APs as possible. Negative APs can only be used to cancel positive APs in the preceding schedules. Depending on the magnitude of the positive and negative APs in each combination, the total adjusted APs (resulting from cancellations of positive APs with negative APs) can be zero, positive or negative (TAAP).

Step 3 — Apportion total adjusted APs

This step involves apportioning the total adjusted AP (obtained in step 2) in each group to each schedule in that group according to each schedule's share of the total adjusted AP, from which the total uplift payments are derived (TUP).

13.4.1   An example of AP flip-flop

Table 13.12 shows how the AP flip-flop method is applied to smooth out the volatility of APs in related schedules while still allocating costs to cause. Referring to the table:

- The revised APs are assumed to be $900, –$400, –$800, $200 and $0.

- Based on the sign of the APs, the assigned groupings are 1, 2, 2, 3 and 3 for schedules 1 to 5 respectively.

- The negative APs in the 10 AM and 2 PM schedules can be used to reduce the positive AP in the 6 AM schedule, and there are no possible cancellations of APs for the 6 PM and 10 PM schedules. This reduces the total APs for the 10 AM and 2 PM schedules to zero and results in a negative total adjusted AP of –$300 in the 2 PM schedule.

- The final AP for the 10 AM schedule is –$100 and –$200 for the 2 PM schedule after apportioning the total adjusted AP.

- The net total AP for the gas day remains unchanged at –$100.

Table 13.12   Example of AP flip-flop

	6 AM	10 AM	2 PM	6 PM	10 PM	Total daily
Total revised AP (adjusted for AP clawback) (TAP)	$900	–$400	–$800	$200	$0	–$100
AP grouping (step 1)	1	2	2	3	3	
Total adjusted AP (adjusted for AP flip-flop step 2) (TAAP)	0	0	–$300	$200	$0	–$100
Final AP (adjusted for AP flip-flop step 3) (TUP)	$0	–$100	–$200	$200	$0	–$100

14 Uplift hedge

An uplift hedge (UH) is the amount of AMDQ that an MP nominates to use as a hedge against congestion uplift. The nominated quantity of authorised AMDQ or AMDQ credit must be supported by scheduled injections from the nominated source of gas supply. The scheduled injection can be used either to support an uplift hedge or to qualify for an AP but not both at the same time.

The UH is converted to interval quantities for each scheduling interval—the authorised maximum interval quantity (AMIQ)—using the MP's nominated AMIQ profile.

For more information, refer to *Uplift Payment Procedures* [22], *Uplift Payment Functional Design* [23], and *National Gas Rules* [44].

In this chapter:

- The uplift hedge process

- A worked example of uplift hedge calculation

- Authorised maximum interval quantity

14.1 The uplift hedge process

For the purpose of calculating UH, injection points are grouped into close proximity injection points (CPP). For example, injections under various contracts at VicHub and Longford are considered to be injected from the Longford CPP. Similarly, injections from various sources at Iona—for example, SEA Gas and Iona underground storage—are all deemed to be from the Iona CPP.

Figure 14-1 outlines the process for calculating uplift hedge and AMIQ.

See Appendix 4 for a detailed diagrammatic representation of the AMIQ calculation process.

The calculations involve the following steps.

Step 1 — Calculate load diversity

For each injecting MP, calculate the diversified site (Tariff D) authorised MDQ and AMDQ credit at each CPP. Because not all customer demand peaks at the same time, a load diversity factor is calculated for each Tariff D site to take into account the diversity of the site demand pattern compared to the total system. The AMDQ load diversity factor for a site is the ratio between the average authorised gas usage on selected system peak days and the AMDQ at that site.

Note. Tariff D authorised MDQ apply to the Longford CPP, whereas AMDQ credits apply to non-Longford CPP.
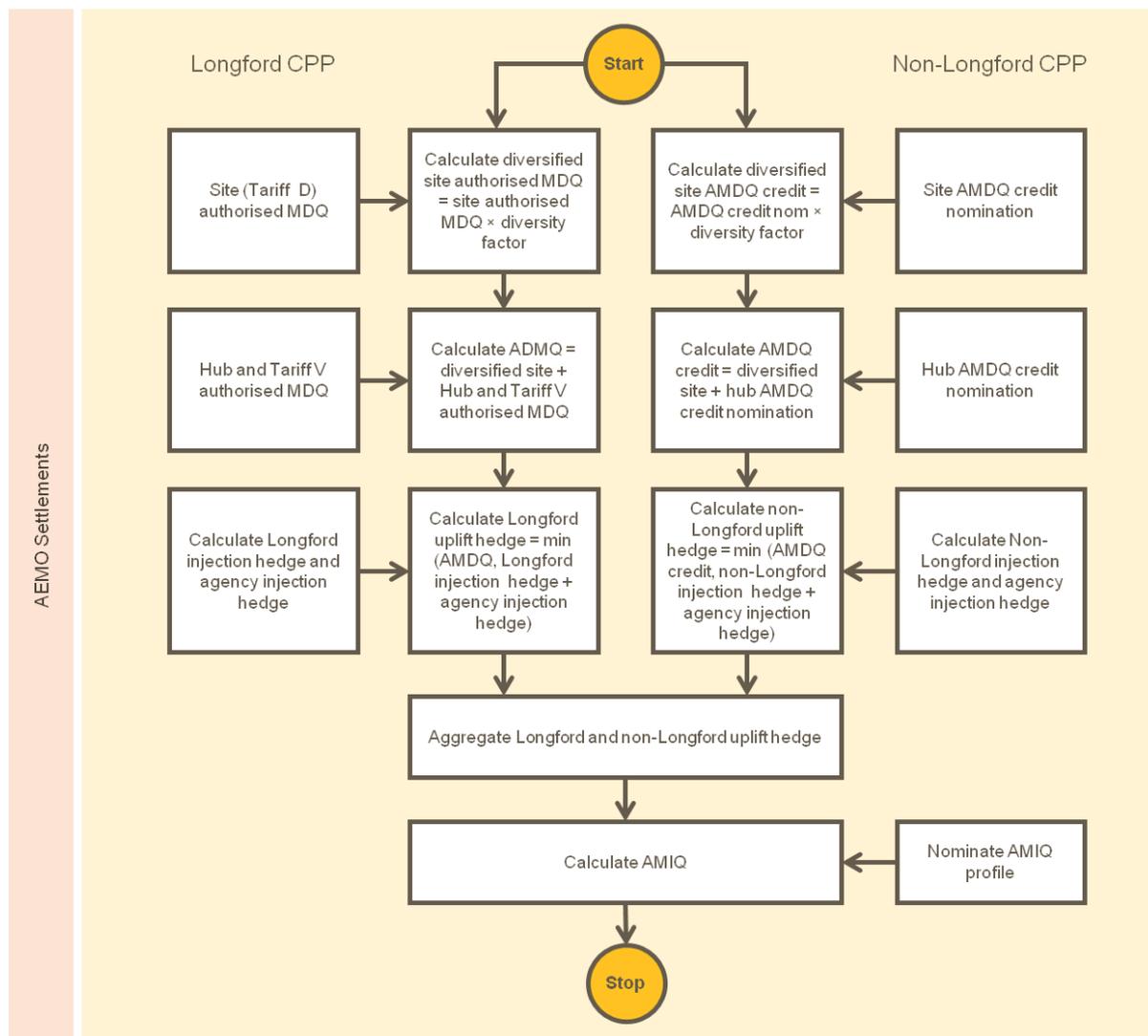
Figure 14-1   Uplift hedge and AMIQ determination process

Step 2 — Calculate AMDQ

An MP's Longford AMDQ is equal to the MP's total diversified Tariff D authorised MDQ, plus the MP's allocated share of Tariff V authorised MDQ, plus the MP's authorised MDQ at the reference hub, if any.

An MP's non-Longford AMDQ is equal to the MP's total diversified AMDQ credit, plus the MP's AMDQ credit nominations assigned to the reference hub, if any.

Step 3 — Calculate IH and AIH

Injection hedge (IH) and agency injection hedge (AIH) are calculated from injection hedge and agency hedge nominations submitted by MPs via WebExchanger (see sections 7.5.3 and 7.5.4). These nominations need to be supported by scheduled injections from the relevant CPPs.

In determining IH and AIH, priority is given to the MP's own IH nomination and, if there are sufficient gas injections to support the AIH nominations, MPs are allocated a share of the remaining scheduled injections on either a preferred or pro rata basis according to the information provided by the AIH provider.

An MP's IH is the lesser of its injection hedge nomination and the MP's scheduled injection quantity at the given CPP.

An MP's (recipient) AIH is part or all of the minimum of an AIH provider's agency injection hedge nomination, and that provider's scheduled injection quantity less that provider's injection hedge at the given CPP.

Step 4 — Calculate UH at each CPP

For the Longford CPP, the uplift hedge is equal to the lesser of the MP's authorised MDQ and the sum of its Longford CPP IH and AIH.

For each non-Longford CPP, the uplift hedge is equal to the lesser of the MP's AMDQ credit and the sum of its non-Longford IH and AIH.

Step 5 — Calculate total UH

Finally, the MP's total uplift hedge equals its Longford CPP uplift hedge plus its total non-Longford CPP uplift hedge.

14.2 A worked example of uplift hedge calculation

The example in Table 14.1 shows how uplift hedge is calculated with two MPs injecting for themselves and for each other. In this example, the following assumptions have been made:

Market participant A

- A has 80 GJ of Longford diversified authorised MDQ, 70 GJ of allocated Tariff V block authorised MDQ and 95 GJ of diversified AMDQ credit.

- A is scheduled to inject 126 GJ from Longford and 35 GJ from a non-Longford CPP.

- A has nominated to use 120 GJ and 10 GJ of the Longford scheduled injections as Longford IH and Longford AIH, and 10 GJ and 10 GJ of non-Longford scheduled injections as non-Longford IH and non-Longford AIH.

- All IH nominations as well as non-Longford AIH nomination are approved because there are sufficient scheduled injections to support them, but only 6 GJ of Longford AIH nomination is approved due to insufficient injection support.

- A receives the approved AIHs from B, and B receives the approved AIHs from A.

- A's total uplift hedge is therefore 135 GJ, which is the sum of 125 GJ and 10 GJ from Longford and non-Longford CPP respectively.

Market participant B

- B has 50 GJ of Longford diversified authorised MDQ, 72.5 GJ of allocated Tariff V block authorised MDQ and 80 GJ of diversified AMDQ credit.

- B is scheduled to inject 110 GJ from Longford and 7.8 GJ from a non-Longford CPP.

- B has nominated to use 100 GJ and 5 GJ of the Longford scheduled injections as Longford IH and Longford AIH, and 10 GJ and 5 GJ of non-Longford scheduled injections as non-Longford IH and AIH.

- All Longford nominations are approved because there are sufficient scheduled injections to support them, but there are insufficient scheduled injections to support non-Longford nominations, which resulted in 7.8 GJ and 0 GJ of IH and AIH respectively.

- B receives the approved AIHs from A, and A receives the approved AIHs from B.

- The total uplift hedge is therefore 123.8 GJ, which is the sum of 106 GJ and 17.8 GJ from Longford and non-Longford CPP respectively.

Table 14.1   Uplift hedge calculation

			A		B	
		All measurements in GJ	Longford CPP	Non-Longford CPP	Longford CPP	Non-Longford CPP
Calculate AMDQ	1.	Diversified authorised MDQ or AMDQ credit (GJ)	80.0	95.0	50.0	80.0
	2.	Tariff V authorised MDQ share	70.0		72.5	
	3.	Total AMDQ = 1 + 2	150.0	95.0	122.5	80.0
Calculate IH and IAH	4.	OS injection	126.0	35.0	110.0	7.8
	5.	Injection hedge nomination	120.0	10.0	100.0	10.0
	6.	Injection hedge = MIN (4, 5)	120.0	10.0	100.0	7.8
	7.	Agency injection hedge nomination (preferred basis)	10.0	10.0	5.0	5.0
	8.	Agency injection hedge provided = MIN (7, 4 − 6)	6.0	10.0	5.0	0.0
	9.	Agency injection hedge received	5.0	0.0	6.0	10.0
Calculate UH	10.	Uplift hedge = MIN (3,6 + 9)	125.0	10.0	106.0	17.8
	11.	Total uplift hedge		135.0		123.8

14.3 Authorised maximum interval quantity (AMIQ)

MPs who intend to use their uplift hedges against congestion uplift assign a percentage of their total uplift hedge as authorised maximum interval quantity (AMIQ) for each scheduling interval. The AMIQ% profile is submitted by MPs at the BOD schedule and can be resubmitted for reschedules, but only the AMIQ% profile for the final (10 PM) schedule is used to calculate AMIQ. AMIQ% profiles are subject to a set of maximum limits that can be assigned for each scheduling interval. These limits are based on a winter peak-day demand profile defined in AEMO's system planning criteria. If the submitted profile for the gas day is outside the allowable limits, they will be rejected. A warning

message is displayed by WebExchanger when there are errors in the submitted profile; MPs can then choose to resubmit the information.

Table 14.2 summarises the upper % limits on an MP's submitted AMIQ% profiles. AMIQ% must be between zero and the following upper limits:

- 25.8% for scheduling intervals between 6 PM and 10 PM

- 41.8% for scheduling intervals between 2 PM and 10 PM

- 78.4% for scheduling intervals between 6 AM and 10 PM

Table 14.2   AMIQ% profile upper limits

6 AM – 10 AM	10 AM – 2 PM	2 PM – 6 PM	6 PM – 10 PM	10 PM – 6 AM
100%				
78.4%				42.6%
42.6%		41.8%		42.6%
25.8%	25.8%	25.8%	25.8%	42.6%

The AMIQ for each scheduling interval is calculated by apportioning the total uplift hedge in accordance with the MP's nominated AMIQ% profile as shown in step 6 of the uplift hedge and AMIQ process (follows step 5 in Section 14.1).

Step 6 — Calculate AMIQ

The AMIQ is calculated by applying the MP's nominated AMIQ% profile to the sum of its Longford and non-Longford uplift hedges.

An example of AMIQ calculations

Table 14.3 illustrates how AMIQ is derived from uplift hedge and the nominated AMIQ% profile from the MP. In this example, the total uplift hedge supported by scheduled injections is 135 GJ. This is apportioned to each scheduling interval according to the MP's submitted AMIQ% profile, which complies with the maximum AMIQ% limits shown in Table 14.2.

Table 14.3   Calculation of AMIQ for uplift hedge

Schedule	AMIQ% profile	AMIQ (GJ)
6 AM – 10 AM	18%	24.3
10 AM – 2 PM	16%	21.6
2 PM – 6 PM	15%	20.3
6 PM – 10 PM	25%	33.8
10 PM – 6 AM	26%	35.1
Total	100%	135.0

15 Uplift payments

An uplift payment (UP) is normally charged to the MP whose actions caused the associated ancillary payment (AP). Hence, the total UPs paid by MPs should equal the total APs paid to MPs. In special circumstances, the Declared Transmission System Service Provider (DTSSP) pays a component of the UP. This chapter explains the concepts behind the various types of uplift payments and how they are calculated.

For more information, refer to *Uplift Payment Procedures* [22], *Uplift Payment Functional Design* [23], and *National Gas Rules* [44].

In this chapter:

- Overview of uplift payments

- Demand forecast overrides and effective demand forecasts

- DTSSP congestion uplift

- Calculations of market participant's uplift quantity

- Uplift payments

15.1 Overview of uplift payments

There are four categories of uplift payments:

- **Surprise.** Surprise UP is charged to MPs who deviate from their scheduled injections or controllable/ uncontrollable withdrawals in the previous schedule, or change their demand forecasts in the following schedule.

- **Congestion.** Congestion UP is charged to MPs who cause system congestion because their scheduled withdrawals exceed their AMIQ uplift hedge (AMIQ).

- **DTSSP congestion.** DTSSP congestion UP is allocated to the DTSSP where it can be determined that the DTSSP has contributed to congestion by not making available the relevant plant and the associated pipeline capacity as required under the service envelope agreement (SEA).

- **Common.** Common UP includes uplifts that cannot be allocated to any MPs, for example costs associated with AEMO's excessive demand forecast overrides. These costs are apportioned to MPs who withdraw gas on the relevant gas day.

Figure 15-1 shows the process for calculating uplift payments.
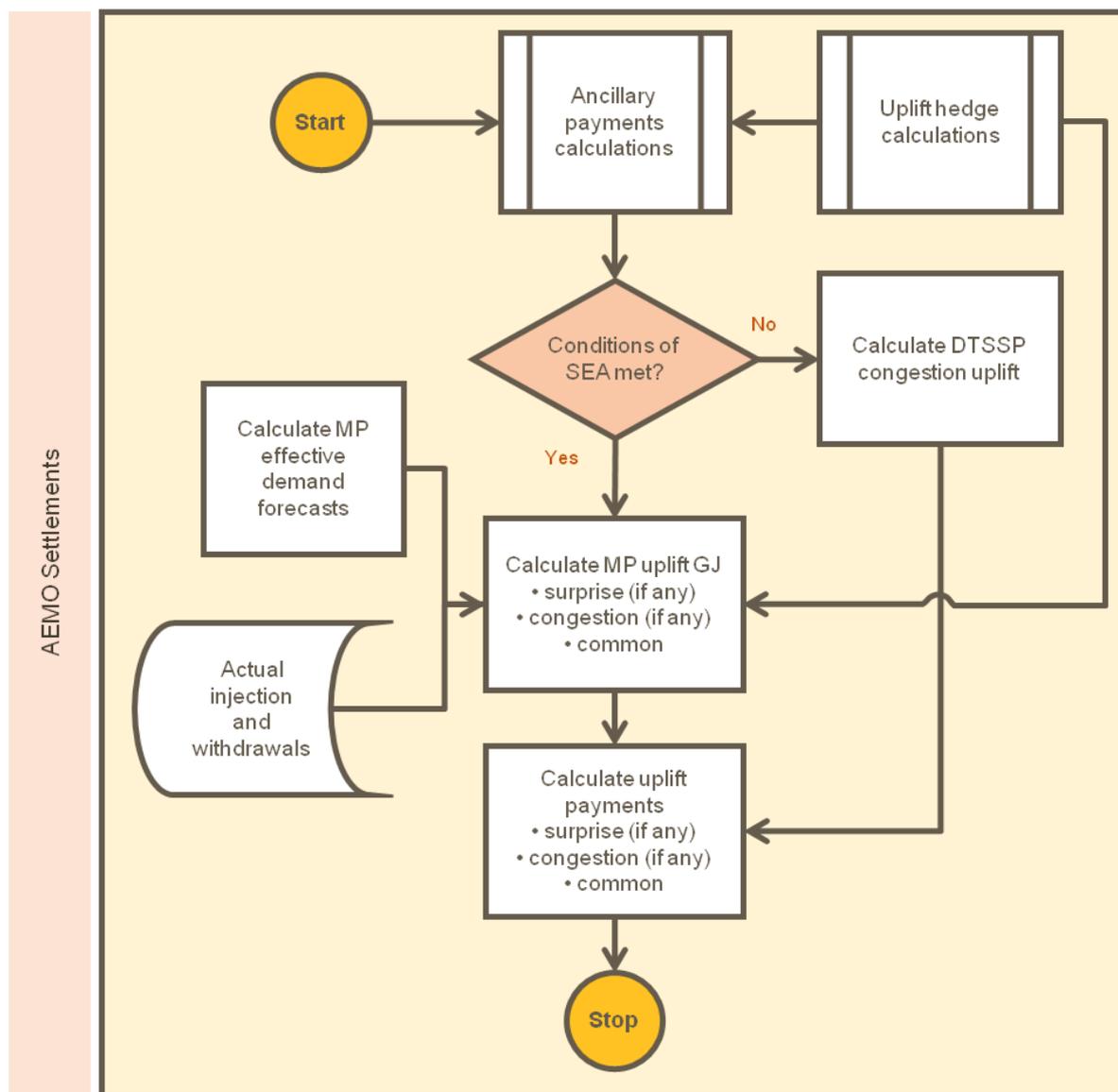
Figure 15-1   Calculation of uplift payments

The key input data to these calculations include:

- Ancillary payments (see Chapter 13)

- Authorised maximum interval quantity (AMIQ) (see Section 14.3)

- MP's effective demand forecasts (see Section 15.2).

15.2   Demand forecast overrides and effective demand forecasts

MPs with uncontrollable loads must submit hourly forecasts of these loads to AEMO. AEMO compares the aggregated uncontrollable demand forecasts from all MPs with its own demand forecast for each hour of the gas day. AEMO must intervene if it determines that the differences between the two sets of forecasts are too large when compared with set thresholds. If this occurs, AEMO applies hourly demand overrides, which might be positive or negative. This adjusts each MP's

hourly demand forecasts by the quantity needed to bring the MP's demand forecast within a tolerable difference. An MP's adjusted demand forecast is called an effective demand forecast.

Effective demand forecasts are only used for calculating congestion and surprise uplift quantities and do not affect their deviation and imbalance quantities and payments.

AEMO will only adjust MPs' demand forecasts for a given hour if the override for that hour is positive and the sum of the hourly demand overrides within that scheduling interval is also positive.

AEMO follows the procedures set out in *Demand Override Methodology* [9] when applying overrides to MPs demand forecasts.

15.2.1 Calculating AEMO's adjusted hourly demand forecast overrides

Table 15.1 shows how AEMO's demand forecast overrides are adjusted to produce MPs' effective demand forecasts. This particular example is for the 6 AM – 10 AM scheduling interval. Referring to the table:

- AEMO's hourly demand forecasts exceed the aggregated MPs' demand forecasts for each hour between 7 AM and 10 AM such that demand forecast overrides are required for these hours (column A). The total demand forecast deviation (the demand forecast override) for the entire scheduling interval is +3 GJ.

- MPs' demand forecasts for the first hour are not adjusted because they are higher than AEMO's forecast. Hence, the demand forecast override for this hour is zero.

- The total demand forecast override is 3 GJ for the scheduling interval. This is apportioned to each hour ($A \times B$) with a positive demand forecast difference ($A > 0$) in column C.

Table 15.1   Adjusted demand forecast overrides

Scheduling interval 6 AM – 10 AM Hour	Hourly demand forecast deviation GJ	% of positive demand forecast override	Hourly demand forecast override GJ
	A	B	$C = A \times B$
6 AM – 7AM	−1.0	0%	0.0
7AM – 8AM	1.0	25%	0.75
8AM – 9AM	2.0	50%	1.50
9AM – 10 AM	1.0	25%	0.75
Total	3.0	100%	3.0

15.2.2 Calculating MPs' effective demand forecasts

AEMO's hourly demand forecast overrides are allocated to each MP's hourly demand forecasts as effective demand forecasts. These are used for determining congestion and surprise quantities in proportion to their share of the total demand forecast difference for that hour.

Referring to Table 15.2, for the 6 AM – 10 AM scheduling interval, columns A and B show an MP's hourly forecast and actual demand. The MP's demand forecast deviation is calculated in column $C = \mathrm{MAX}\,(0, B - A)$. The total demand forecast difference is shown in column D, and this MP's share of the total is calculated in column $E = C / D$. AEMO's hourly demand forecast override is shown in column F (calculated in Table 15.1). The adjustment to the MP's hourly forecast is then the lesser of

the MP's positive deviation in column C and its share of the demand forecast override ($E \times F$). Finally, the effective demand forecast in column G is calculated by adding the adjustment to the MP's forecast—that is, $G = A + \text{MIN}(C, E \times F)$.

Table 15.2   Calculation of an MP's effective demand forecast

Scheduling interval hour	MP's demand forecast	MP's actual uncontrollable withdrawal	MP's demand forecast deviation	Total demand forecast deviation	MP's share of total demand forecast deviation	AEMO adjusted demand forecast override	Effective demand forecast
	GJ	GJ	GJ	GJ	%	GJ	GJ
	A	B	C	D	E	F	G
6 AM – 7AM	10.0	10.3	0.3	0.3	100%	0.0	10.0
7AM – 8AM	8.0	7.5	0.0	0.8	0%	0.75	8.0
8AM – 9AM	7.0	8.2	1.2	2.0	60%	1.50	7.9
9AM – 10 AM	6.0	6.4	0.4	0.5	80%	0.75	6.4
Total	31.0	32.4				3.0	32.3

Only positive deviation quantities are shown in column C.

Looking at the calculations hour-by-hour in the above table:

6 AM to 7 AM

The MP exceeds its forecast and is in fact responsible for all of the deviation for that hour. However, because no demand forecast override applies to this hour, there is no adjustment to the MP's forecast.

7 AM to 8 AM

The MP's deviation is negative and so this MP cannot be allocated any share of the positive demand forecast override. The total AEMO demand forecast override is 0.75 GJ and is allocated to other MPs who have (positive) deviations. If no MPs deviate positively from their demand forecasts, the unallocated AEMO demand forecast overrides will be included in the common uplift quantities.

8 AM to 9 AM

The MP's deviation is positive. The demand forecasts is adjusted up by 0.9 GJ, which is the lesser of the MP's positive deviation and its share of the aggregate (positive) deviations.

8 AM to 10 AM

The MP's deviation is positive. The demand forecasts is adjusted up by 0.4 GJ, which is the lesser of the MP's positive deviation and its share of the aggregate (positive) deviations.

Interval total

The effective demand forecast for the MP for this scheduling interval is 32.3 GJ, which is slightly lower than its actual demand of 32.4 GJ.

15.3 DTSSP congestion uplift

DTSSP congestion uplift is allocated to the DTSSP for any shortfall in system capacity due to a breach of the Service Envelope Agreement (SEA). For example, this could be due to additional congestion resulting from an unplanned outage of a critical plant where the outage can be attributed to lack of maintenance of the plant in accordance with the SEA.

For the purpose of calculating DTSSP congestion uplift, a shortfall in system capacity is treated as an AMIQ exceedance caused by the DTSSP. The method for calculating an MP's congestion uplift is also used to allocate DTSSP congestion uplift (see Section 15.4.2).

The maximum limit on DTSSP congestion uplift is specified in the Service Envelope Agreement. If these limits are exceeded, the unallocated DTSSP congestion uplift beyond the limits will be added to the relevant common uplift and allocated to all MPs (see Section 15.4.3).

15.4 Calculations of market participant's uplift quantity

The total AP in each schedule is allocated to surprise, congestion, and common uplift based on the quantities determined for each of these categories. This section explains the methods used for calculating these quantities, with worked examples.

15.4.1 Surprise uplift quantity

An MP is liable for surprise uplift if either or both of the following conditions are true:

- The MP deviates from its scheduled quantities (injections and withdrawals) in the previous scheduling interval.

- The MP revises its demand forecasts or scheduled controllable withdrawals in the current schedule.

For the first schedule of the gas day, the surprise uplift quantity is calculated from deviation quantities for the 10 PM – 6 AM scheduling interval of the previous gas day, as follows:

Where,

> s is the schedule, where $s=1$ is the 6 AM schedule
> i is the scheduling interval, where $i=0$ is the last scheduling interval of the previous day and $i=1$ is the current-day 6 AM to 10 AM scheduling interval
> QUS_s is the surprise uplift quantity in schedule s in GJ
> EDF_s is the effective demand forecast in schedule s in GJ
> $EDF(i)$ is the effective demand forecast in scheduling interval i in GJ
> $QCWS_s$ is the scheduled controllable withdrawal quantity in schedule s in GJ
> $QCWS(i)$ is the scheduled controllable withdrawal quantity in schedule i in GJ
> $QUWA(i)$ is the actual uncontrollable withdrawal in scheduling interval i in GJ
> $QCWA(i)$ is the actual controllable withdrawal quantity in scheduling interval i in GJ
> $QIA(i)$ is the actual injection quantity in scheduling interval i in GJ
> $QIS(i)$ is the scheduled injection quantity in scheduling interval i in GJ

The surprise uplift quantity in the first schedule ($s=1$) for an MP is calculated by:

$$QUS_{s=1} = (QUWA(0) - EDF(0)) + (QCWA(0) - QCWS(0)) - (QIA(0) - QIS(0)) \dotfill (15)$$

And the surprise uplift quantity for subsequent schedules ($s>1$) for an MP is calculated by:

$$QUS_{s>1} = (QUWA(i-1) - EDF(i-1))_{i=s} + (QCWA(i-1) - QCWS(i-1))_{i=s}$$
$$-(QIA(i-1) - QIS(i-1))_{i=s} + (EDF_s - EDF_{s-1}) + (QCWS_s - QCWS_{s-1}) \dotfill (16)$$

Surprise uplift quantities can be positive or negative. Positive and negative uplift quantities are associated with positive and negative AP allocations, respectively.

An example of calculations of surprise uplift quantities

Table 15.3 shows calculations of surprise UP quantity (shown in column C). Injection deviations (column A) are those calculated previously in Table 11.2 for MP B. Column B shows deviations in effective demand forecasts and controllable withdrawals and changes in demand forecast and controllable withdrawals between schedules, which are calculated in Table 15.4. Columns D and E show the calculated (positive and negative) surprise uplift quantities.

Table 15.3   Calculation of surprise uplift quantity

Schedule	Injection deviations GJ	Withdrawal deviations + change in forecasts GJ	Surprise uplift GJ	Positive surprise uplift GJ	Negative surprise uplift GJ
	A	B	$C = B - A$	D	E
1	0	1	1	1.0	0.0
2	3	–7.3	–10.3	0.0	–10.3
3	–5	0	5	5.0	0.0
4	–4	–1	3	3.0	0.0
5	1	–1	–2	0.0	–2.0
	From Table 11.2	From Table 15.4			

Table 15.4   Calculation of withdrawal deviations and change in demand forecasts

Scheduling interval (i)	Actual with-drawal	Effective demand forecasts by schedule (s)						Surprise uplift quantity by schedule (s)				
		0	1	2	3	4	5	1	2	3	4	5
0	30.0	29.0						1.0				
1	28.0		32.3						–4.3			
2	23.0		25.0	24.0					–1.0	–1.0		
3	24.0		26.0	25.0	25.0				–1.0	0.0	–1.0	
4	31.0		31.0	30.0	31.0	31.0			–1.0	1.0	0.0	0.0
5	29.0		29.0	29.0	29.0	29.0	28.0		0.0	0.0	0.0	–1.0
							Total	1.0	–7.3	0.0	–1.0	–1.0
							See equation	15	16	16	16	16

In Table 15.4, the values shown in blue are the differences between actual uncontrollable withdrawal quantities and effective demand forecasts for the applicable scheduling interval in equations 15 and 16. And those in red are the breakdown of the calculated changes in effective demand forecasts between the current and previous schedules in equations 16 by scheduling intervals.

For the 6 AM schedule (s=1), the surprise uplift quantity associated with uncontrollable withdrawals is 1 GJ and is equal to the difference between the actual demand (30 GJ) and the effective demand forecast (29 GJ) for the 10 PM – 6 AM scheduling interval of the previous gas day (i=0). Because this is the first schedule of the gas day, there are no changes in demand forecasts.

For the 10 AM schedule (s=2), the surprise uplift quantity associated with uncontrollable withdrawals is –7.3 GJ. This is the sum of –4.3 GJ (= $28\,GJ - 32.3\,GJ$) due to the actual withdrawal deviating from the effective demand forecasts for the 6 AM – 10 AM scheduling interval, and –3 GJ ($= -1\,GJ - 1\,GJ - 1\,GJ + 0\,GJ$). This equals the sum of the downward revisions to the demand forecasts for the remaining four scheduling intervals after 10 AM, which is the change in effective demand forecasts between the 6 AM schedule and the 10 AM schedule.

The surprise uplift quantities for the 2 PM, 6 PM and 10 PM schedules are calculated the same way.

Table 15.5 shows the positive and negative surprise uplift quantities for MP B and the total quantities for all MPs—there are two MPs (MP A and MP B) in this example. This data will be used for calculating surprise uplift payments in Section 15.5.

Table 15.5   Positive and negative surprise uplift quantities

Schedule (s)	MP B		Total all MPs	
	Positive Surprise GJ	Negative Surprise GJ	Positive Surprise GJ	Negative Surprise GJ
1	1.0	0.0	1.0	0.0
2	0.0	−10.3	1.0	−10.3
3	5.0	0.0	5.0	-1.0
4	3.0	0.0	3.0	-1.0
5	0.0	-2.0	0.0	-3.0

15.4.2   Congestion uplift quantity

If an MP is scheduled to withdraw a quantity of gas that exceeds its AMIQ for that scheduling interval, and the system is congested resulting in a positive AP, then it must pay a congestion uplift charge (see Section 14.3 for more details about AMIQ).

Where,

> i is the scheduling interval, where $i=1$ is the 6 AM to 10 AM scheduling interval
> $EDF(i)$ is the effective demand forecast in interval i in GJ
> $QWS(i)$ is the scheduled withdrawal quantity in interval i in GJ
> $AMIQ(i)$ is the authorised maximum interval quantity in interval i in GJ

AMIQ exceedance or congestion uplift quantity (QUC) for scheduling interval i is calculated by:

$$QUC(i) = MAX(0, EDF(i) + QWS(i) - AMIQ(i)) \dotfill (17)$$

The congestion uplift quantity for the 6 AM schedule ($s=1$) is the sum of the congestion uplift quantities for all the scheduling intervals included in that schedule.

$$QUC_{s=1} = \sum_i QUC(i) \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots(18)$$

The congestion uplift quantity for the subsequent schedules ($s>1$) is the sum of the change in congestion uplift quantities between successive schedules.

$$QUC_{s>1} = \sum_{i \geq s}(QUC(i) - QUC(i-1)) \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots(19)$$

Table 15.6 shows how congestion uplift quantities are calculated for a gas day using the AMIQ information shown in Table 14.3, the effective demand forecasts, and scheduled controllable withdrawals (assumed 0 GJ in this case). The congestion uplift quantities are 17.2 and –2.0 GJ for the 6 AM ($s=1$) and 10 AM ($s=2$) schedules respectively, and 0 GJ for all subsequent schedules.

Table 15.6   Calculation of congestion uplift quantity (AMIQ exceedance)

	AMIQ	Effective demand forecasts and scheduled controllable withdrawals					Congestion uplift quantity (AMIQ exceedance)					Change in congestion uplift quantity			
	GJ	GJ					GJ					GJ			
i		1	2	3	4	5	1	2	3	4	5	2	3	4	5
1	24.3	32.3					8.0					NA			
2	21.6	25.0	24.0				3.4	2.4				–1.0			
3	20.3	26.0	25.0	25.0			5.8	4.8	4.8			–1.0	0.0		
4	33.8	31.0	30.0	31.0	31.0		0.0	0.0	0.0	0.0		0.0	0.0	0.0	
5	35.1	29.0	29.0	29.0	29.0	28.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total schedule							17.2	7.2	4.8	0.0	0.0	–2.0	0.0	0.0	0.0
See equation							18	17	17	17	17	19	19	19	19

Note that the values in each row are for the scheduling intervals i=1 to 5

Congestion uplift quantities can be positive or negative. Positive quantities are used for allocating positive AP. And negative congestion uplift quantities are used for negative AP. Table 15.7 shows the positive and negative congestion uplift quantities for the MP B and the total quantities for all MPs— there are two MPs (MP A and MP B) in this example. This data will be used for calculating congestion uplift payments in Section 15.5.

Table 15.7   Congestion uplift quantity

Schedule (s)	MP B		Total all MPs	
	Positive Congestion GJ	Negative Congestion GJ	Positive Congestion GJ	Negative Congestion GJ
1	17.2	0.0	38.1	0.0
2	0.0	−2.0	0.0	−2.0
3	0.0	0.0	1.0	0.0
4	0.0	0.0	1.0	0.0
5	0.0	0.0	0.0	0.0

15.4.3   Common uplift quantity

Common uplift quantity is AEMO's residual demand forecast override, which cannot be allocated to any MP or other causing participant. This data is used for calculating common uplift payments, which is apportioned to all withdrawing MPs.

Table 15.8 summarises the three types of uplift quantities—surprise, congestion and common—which form the basis for allocating APs and calculating UPs.

Table 15.8   Total uplift quantities

Schedule	Surprise uplift GJ		Congestion uplift GJ		AEMO residual override GJ		Total uplift GJ	
	Positive	Negative	Positive	Negative	Positive	Negative	Positive	Negative
1	1.0	0.0	38.1	0.0	0.0	−1.0	39.1	−1.0
2	1.0	−10.3	0.0	−2.0	1.0	−1.0	2.0	−13.3
3	5.0	−1.0	1.0	0.0	3.0	0.0	9.0	−1.0
4	3.0	−1.0	1.0	0.0	1.0	−1.0	5.0	−2.0
5	0.0	−3.0	0.0	0.0	2.0	0.0	2.0	−3.0

15.5 Uplift payments

The total AP for each schedule is allocated to the three types of UP based on the calculated uplift quantities (shown in Table 15.8). Firstly, AP is allocated by type of uplift (Section 15.5.1), and then the uplift payments are allocated to market participants (Section 15.5.2).

Under certain scenarios, the uplift rate ($/GJ) that applies to congestion and surprise uplift payments can exceed the associated AP rate. The lesser of the AP rate and the uplift rate is used to allocate the total AP to each uplift type.

The uplift rate cap was introduced in late 2010 to ensure that the effective price cannot exceed VOLL. The capping algorithm ensures that the uplift payment rates are not greater than the average ancillary payment rates and, hence, cannot exceed VOLL.

15.5.1   Allocations of ancillary payments by type of uplift

The total AP is apportioned to each type of uplift according to the calculated uplift quantities as shown in Table 15.8. Note that common UPs also include:

- The amount of DTSSP congestion uplift payments in excess of their liability limits.

- The amount of excess UPs beyond the capped congestion UPs and surprise UPs (see step 4).

- Residual APs not allocable to any type of UPs.

The steps to allocate ancillary payments to each uplift type are as follows:

Step 1 – Calculate the average ancillary payment rates for each schedule

The average AP rate (APR) for each schedule is calculated by dividing the total AP amount for that schedule by the total positive or negative CUIQ, depending on the sign of the total AP. In step 3, this rate is compared with the initial uplift payment rate calculated in step 2.

That is, where,

s is the schedule, where $s=1$ is the 6 AM schedule
$TUP(s)$ is the total ancillary payment in schedule s
$CUIQP(s)$ is the total positive constrained-up injection quantity in schedule s in GJ
$CUIQN(s)$ is the total negative constrained-up injection quantity in schedule s in GJ

The AP rate (APR) for schedule s is calculated by:

If $TUP(s)<0$

$$APR_s = {TUP(s)} \big/ {CUIQN(s)} \quad\text{...}(20)$$

If $TUP(s)>0$

$$APR_s = {TUP(s)} \big/ {CUIQP(s)} \quad\text{...}(21)$$

Step 2 – Calculate initial uplift payment rate

The initial uplift payment rate ($IUPR$) is calculated by dividing the total uplift payment for a schedule by the total positive or negative uplift quantities for that schedule, depending on the sign of the total UP.

That is, where,

s is the schedule, where $s=1$ is the 6 AM schedule
$TUP(s)$ is the total uplift payment in schedule s
$QIP(s)$ is the total positive injection quantity in schedule s in GJ
$QIN(s)$ is the total negative injection quantity in schedule s in GJ

The initial uplift rate (IUR) for schedule s is calculated by:

If $TUP(s)<0$

$$IUPR_s = {TUP(s)} \big/ {QIN(s)} \quad\text{...}(22)$$

If $TUP(s)>0$

$$IUPR_s = {TUP(s)}/{QIP(s)} \dotfill (23)$$

Step 3 – Cap uplift payment rate

The minimum of the ancillary payment rate (step 1) the initial uplift payment rate (step 2) for each schedule is used to calculate congestion and surprise uplift payments in step 4.

$$UPR_s = MIN(APR_s, IUPR_s) \dotfill (24)$$

Step 4 –Calculate uplift payments for each uplift type using the revised uplift rates

The congestion and surprise uplift payments are calculated using the revised uplift payment rate in each schedule, and the residual uplift payment is allocated to common uplift payments.

Where,

s is the schedule, where $s=1$ is the 6 AM schedule

QUC_s is the congestion uplift quantity in schedule s in GJ

QUS_s is the surprise uplift quantity in schedule s in GJ

UPR_s is the revised uplift payment rate in schedule s in \$/GJ

TUP_s is the total uplift payment in schedule s

The congestion uplift payment in schedule s is calculated by:

$$CUP_s = QUC_s \times UPR_s \dotfill (25)$$

The surprise uplift payment in schedule s is calculated by:

$$SUP_s = QUS_s \times UPR_s \dotfill (26)$$

The common uplift payment in schedule s is calculated by:

$$MUP_s = TUP_s - (CUP_s + SUP_s) \dotfill (27)$$

An example of calculations of uplift payments

The following examples assume there are no residual DTSSP congestion uplift payments and residual APs to be allocated to MPs. The common UP therefore only includes uplift costs due to AEMO's residual demand forecast overrides and excess UPs beyond the capped congestion and surprise UPs. Positive and negative APs are allocated separately.

Step 1

In Table 15.9, the total AP values come from Table 13.12. The equation applied to calculate the AP rate (Eq. 20 or 21) depends on the sign of the TUP value in each schedule.

Table 15.9   Calculation of AP rate

Schedule	Total AP $	Total CUIQ GJ		AP rate $/GJ
		Positive	Negative	
s	TUP	CUIQP	CUIQN	APR
1	0.0	0.0	−2.0	0.0
2	−100.0	4.0	−10.0	10.0
3	−200.0	12.0	−3.0	66.7
4	200.0	6.0	−4.0	33.3
5	0.0	3.0	−2.0	0.0
				Eqs 20, 21

Step 2

The initial UP rate for each schedule is calculated in Table 15.10. In this step, the equation applied to calculate the UP rate (Eq. 22 or 23) depends on the sign of the TUP value in each schedule.

Table 15.10   Calculation of initial UP rate

Schedule	Total UP $	Total uplift quantity GJ		Initial UP rate $/GJ
		Positive	Negative	
s	TUP	QIP	QIN	IUPR
1	0.0	39.1	−1.0	0.0
2	−100.0	2.0	−13.3	7.5
3	−200.0	9.0	−1.0	200.0
4	200.0	5.0	−2.0	40.0
5	0.0	2.0	−3.0	0.0
				Eqs 22, 23

Step 3

In Table 15.11 Equation 24 is then applied to the APR and IUPR values taken from the previous two tables.

Table 15.11   Calculation of UP rate

Schedule	AP rate $/GJ	Initial UP rate $/GJ	UP rate $/GJ	
			Positive	Negative
s	APR	$IUPR$	UPR^+	UPR^-
1	0.0	0.0	0.0	0.0
2	10.0	7.5	0.0	7.5
3	66.7	200.0	0.0	66.7
4	33.3	40.0	33.3	0.0
5	0.0	0.0	0.0	0.0
			Eq. 24	

Step 4

Results in Table 15.12 are calculated by applying equations 25, 26, and 27 to the revised uplift payment rates in Table 15.11 and the uplift payment quantities in Table 15.8.

Table 15.12   Calculation of uplift payments

Schedule	Congestion uplift payment $	Surprise uplift payment $	Total UP $	Common uplift payment $
s	CUP	SUP	TUP	MUP
1	0.0	0.0	0.0	0.0
2	−15.0	−77.4	−100.0	--7.5
3	0.0	−66.7	−200.0	−133.3
4	33.3	100.0	200.0	66.7
5	0.0	0.0	0.0	0.0
	Eq. 25	Eq. 26		Eq. 27

In this example, note that:

- In schedule 3, the surprise uplift payment is capped from –$200.0 to –$66.7.

- In schedule 4, the congestion uplift payment is capped from $40.0 to $33.3, and the surprise uplift payment is capped from $120.0 to $100.0.

- In schedules 2, 3, and 4, the residual TUP (includes the capped amounts) is allocated to the common uplift payment.

15.5.2 Allocations of uplift payments to market participants

For each schedule, an MP's surprise and congestion uplift payments are calculated by applying the uplift payment rates (positive or negative) to the MP's individual positive or negative uplift quantity for that schedule:

Where,

s is the schedule, where $s=1$ is the 6 AM schedule

$QUS_s(p)$ is the surprise uplift quantity for market participant p in schedule s in GJ

$QUC_s(p)$ is the congestion uplift quantity for market participant p in schedule s in GJ

UPR_s^+ is the positive uplift payment rate in schedule s in \$/GJ

UPR_s^- is the positive uplift payment rate in schedule s in \$/GJ

The surprise uplift payment (SUP) to market participant m in schedule s is calculated by:

Where $QUS_s(p)>0$,

$$SUP_s(p) = QUS_s(p) \times UPR_s^+ \quad\text{...(28)}$$

And where $QUS_s(p)<0$,

$$SUP_s(p) = QUS_s(p) \times UPR_s^- \quad\text{...(29)}$$

Similarly, the congestion uplift payment (CUP) to market participant p in schedule s is calculated by:

Where $QUC_s(p)>0$,

$$CUP_s(p) = QUC_s(p) \times UPR_s^+ \quad\text{...(30)}$$

And where $QUC_s(p)<0$,

$$CUP_s(p) = QUC_s(p) \times UPR_s^- \quad\text{...(31)}$$

And, for each schedule, an MP's share of total common uplift payments is calculated by the ratio of the MP's daily actual withdrawals to the total of all MP's daily actual withdrawals—see Table 12.2 for the withdrawal share of each MP:

Where,

s is the schedule, where $s=1$ is the 6 AM schedule

MUP_s is the total common uplift payment in schedule s

$MUP_s(p)$ is the common uplift payment for market participant p in schedule s

$QWA(p)$ is the total daily withdrawal quantity for market participant p in GJ

$$MUP_s(p) = MUP_s \times \frac{QWA(p)}{\sum_p QWA(p)} \quad\text{...(32)}$$

Example calculations of uplift payments to MPs

Table 15.13, Table 15.14, and Table 15.15 demonstrate how each type of uplift payment is allocated to a market participant.

Note. Only the allocations to MP B are shown in the following tables.

Table 15.13   Allocations of surprise uplift payments to market participants

| Schedule | Positive surprise uplift payments | | | Negative surprise uplift payments | | | |
| | Positive uplift payment rate | MP B positive surprise uplift quantity | MP B surprise uplift payment | Negative uplift payment rate | MP B negative surprise uplift quantity | MP B surprise uplift payment | MP B total surprise uplift payment |
	$/GJ	GJ	$	$/GJ	GJ	$	$
s	UPR^+	QUS^+	SUP^+	UPR^-	QUS^-	SUP^-	$SUP^+ + SUP^-$
1	0.0	1.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	7.5	−10.3	−77.4	−77.4
3	0.0	5.0	0.0	66.7	0.0	0.0	0.0
4	33.3	3.0	100.0	0.0	0.0	0.0	100.0
5	0.0	0.0	0.0	0.0	−2.0	0.0	0.0
See	Table 15.11	Table 15.3	Eq. 28	Table 15.11	Table 15.3	Eq. 29	

Table 15.14   Allocations of congestion uplift payments to market participants

| Schedule | Positive congestion uplift payments | | | Negative congestion uplift payments | | | |
| | Positive uplift payment rate | MP B positive congestion uplift quantity | MP B congestion uplift payment | Negative uplift payment rate | MP B negative congestion uplift quantity | MP B congestion uplift payment | MP B total congestion uplift payment |
	$/GJ	GJ	$	$/GJ	GJ	$	$
s	UPR^+	QUC^+	CUP^+	UPR^-	QUC^-	CUP^-	$CUP^+ + CUP^-$
1	0.0	17.2	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	7.5	-2.0	−15.0	−15.0
3	0.0	0.0	0.0	66.7	0.0	0.0	0.0
4	33.3	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
See	Table 15.11	Table 15.7	Eq. 30	Table 15.11	Table 15.7	Eq. 31	

Table 15.15   Allocations of common uplift payments to market participants

Schedule	MP B's actual daily withdrawal GJ	Total all MPs' daily actual withdrawals GJ	MP B's proportion of actual withdrawals %	Total common UP $	MP B's common UP $
s	$QWA(p)=A$	$\sum_p QWA(p)=B$	A/B	MUP_s	$MUP_s(p)$
1				0.0	0.0
2				−7.5	−4.0
3	135	253	53	−133.3	-71.1
4				66.7	35.6
5				0.0	0.0
See	Table 12.2		Eq. 32	Table 15.12	Eq. 32

Appendix A   Glossary of Terms

The descriptions in this glossary are provided only to assist the reader's understanding of the terms used in this document. For definitions of these terms, the reader should always refer to the applicable NGR. The terms listed relate only to the DWGM and, as such, modifiers such as "DWGM …", "Victorian", and "in accordance with the NGR", are implied and have been omitted from the descriptions unless their omission might cause misreading. Selected, generic terms in common usage are also provided. Terms marked as obsolete (obs.) terms are provided for completeness and should be avoided. Technical terms such as linepack, market participant, and service provider are, in general, not capitalised nor italicised. Capitalisation indicates that the term is either a formal title (Declared Transmission System, for example) or the name of a facility or place (Dandenong City Gate, for example). Whereas italics indicate that the term is a published title, such as an act of parliament, an AEMO publication, or a publication from another source.

allocation agent

A person appointed by a market participant to submit injection allocation statements or withdrawal allocation statements on their behalf.

AMDQ

A collective term for the transportation rights on the DTS, which includes *authorised MDQ* and *AMDQ credits*.

AMDQ credit

Transportation rights that were allocated on additions to the original DTS pipeline system—above the initial 990 TJ of authorised MDQ on the Melbourne–Longford pipeline system. See also *authorised MDQ* and *AMDQ*.

augmentation

The process of upgrading the capacity or service potential of a transmission (or a distribution) pipeline.

authorised MDQ

Transportation rights that were allocated for the original 990 TJ capacity on the Melbourne–Longford pipeline system when the DTS was first set up. See also *AMDQ credits* and *AMDQ*.

bid

A quantity of gas at a specified price that a market participant offers to inject into or withdraw from the transmission system during a gas day.

bid stack

Incremental gas quantities by injection point, offered by market participants and stacked in price order.

BassGas

A project that sources gas from the Bass Basin for supply to the DTS and is injected at Pakenham.

BOD linepack

Beginning-of-day linepack (BOD LP) is equal to the EOD LP from the previous gas day. See also EOD linepack.

city gate

A facility on the transmission pipeline system where, typically, gas undergoes changes of pressure and temperature and is measured before it enters the lower pressure distribution pipeline system.

connection point

A delivery point, transfer point, or receipt point.

constraint

Any limitation causing a defined gas property (such as minimum pressure) to fall outside its acceptable range.

Culcairn

The transmission system interconnection point between Victoria and New South Wales.

customer

Any party who purchases and consumes gas. Customers can act through retailers, or they can participate directly in the market as market participants.

delivery point

The point at which gas is withdrawn from a pipeline and delivered to a customer or injected into a storage facility.

distribution

The transport of gas over a combination of high pressure and low pressure pipelines from a city gate to customer delivery points.

distribution pipeline

Pipelines that transport gas from the transmission pipelines to the consumer or customer. A distribution pipeline has a maximum allowable operating pressure of 515 kPa, or, where the maximum operating pressure is greater than 515 kPa, are uniquely identified as a distribution pipeline in a distributor's access arrangement.

distributor

The owners of the distribution pipelines, which transport gas from the transmission pipelines to the consumer or customer.

Declared Transmission System (DTS)

Owned by APA Group and operated by AEMO, the Declared Transmission System serves Gippsland, Melbourne, Central and Northern Victoria, Albury, the Murray Valley region, Geelong and extends to Port Campbell.

DTS constraint

A constraint on the Declared Transmission System. See also constraint.

EOD linepack

End-of-day linepack (EOD LP) is measured at the end of a gas day at 6 AM. EOD LP is equal to the BOD LP for the next gas day.

ex ante

From the Latin "from before", meaning something that occurs before the event. In the case of gas markets, an ex ante market is one in which the price is set before the gas is withdrawn by consumers. Whereas, an ex post market sets the price after the gas is withdrawn. The DWGM is an ex ante market with ex post adjustments.

expansion

An increase in the capacity or service potential of a transmission pipeline or a distribution pipeline by replacing or enhancing existing plant or equipment, or by adding new plant or equipment.

extension

A new pipeline built to enlarge the area to which gas can be supplied, including extensions that connect together pre-existing pipeline systems or extend the supply of gas at transmission pressure within a distribution area.

gas day

A period of 24 consecutive hours beginning at 6:00 AM (0600 hrs) EST.

injection

The physical injection of gas into the transmission system.

The Interconnect

Refers to the pipeline from Barnawartha to Wagga Wagga, which connects the Victoria and New South Wales transmission systems. The point of connection is at Culcairn. This does not include the VicHub (Longford) and SEA Gas (Iona) interconnections.

linepack

The pressurised volume of gas stored in the pipeline system. Linepack is essential for gas transportation through the pipeline network throughout each day and is required as a buffer for intraday balancing.

liquefied natural gas (LNG)

Natural gas that is compressed at high pressure and stored as a fluid. LNG is vaporised when injected into the transmission pipeline system. LNG is typically used as a back-up supply of gas during periods of peak demand and during emergencies.

LNG

See *liquefied natural gas.* Also used to describe the Melbourne LNG storage facility located at Dandenong.

Market Information Bulletin Board (MIBB)

A facility established by AEMO on the electronic communication system on which it publishes information for market participants.

market customer

A gas customer who is a market participant.

market, gas market

A market administered by AEMO for the injection of gas into and the withdrawal of gas from the transmission system and the balancing of gas flows in or through the transmission system.

market participant

A party who is eligible, by registration with AEMO, to trade gas on the spot market in accordance with the National Gas Rules.

maximum daily quantity (MDQ)

Maximum daily quantity of gas supply or demand.

market prices

Prices for gas set by AEMO for each scheduling horizon..

maximum hourly quantity (MHQ)

Maximum hourly quantity of gas supply or demand.

MIRN

Metering Installation Registration Number

***Market and System Operations Rule*s (MSOR) (obs.)**

Replaced by the NGR.

natural gas

A naturally occurring hydrocarbon composed of between 95% and 99% methane (CH_4), with the remainder predominantly being ethane (C_2H_6).

participant

A person registered with AEMO in accordance with the NGR.

peak shaving

Meeting the demand peak using injections of vaporised LNG.

pipeline

A pipe or system of pipes for or incidental to the conveyance of gas and includes a part of such a pipe or system.

pipeline injections

The injection of gas into a pipeline.

price (bid) step

A price and quantity defining the quantity of gas that a market participant, if scheduled by AEMO, will inject into or withdraw from the transmission system.

reference hub

A notional site within the gas transmission system established for the purpose of valuing authorised MDQ and AMDQ credit certificates—when an MP does not nominate its entire AMDQ to actual sites, it has to nominate its residual AMDQ somewhere.

retailer

Those selling the bundled product of energy services to the customer.

Retail Market Procedures

Procedures made under the *National Gas Rules* Part 15B in relation to the retail gas market.

scheduling

The process of scheduling nominations and bids, which AEMO carries out in accordance with the NGR, for the purpose of balancing gas flows in the transmission system and maintaining the security of the transmission system.

SEA Gas Pipeline

The 680 km pipeline from Port Campbell to Adelaide connected to the Minerva plant and the DTS and the UGS at Iona, constructed principally to ship gas to South Australia.

SEA Gas Interconnect (also Iona Interconnect)

The interconnection between the SEA Gas pipeline and the DTS at Iona.

Service Envelope Agreement (SEA)

An agreement entered between AEMO and a Declared Transmission System Service Provider (DTSSP)by which the DTSSP provides AEMO with gas transportation services and pipeline capacity..

South West Pipeline (SWP)

The 500 mm diameter pipeline from Lara (Geelong) to Iona.

storage facility

A facility for storing gas, such as the Dandenong LNG storage facility and the Iona UGS.

system capacity

The maximum demand that can be met on a sustained basis over several days under a defined set of operating conditions. These conditions include but are not limited to load distribution, hourly load profiles at delivery points, heating values and the specific gravity of injected gas at injection points, linepack and its distribution throughout the system, ground and ambient air temperatures, minimum and maximum operating pressure limits at critical points throughout the system; and the capacities of compressor stations.

system constraint

See Declared Transmission System (DTS) constraint.

system injection point

A transmission system connection point designed to permit gas to flow through a single pipe into the transmission system, which may also be, in the case of a transfer point, a system withdrawal point.

system withdrawal point

A transmission system connection point designed to permit gas to flow through a single pipe out of the transmission system, which may also be, in the case of a transfer point, a system injection point.

system withdrawal zone (SWZ)

Part of the transmission system that contains one or more system withdrawal points that AEMO considers as a single withdrawal zone for the purposes of nominations and bids.

Tariff D

The transportation tariff applying to daily metered sites with annual consumption greater than 10,000 GJ or MHQ greater than 10 GJ and that are assigned as Tariff D in the AEMO meter installation register. Each site has a unique meter ID number (MIRN).

Tariff V

The transportation tariff applying to non-tariff D load sites. This includes residential and small to medium-sized commercial and industrial gas users.

transfer agent

A person or organisation who acts on the behalf of the holder of transportation rights for the purpose of transferring authorised MDQ or AMDQ credit certificates.

transferee

The recipient of transferred transportation rights—that is, authorised MDQ or AMDQ credit certificates.

transferor

The person or organisation holding transportation rights who transfers authorised MDQ or AMDQ credit certificate to another party (the transferee).

transmission

Long-haul transportation of gas by high pressure pipelines.

transmission customer

A customer that withdraws gas from a transmission delivery point.

transmission pipeline

Defined as a pipeline that is not a distribution pipeline—typically a high-pressure pipeline that transports gas from a producer or storage facility to a low-pressure distribution system

Declared Transmission System Service Provider (DTSSP)

The owner (or leaseholder) of a transmission pipeline that is to be operated by AEMO.

transmission system

The system of transmission pipelines, compressor stations, and other plant that form the gas transmission system.

unaccounted-for-gas (UAFG)

The difference between measured quantity of gas injected into the transmission system and the measured quantity of gas withdrawn at delivery points. UAFG comprises gas losses, metering errors, timing, heating value error, allocation error, and other factors.

Underground Gas Storage (UGS)

The Underground Gas Storage facility at Iona.

VicHub

The interconnection between the EGP and the DTS at Longford, which facilitates gas trading at the Longford hub.

VOLL

A price cap, being the maximum, on the market price.

Western Transmission System (WTS)

Transmission pipelines serving Port Campbell to Portland and Western District from Iona.

Appendix B   References

Unless otherwise indicated, the following documents are AEMO publications and are available from the AEMO website at www.aemo.com.au or by application to AEMO at Level 22, 530 Collins Street, Melbourne, Victoria 3000. These documents are updated regularly, hence the date of publication has been omitted—check the website to obtain the most recent version.

B.1   Market Guides

[1]   *Guide to the Victorian Gas Wholesale Market*
[2]   *Technical Guide to the Declared Wholesale Gas Market* (this guide)
[3]   *Technical Guide to the Victorian Gas Retail Market*

B.2   Planning

[4]   *Victorian Annual Planning Report*
[5]   *Gas Statement of Opportunities*

B.3   Procedures and guidelines

Gas scheduling

[6]   *Gas Scheduling Procedures*
[7]   *System Security Procedures*
[8]   *Connection Approval Procedures*
[9]   *Demand Override Methodology*
[10] *Accreditation Procedures*
[11] *Maintenance Planning Procedures*
[12] *Injection Tie-Breaking Right Functional Design*

Settlement

[13] *AMDQ Transfer Algorithm*
[14] *AMDQ Transfer Procedures*
[15] *AMDQ Transfer Guidelines*
[16] *AMDQ Credit Nomination Process*
[17] *AMDQ Auction Procedures*
[18] *Administered Pricing Procedures*
[19] *Ancillary Payment Procedures*
[20] *Ancillary Payment Functional Design*
[21] *Compensation Procedures*
[22] *Uplift Payment Procedures*
[23] *Uplift Payment Functional Design*
[24] *GMCC07-017-01 Committee paper* (GMCC meeting 124)
[25] *GMCC08-084-09 Committee paper* (GMCC meeting 136)

Emergency

[26] *Gas Emergency Protocol*
[27] *Gas Load Curtailment and Gas Rationing and Recovery Guidelines*

Data access

[28] *Electronic Communication Procedures*
[29] *WebExchanger User Guide*
[30] *MIBB Report Participant Guide*

Metering

[31] *Gas Quality Guidelines*
[32] *Interval Meter Registration Process*
[33] *Metering Communication Procedures*
[34] *Energy Calculation Procedures*
[35] *Data Validation Procedures*
[36] *Metering Uncertainty and Calibration Requirements Procedures*
[37] *Metering Register Procedures*
[38] *Installation Database Procedures*
[39] *Distribution UAFG Procedures*
[40] *Interval Meter Registration Process*

Retail

[41] *Retail Market Procedures*

B.4   Legislation

[42] *The Victorian Gas Industry Act*
Available from the Victorian Legislation and Parliamentary Documents website
www.legislation.vic.gov.au/

[43] *National Gas (South Australia) Act* 2008 (The National Gas Law)
Available from the South Australian Legislation website
www.legislation.sa.gov.au/browseActs.aspx

[44] *National Gas Rules*
Available from the Australian Energy Market Commission website
www.aemc.gov.au

B.5   Infrastructure

[45] See APA Group website for information about the DTS facilities and plant
http://www.apa.com.au/our-business/energy-infrastructure/victoria.aspx

Appendix C   The Gas Market System
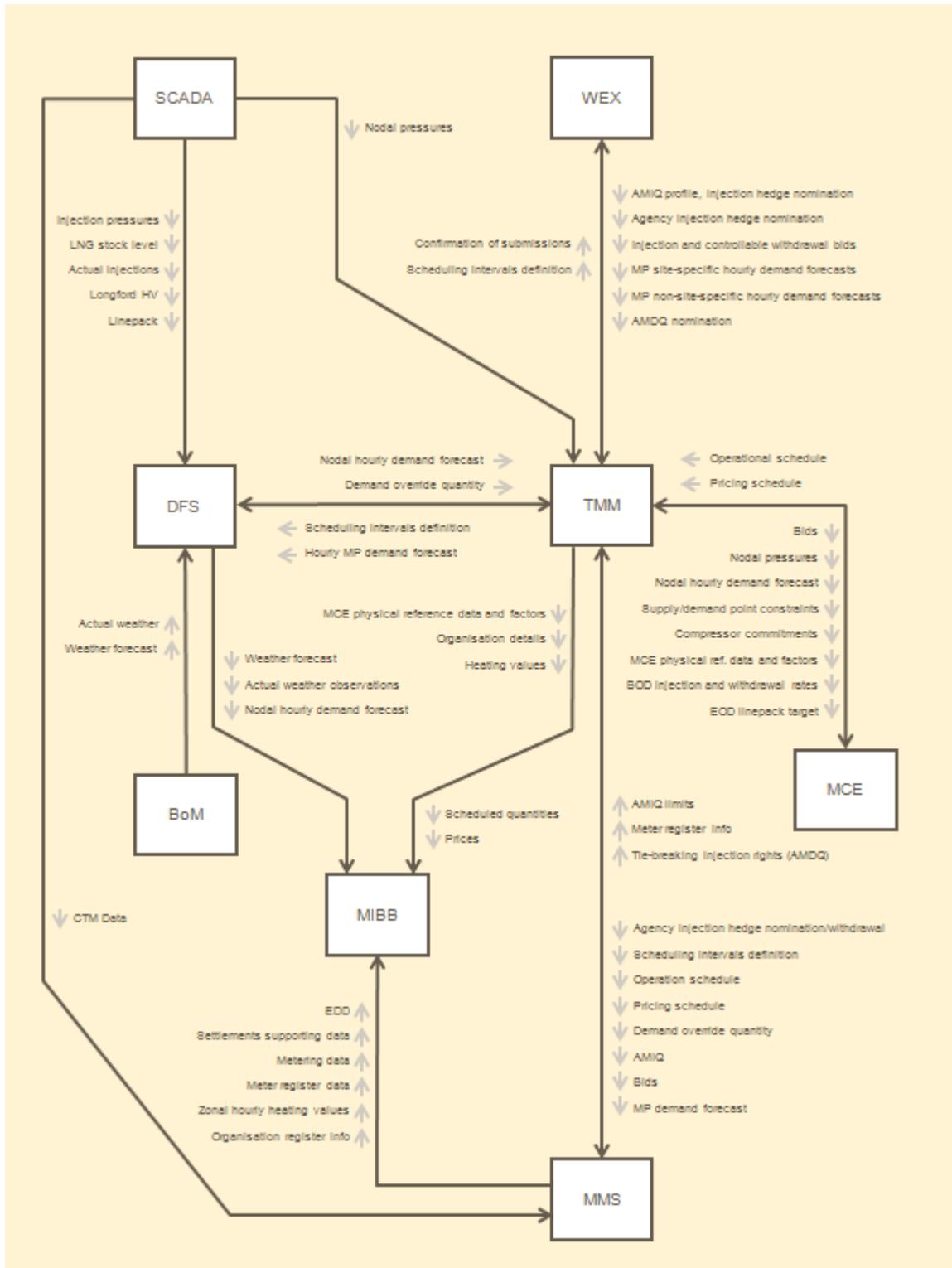
Appendix D   Determination of AMIQ

Determination of Authorised Maximum Interval Quantity (AMIQ) and Injection Tie-Breaking Rights (ITR)

Obtaining AMDQ Credits from AMDQ Credit Certificates

Determination of Authorised Maximum Interval Quantity (AMIQ) and Injection Tie-Breaking Rights (ITR)

Authorised MDQ Determination

Site (Tariff D) AMDQ
Site 1   CPP=Longford
Site n   CPP=Longford

2.1 Transfer in
2.1 Transfer out

What	2.1 Transfer AMDQ
Who	Market Participant
Rule	331
Proc.	AMDQ Transfer Procs – Ch. 3
Spec.	NA

2.2 Apply diversity factors and aggregate

What	2.2 Apply Diversity Factors
Who	AEMO
Rule	240(3)(c)(ii)
Proc.	Uplift Procs – 3.1
Spec.	Uplift Funct. Des. – 4.1

Hub AMDQ
CPP = Longford

Diversified site AMDQ
CPP = Longford

Tariff V AMDQ
CPP = Longford

2.1 Transfer in
2.1 Transfer out

2.3 Allocate in
2.3 Allocate out

What	2.3 Allocate Tariff V AMDQ
Who	AEMO
Rule	240(3)(c)(iv)
Proc.	Uplift Procs – 3.2
Spec.	Uplift Funct. Des. – 4.2

What	2.1 Transfer AMDQ
Who	Market Participant
Rule	331
Proc.	Transfer Procs – Ch. 3
Spec.	NA

Aggregate

What	2.4 Aggregation of AMDQ
Who	AEMO
Rule	240(3)
Proc.	Uplift Procs – 3.6
Spec.	Uplift Funct. Des. – 4.6

AMDQ
CPP = Longford

E ITR
B AMIQ

Curtailment Rights

Determination of Injection Hedge and Agency Injection Hedge

Determination of Authorised Maximum Interval Quantity (AMIQ) and Injection Tie-Breaking Rights (ITR)

Determination of Authorised Maximum Interval Quantity (AMIQ) and Injection Tie-Breaking Rights (ITR)

Determining Uplift Hedge and AMIQ

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