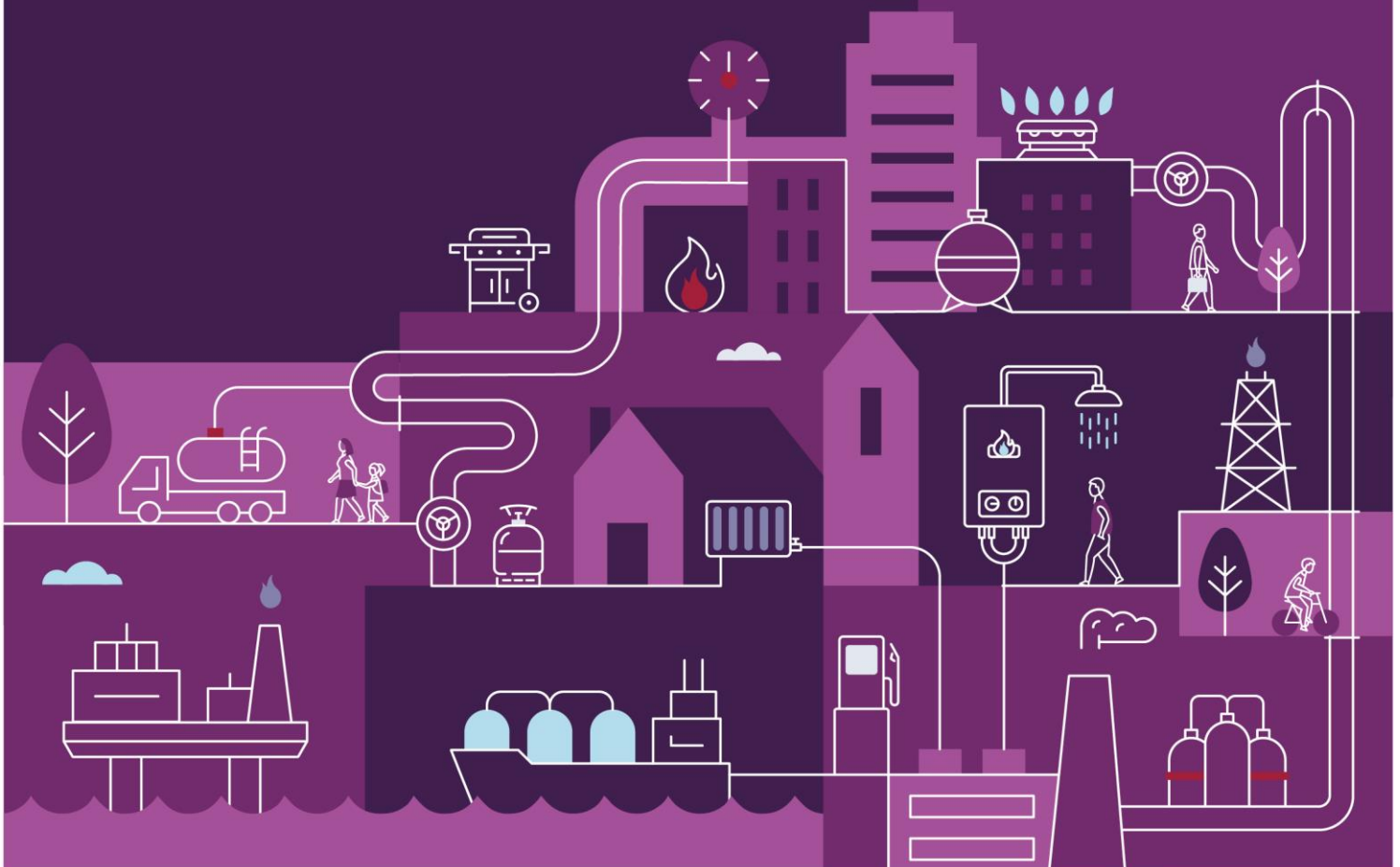


Declared Wholesale Gas Market (DWGM) Technical Guide

1 January 2023

Technical Guide

A technical overview of the operation of the Victorian
Declared Wholesale Gas Market





Important notice

Purpose

AEMO has prepared this document to provide information about the operation of the Declared Wholesale Gas Market, as at the date of publication.

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Version control

Version	Release date	Changes
1.0	1 May 2012	First version
1.1	15 July 2013	Updated maps and figures
2.0	1 January 2023	Updated to new template, adjusted for changes in Rules and Procedures including Capacity Certificates Auction and Transfers



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1 Overview of the DWGM

This chapter provides a high-level overview of the Victorian Declared Wholesale Gas Market (DWGM), 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.

1.1 Current DWGM operation

The Declared Wholesale Gas Market (DWGM) currently operates to:

- Manage gas supply, demand and linepack of the Victorian Declared Transmission System (DTS) for each gas day (starting at 6:00 AM and finishing at 5:59AM the next day).
- Facilitate trading of gas imbalances by Market Participants (MPs).
- Provide 5 intraday wholesale gas prices (at 6AM, 10AM, 2PM, 6PM and 10PM) for trading gas within each scheduling interval.
- Forecast schedules for the next gas day (D+1) schedules (at 8:00AM, 4:00PM and 12:00AM (midnight)) and 2 day ahead (D+2) schedules (at 12:00PM (noon)) to provide indicative wholesale gas prices and supply-demand balances.
- Capacity Certificates, from 1 January 2023, to provide tie breaking rights at controllable injection and withdrawal points.
- Capacity Certificates are auctioned, at least twice a year, for the next 36 months.
- Provide more efficient and transparent wholesale gas pricing signal.
- Improve market interaction and response to gas pricing signals.
- Provide adequate incentives and flexibility for demand-side response.
- Facilitate investment in pipeline infrastructure.

1.2 A brief history of the DWGM

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).
- Operated as a daily market (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.

In 2007 this review resulted in the implementation of:

- 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.

In 2017, the Australian Energy Market Commission (AEMC) undertook a review of the DWGM that resulted in the DWGM Simpler Wholesale Price and DWGM improvement to AMDQ regime rule changes. The result of these Rule changes was the replacement of AMDQ and AMDQ Credit Certificates with Injection and Withdrawal Capacity Certificates from 1 January 2023.

1.3 Who is AEMO?

The Australian Energy Market Operator (AEMO) commenced operations on 1 July 2009 superseding several state-based and cross-state organisations including the National Electricity Market Management Company Limited (NEMMCO), the Victorian Energy Networks Corporation (VENCorp) which was responsible for the efficient operation of gas and electricity industries in Victoria, the Electricity Supply Industry Planning Council (ESIPC) which was responsible for the effective operation of the electricity industry in South Australia, the South Australian operations of Retail Energy Market Company (REMC), Gas Market Company (GMC) and Gas Retail Market Operator (GRMO).

The Australian Energy Market Operator (AEMO) performs an array of gas and electricity market, operational, development and planning functions. AEMO operates the:

- National Electricity Market (NEM).
- Wholesale Electricity Market (Western Australia) (WEM).
- Victorian Declared Wholesale Gas Market.
- Victorian Declared Transmission System.
- Short Term Trading Market hubs operating in Sydney, Adelaide and Brisbane.
- Gas Supply Hubs at Wallumbilla and Moomba.

AEMO also facilitates electricity and gas full retail contestability, overseeing these retail markets in eastern and southern Australia. It is additionally responsible for national transmission planning for electricity.

1.4 AEMO's role in the Victorian DWGM

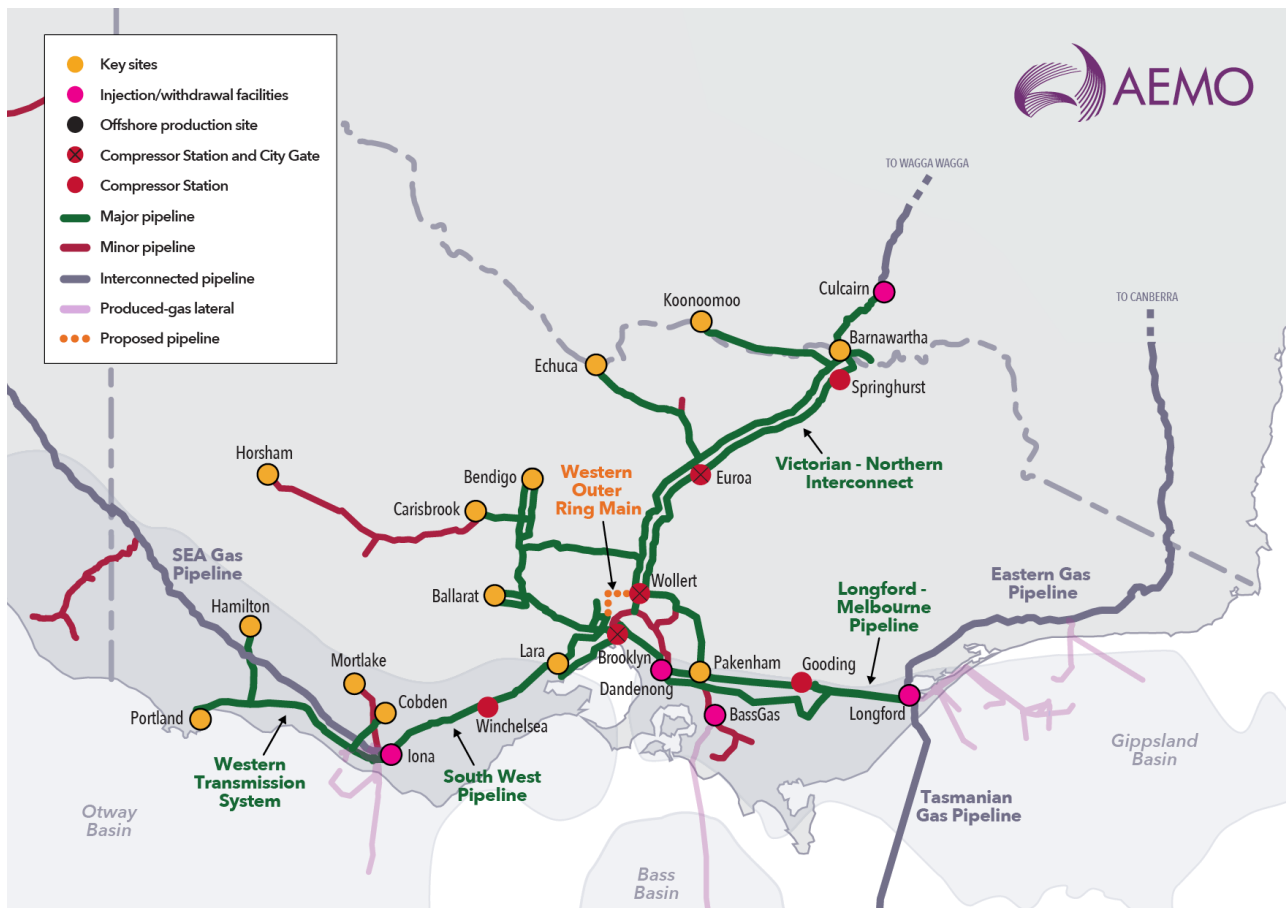
AEMO performs the following roles in the Victorian DWGM:

- 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.
- Gas Transmission Planning functions through the publication of the Victorian Gas Planning Report.

1.5 Victorian Declared Transmission System overview

The Declared Wholesale Gas Market operates to sets a gas wholesale market price for end users of the DTS, which is depicted in green in Figure 1 below. The DTS transports gas to the vast majority of Victorian households and businesses.

Figure 1 Victorian Declared Transmission System



The major pipelines that make up the DTS are:

- Longford-Melbourne pipeline (Longford-Dandenong-Wollert).
- South West Pipeline (Iona-Lara-Brooklyn).
- Victorian Northern Interconnect (to New South Wales).
- Western Transmission System (WTS) from Iona to Portland.

Other transmission pipelines, which are not part of the DTS (and are depicted in grey and red in Figure 1 above), connect the DTS to regional Victoria, New South Wales, Tasmania and South Australia; to gas production and storage facilities; and to other distribution systems. These pipelines include:

- Eastern Gas Pipeline (EGP) (Longford – Wollongong – Sydney).
- Port Campbell to Iona (PCI) pipeline.
- BassGas pipeline (Lang Lang Gas Plant – Pakenham).
- Carisbrook – Horsham pipeline.
- Culcairn – Wagga – Young pipeline (New South Wales system).
- Port Campbell to Adelaide (PCA) pipeline (SEA Gas pipeline).
- Tasmanian Gas Pipeline (Longford – Bell Bay).

1.5.1 Injection and withdrawal points

There are more than 150 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 are:

- Longford – located near Longford. Gas is supplied from the Longford Production Facility which then flows the gas to either the DTS or Eastern Gas Pipeline.
- VicHub and TasHub – Gas from Longford can be flowed to the Eastern Gas Pipeline to NSW or to the Tasmanian Gas Pipeline or to the DTS (at VicHub). The Tasmanian Gas Pipeline also has a connection to the DTS at TasHub.
- Bass Gas – located at Pakenham. Gas is supplied from the Lang Lang gas plant to the BassGas Pipeline which is connected to the DTS.
- Dandenong Liquefied natural gas (LNG) facility – Natural gas is taken from the Longford to Melbourne Pipeline, cleaned to remove moisture and carbon dioxide, and then cooled to -163° Celsius. At this temperature it becomes a liquid which is then stored in the LNG tank. Gas can be vaporised to provide supply directly to Melbourne.
- Otway, Mortlake and SEA Gas – all located near Port Campbell. Gas is supplied to the Otway Production Facility to the Otway, Mortlake or SEA Gas pipelines. These pipelines are also connected to the DTS.
- Iona – located near Port Campbell. Gas is supplied to or from the Iona Underground Gas Storage (UGS) facility.

- Culcairn – located near the Victorian and NSW border. Gas flows between the DTS and the Moomba to Sydney Pipeline system (New South Wales).

All points except for Longford and Mortlake are bi-directional – that is, gas can flow into or out of the DTS at these points.

1.6 Supply and demand in the DWGM

AEMO publishes the Victorian Gas Planning Report (VGPR) at least every two years to AEMO's website. The 2022 VGPR reports DTS annual demand is approximately 196 petajoules (PJ). This is comprised of Tariff V demand representing small residential and commercial customers of 128 PJ and Tariff D demand from large commercial and industrial demand of 65.2 PJ.

Gas transported through the DTS supplies a variety of needs, including:

- Residential, business and industrial customers.
- Gas generation—there are currently five plants connected to the DTS.
- Exports to New South Wales, Tasmania, and South Australia through the interconnected pipelines.
- Underground storage (UGS) at Iona and LNG storage at Dandenong.

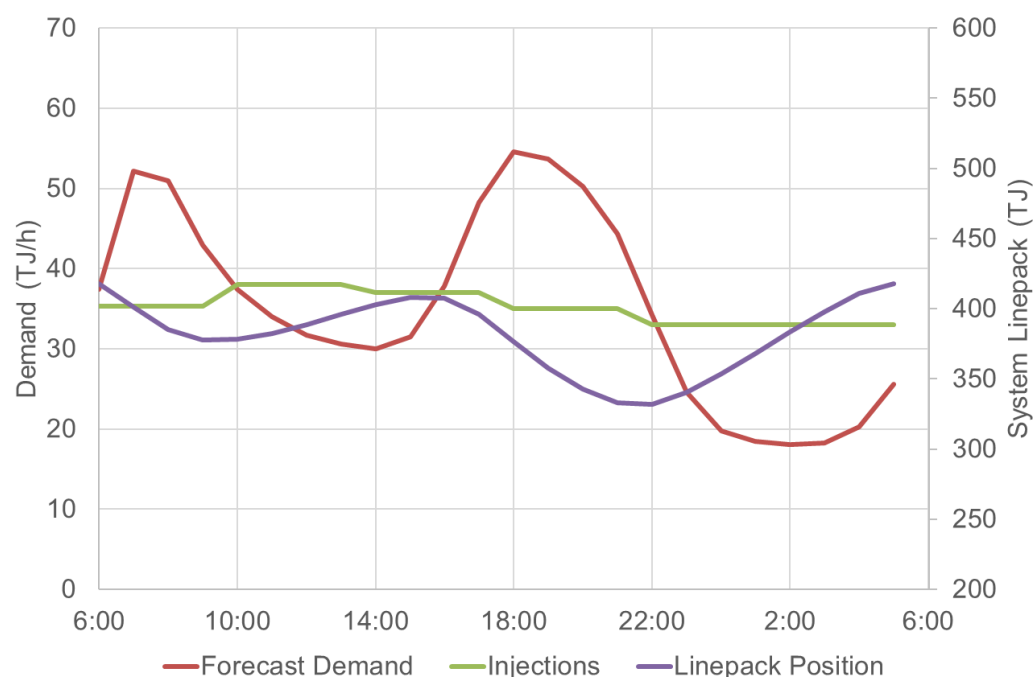
1.6.1 Daily demand

The 2022 VGPR reports peak day system demand for 2022 is expected to be:

- 1,147 terajoules a day (TJ/d) for a 1-in-2 year system demand day in 2022.
- 1,255 TJ/d for a 1-in-20 year system day in 2022.

In terms of 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.
- 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. 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, 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.

Figure 2 Example of the change in linepack across a gas day

1.6.2 Withdrawals and injections

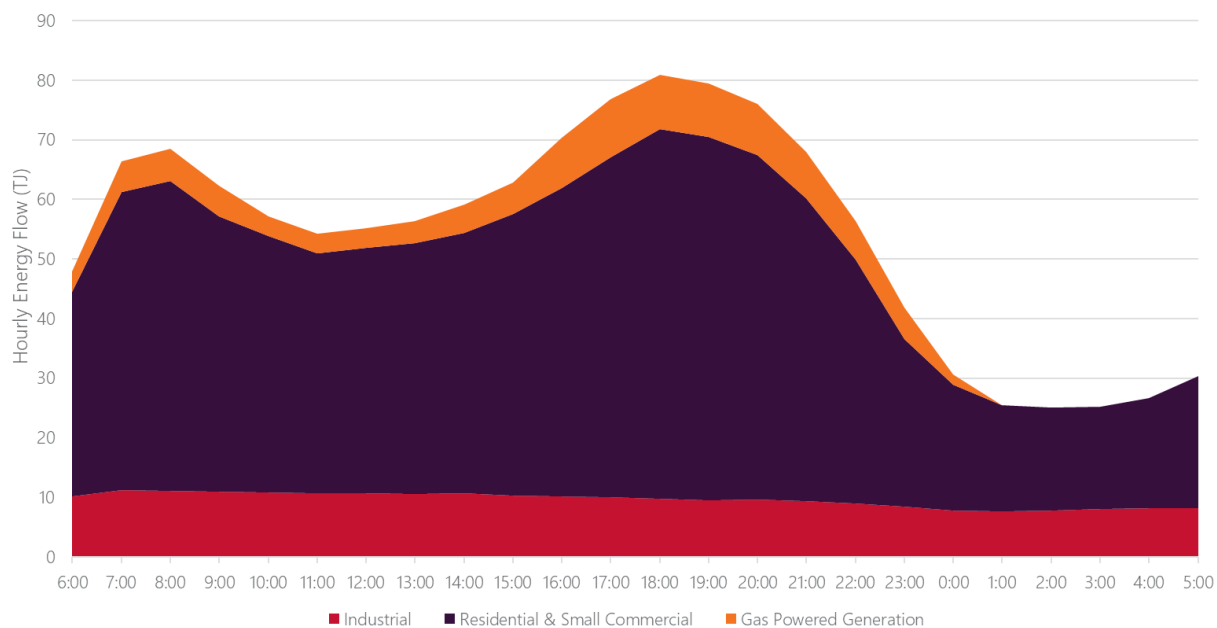
A gas day is 24 hours, commencing at 6:00 AM Australian Eastern Standard Time (AEST) and ending at 5:59 AM the next calendar day. During a gas day, Market Participants will make withdrawals from and injections into the DTS.

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 Retailers, Distribution Customers or Transmission Customers will withdraw regardless of the market price. Uncontrollable withdrawals are submitted to AEMO by Market Participants (see Industrial (ie Tariff D) and Residential and Small Commercial (ie Tariff V) in Figure 3 below) as either:
 - Non-Site Specific Demand Forecasts – this applies to almost all customers in the residential, commercial and industrial sectors. MPs provide a demand forecast to represent the aggregate demand from the end user customers they supply.
 - Site Specific Demand Forecasts – this applies large gas users’ demand, primarily being gas generation. MPs provide a demand forecast to represent the site specific demand of these large gas users.

Figure 3 Total DTS demand (system demand plus gas generation) from 9 August 2019 of 1,308 TJ/d



2 Participants in the DWGM

To participate in the DWGM, interested parties must register with AEMO. Requirements for registering as a participant in Victoria's DWGM can be found on AEMO's website¹. Interested parties are encouraged to contact AEMO prior to submitting an application so any areas of uncertainty can be discussed and clarified in advance.

The Wholesale Market in Victoria primarily involves the following Registered Market Participants, who are depicted in Figure 4, in addition to AEMO's role as Market Operator and transmission system operator:

- Retailers;
- Traders;²
- Transmission Customers; and
- Distribution Customers.

Other Participants who may be affected by the Wholesale Market, but do not participate directly in the market, include:

- Declared Transmission System Service Provider;
- Distributors;
- Interconnected Transmission Pipeline Service Providers;
- Producers;
- Storage Providers; and
- Customers (ie Tariff V (Residential and small Commercial) and Tariff D (Industrial and large Commercial Customers)).

2.1 Market operator and transmission system operator

AEMO is the market operator for the Declared Wholesale Gas Market and the operator of the Declared Transmission System. AEMO's role is established under the National Gas Law to undertake its various market and system operation functions. These functions include the management of the wholesale and retail gas market in Victoria.

2.2 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.

¹ <https://aemo.com.au/energy-systems/gas/declared-wholesale-gas-market-dwgm/register-in-the-dwgm>

² Storage Providers and Production facility operators may also be Market Participants under Part 15A of the Rules. In general, they operate as a special kind of trader usually injecting gas for sale at their facility system injection points (or in the case of a storage provider also purchasing gas at the facilities system withdrawal point).

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.

Distribution Customers

Distribution Customers have elected to participate directly in the DWGM. Distribution Customers are responsible for sourcing their own gas from the wholesale market and making commercial arrangements for transportation of the gas through the transmission and distribution networks to their premises. Distribution customers are market participants.

Transmission Customers

Transmission Customers have elected to participate directly in the DWGM and have a direct connection from the DTS to supply their facility. Transmission Customers are responsible for sourcing their own gas from the wholesale market and making commercial arrangements for transportation of the gas through the transmission networks to their premises. Transmission Customers are market participants.

2.3 Other participants

Declared Transmission System Service Provider

The Declared Transmission System Service Provider (DTSSP) maintains the gas transmission system facilities used to transport the gas between the DTS injection points (e.g. another transmission pipeline or storage facility) to DTS withdrawal points (e.g. distribution connection point or another transmission pipeline).

Producers

Producers undertake the processing of natural gas from fields for injection into the DTS. Producers are market participants when they sell gas directly to the wholesale market. Alternatively, they may be participants when they sell gas through a trader or retailer.

Storage Providers

Storage providers have facilities that store natural gas that generally has been previously transported through the DTS. This stored gas is subsequently re-injected into the DTS at a later time (e.g. during the peak winter period). Storage providers are market participants if they sell gas directly to the wholesale market. Alternatively, they may be participants if they sell gas through a trader or retailer.

An LNG Storage Provider is a specific kind of Storage Provider under Part 19 of the Rules.

Interconnected Transmission Pipeline Service Providers

Interconnected Transmission Pipeline Service Providers own, maintain and operate other transmission pipelines that connect to the DTS. The service providers interface with the Wholesale Market through the DTS connection point to transfer gas from/to their transmission pipeline.

Distributors

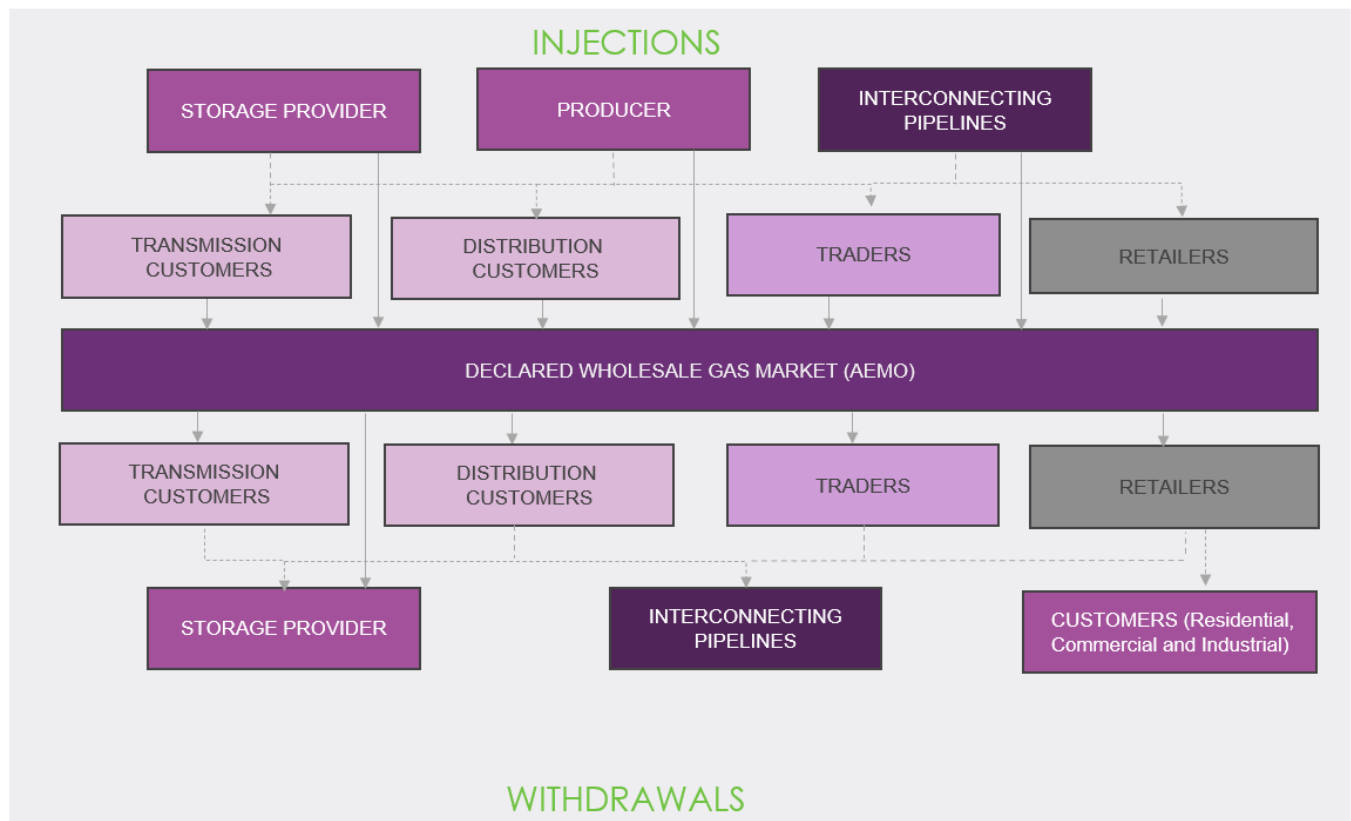
Distributors own and operate the lower pressure distribution networks. Distributors transport gas from the DTS connection point through their distribution pipelines to end-use customers.

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 gigajoules (GJ) per hour.
- Tariff V applies to residential, small to medium-sized commercial and industrial sites.

Figure 4 DWGM participants



3 Trading gas in the DWGM

This chapter provides an overview of the processes by which market participants trade gas in the DWGM.

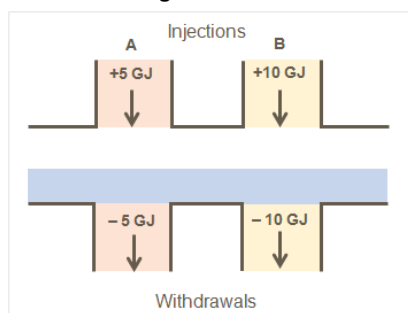
3.1 Managing imbalances

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 5 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.

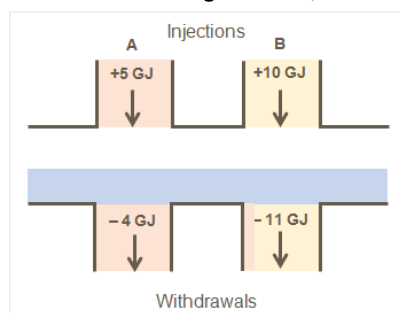
Figure 5 Gas trading examples

Scenario 1: No gas traded



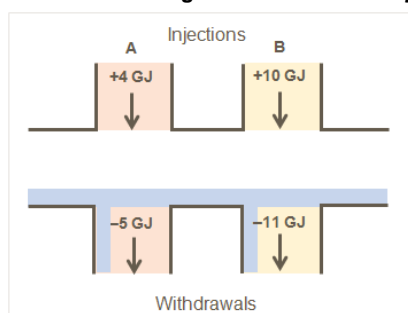
Market participants A and B withdraw the same quantities of gas as they each inject (5 TJ and 10 TJ, respectively) during a trading period. Both are in balance and there is no change in linepack. No gas is traded on the DWGM.

Scenario 2: 1 GJ of gas traded, no change in linepack



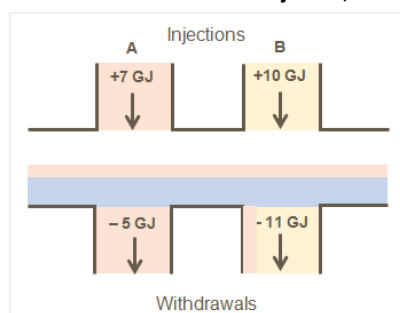
A injects 5 GJ as scheduled and withdraws 4 GJ; B injects 10 GJ and withdraws 11 GJ during a trading period. Total injections balance total withdrawals so there is no change in system linepack. A has sold 1 GJ to B at the market price, which is set by A's marginal price bid for the last GJ it injected.

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

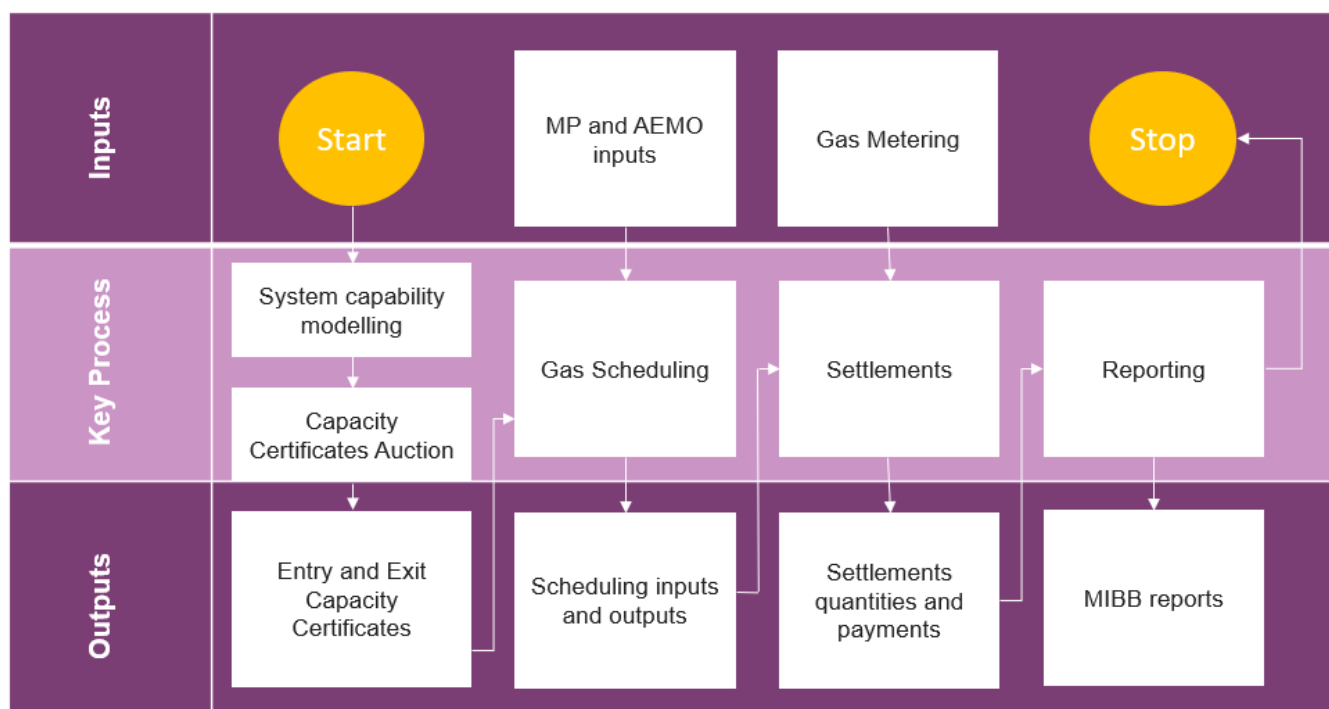


A injects 7 GJ and withdraws 5 GJ. B injects 10 GJ and withdraws 11 GJ. A sells 1 GJ to B and sells 1 GJ into system linepack at the market price.

3.2 Gas market processes

Figure 6 provides an overview of the processes that are used in producing a DWGM gas schedule.

Figure 6 Overview of key processes in the DWGM



3.2.1 Capacity Certificates Register

Entry and exit capacity certificates provide injection and withdrawal tie-breaking benefits respectively. Capacity certificates are for entry or exit within a zone determined by AEMO. These zones are published in a register on AEMO's [website](#)³. Capacity certificates will be auctioned at least twice a year, in blocks of monthly certificates.

In addition Capacity Certificates Transfers are facilitated by market systems and can be made by bilateral contract between participants. These capacity certificates are inputs to the gas scheduling, settlements and reporting processes.

The Capacity Certificates Register stores the distribution of Capacity Certificates amongst MPs and is used by the Gas Scheduling system during tie breaking.

Refer to Chapter 5 for details of the capacity certificates process.

3.2.2 Gas scheduling

Gas is scheduled by AEMO using demand forecasts, capacity certificates, 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 6 for details of the gas scheduling process.

³ See [AEMO | Entry and Exit Capacity Certificates](#).

3.2.3 Gas metering

The metering process records the gas quantities that flow through the DTS over a gas day. These gas metering flows can be split into:

- AEMO's Meter Data Agent if the site is metered by AEMO (such as transmission custody transfer meters where gas is transferred to distribution networks).
- Allocation Agents for each of the DWGM facilities which provide metering allocation to each Market Participant at that system injection point or system withdrawal point.

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 7 for details of the gas metering process.

3.2.4 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 0 for details of the settlement process.

3.2.5 Reporting

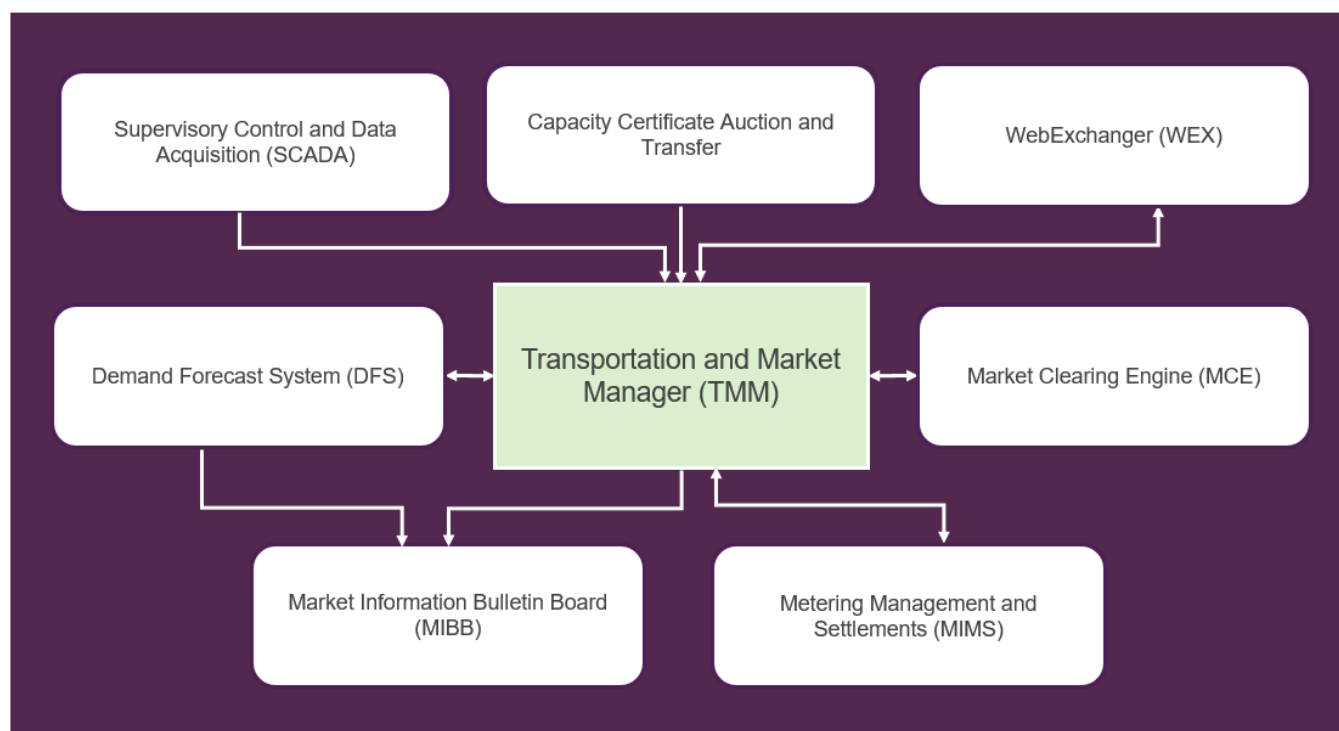
AEMO publishes information in the Market Information Bulletin Board (MIBB). The MIBB is the interface through which AEMO communicates with MPs. This provides participants with essential market data and market notices. General market information is also made available to the public through the MIBB. Refer to Section 4.8 for a description of the information available on the MIBB.

4 DWGM Gas Market Systems

The Gas Market System is the software and data by which AEMO operates the DWGM and by which participants submit information in the DWGM. It consists of eight inter-related applications.

Figure 7 shows the applications that make up the Gas Market Systems and how they are linked. These applications are described in the sections that follow.

Figure 7 Overview of the Gas Market System (GMS)



4.1 Transportation and Market Manager (TMM)

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

- Stores market information submitted by MPs via the WebExchanger – see Section 4.2.
- Stores and maintains Market Clearing Engine (MCE) reference and operational data from the SCADA system – see Section 4.5.
- Organises gas scheduling information required for initiating runs of the Market Clearing Engine (MCE) – see Section 4.6.
- Processes and stores the schedule outputs produced by 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 4.4.
- Organises market data for publication in the Market Information Bulletin Board (MIBB) – see Section 4.8.



4.2 WebExchanger (WEX)

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.

4.3 Capacity Certificates Auction and Transfer

MP's can engage AEMO to obtain entry and exit Capacity Certificates through the Capacity Certificate Auction and Transfer interface on AEMO's Markets Portal. Results of these Auctions and Transfers are recorded in TMM. Refer to Chapter 5 for details.

4.4 Demand Forecast System (DFS)

The Demand Forecast System (DFS) prepares AEMO's demand forecasts based on:

- Hourly Demand Forecasts submitted by MPs of their customer loads, including individual forecasts for very large customers (that is, gas generation site specific demand forecasts).
- Weather forecasting information.
- Historical actual weather.
- Historical load profiles.
- Historical gas demand.

AEMO's demand forecast are published on the MIBB but will only be used as part of AEMO's demand forecast override as allowed by the Wholesale Market Gas Scheduling Procedures and described in the Demand Override Methodology, both published on AEMO's website⁴.

4.5 Supervisory Control and Data Acquisition (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.

4.6 Market Clearing Engine (MCE)

The Market Clearing Engine (MCE) is the scheduling algorithm used to produce the operating and pricing schedules for the gas market based on the schedule input information passed from the TMM.

4.7 Metering Manager and Settlements (MMS)

The Metering Manager and Settlements (MMS) system has two separate components – the metering system and the settlement system.

⁴ At <https://www.aemo.com.au/energy-systems/gas/declared-wholesale-gas-market-dwgm/procedures-policies-and-guides>.

4.7.1 Metering system

- Manages the collection and storage of metered energy values from metering data agents (MDAs) 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.

4.7.2 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.

4.8 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. 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 as this information is also published to AEMO's website. 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 User Guide to MIBB Reports published on AEMO's website⁵.

⁵ At <https://www.aemo.com.au/energy-systems/gas/declared-wholesale-gas-market-dwgm/market-operations>.

5 Transportation Rights

The Australian Energy Market Commission amended the National Gas Rules (NGR) to replace Transportation Rights previously represented by authorised maximum daily quantity (AMDQ) regime in the DWGM with an entry and exit capacity certificates regime. The new regime commences on 1 January 2023.

Market participants can more easily obtain capacity certificates to manage scheduling risk through tie-breaking benefits. This creates a level playing field for all market participants to obtain capacity certificates through the primary auctions, which allows them to be allocated to those that value those most and promotes efficient use of pipeline capacity. Once allocation of pipeline capacity is chosen by market participants by allowing them to buy a set of entry and exit capacity certificates, there is greater price and volume certainty to their preferred gas transportation pathways.

Capacity certificates are for entry or exit within a zone and AEMO is required to

- Determine the capacity certificates zones and publish these in a register; and
- Conduct system capability modelling at least annually to inform AEMO's determination of the types and amounts of capacity certificates available at each auction.

This section covers the Capacity Certificates Auction and the Capacity Certificate Transfer process used to populate the Capacity Certificate Register that is used in scheduling.

5.1 Capacity certificates auction

Participation in the capacity certificates auction is restricted to market participants. Certificates will be auctioned at least twice a year, in blocks of monthly certificates that can be bid for as a single month or as a linked bid for multiple months. The auction takes place in one round with a reserve price of zero and must be conducted on a sealed bid, pay as cleared basis. All winners of a particular auction product pay the same clearing price per gigajoule (GJ) for that auction product.

Table 1 Auction schedule

Item	Regularity
Auction frequency	Six monthly auctions
Auction product window	36 months
Auction advance period	Two months
Auction timetable	Auctions run every April and November

AEMO publishes the auction notice for a capacity certificates auction on the AEMO website at least 20 business days prior to the capacity certificates auction. Each notice contains:

- The date and time of the capacity certificates auction;
- The cut-off time for bids for that capacity certificates auction;
- The auction products available at that capacity certificates auction; and
- The capacity certificates for each auction product available at that capacity certificates auction.



5.1.1 Capacity release schedule

For each auction product, Capacity Certificate type (CC-type) and month, there are six auctions before the effective date, which is three-years in advance for each to be sold.

The individual auction product is split into six tranches, one tranche allocated for each auction. The capacity release schedule determines the amount of capacity certificates that are made available for each product tranche.

5.1.2 Capacity certificate auction bidding

Participants submit bids for auction products to acquire capacity certificates. Each bid must:

- Specify a minimum bid quantity
- Specify the combination of auction products that the bid relates to
- Specify a submission of separate bids for different combinations of auction products, and
- Comprise a single bid quantity (in GJ/day) and a single bid price (in \$/GJ) for the combination of auction products specified in the bid. Combination bids, or linked bids, and standard bids have a single price that would 'win' for all products included in the bid.

5.1.3 Combination bids

Combination bids, or linked bids, permit an auction participant to submit a single bid for multiple products. Such bids are useful as the bidder can win a quantity in every product or no quantity in every product. This reduces the risk of having stranded 'capacity'. For example, a participant may choose to bid Capacity Certificates from June to December, it would not be useful to the participant if they only win in July. Another example is to link the bids across a time period allowing a participant to buy a strip of auction products for example a year. As each product is monthly, a linked bid for a year would mean buying three months of entry capacity with a bid price to be sufficient to win across all months. If successful, the participant would win the same amount of capacity for each entry product.

5.2 Capacity Certificates Transfer

Market Participants, after obtaining Capacity Certificate via the Auction, may choose to sell the Capacity Certificates via bilateral contracts. AEMO facilitates the trading of capacity certificates between participants through the Capacity Certificate Transfer process.

5.3 Capacity Certificates Register

AEMO maintains the Capacity Certificate Register and uses the register as an input to the scheduling process to determine each Market Participant tie breaking rights as discussed in Section 6.8.

5.4 Non-DTS Pipeline Capacity Trading

DWGM transportation rights are market carriage and are conveyed via entry and exit Capacity Certificate. These DTS Capacity Certificates are not subject to Pipeline Capacity Trading and the Day Ahead Auction. Only non-DTS

contract carriage pipeline capacity is subject to trading through the Pipeline Capacity Trading and Day Ahead Auction.

5.4.1 Pipeline Capacity Trading integration with the DWGM

Non-DTS pipelines capacity can be traded through the Pipeline Capacity Trading allowing pipeline capacity on contract carriage pipelines to be traded between shippers outside of the DTS. The trading of pipeline capacity can be done for any firm capacity contract registered by the pipeline operator with AEMO.

A Pipeline Capacity Trade is represented in DTS market systems via the accreditation that each market participant has registered with AEMO at each interconnected pipeline system injection point and system withdrawal point. In the event a market participant purchases via Pipeline Capacity Trading mechanism additional capacity:

- The daily pipeline capacity (in GJ terms) is divided by 24 and rounded up to the nearest GJ.
- The maximum hourly quantity in the market participants accreditation is then adjusted to reflect the pipeline capacity purchased.
- If the market participants accreditation has a NULL maximum hourly quantity then the accreditation will not be adjusted to reflect the pipeline capacity trade.

5.4.2 Day Ahead Auction integration with the DWGM

Non-DTS pipelines capacity can also be traded through the Day Ahead Auction which trades firm capacity available on pipelines that has not been nominated by shippers to a daily auction. In the event the shipper with the firm capacity needs to use it on the gas day they may recall this capacity.

Similar to a Pipeline Capacity Trade, discussed in section 5.4.1, once the capacity auction is settled AEMO adjusts the market participant accreditation at the system injection point or system withdrawal point specified to allow the participant bids to be scheduled in the following schedules.

In the event the firm Shipper recalls the capacity, the market participant that wins the auction does NOT have its accreditation readjusted to reflect the lost capacity. The Market Participant is responsible for adjusting its bids to reflect the DAA auction outcome along with any recalled capacity.

6 Gas scheduling

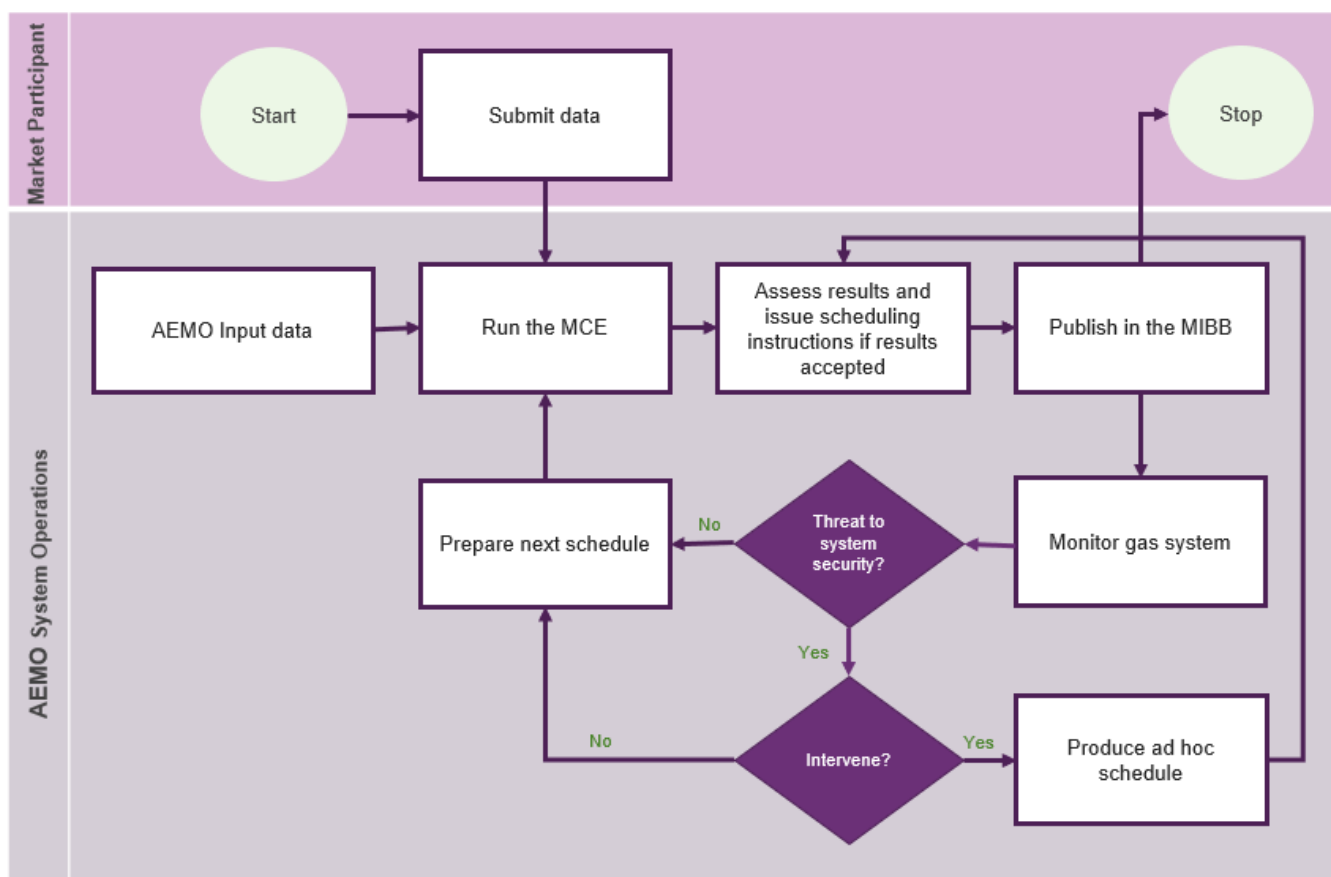
AEMO produces operating schedules a number of times each gas day for each MP, which specify the market price and each MP's injection quantities and controllable withdrawals. The scheduling algorithm is used to optimising each operating schedule and minimises the cost of supplying the forecast gas demand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

Note: For more information about the gas scheduling process, refer to the [Wholesale Market Gas Scheduling Procedures](#).

6.1 Overview of the gas scheduling process

Figure 8 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 6.2) or abnormal conditions (see Section 6.3).

Figure 8 The gas scheduling process



6.2 Normal operating conditions

Under normal operating state, defined in the Wholesale Market System Security Procedure⁶, 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 6.5), prepares its own input data and demand forecasts (see Section 6.6), and, if required, overrides demand forecasts from MPs (see Section 6.6.1).
- AEMO runs the Market Clearing Engine (MCE) based on the input data to produce the optimal schedules (see Section 6.4).
- AEMO assesses the schedules produced by the MCE.
- AEMO issues pricing and operating schedules (see Section 6.7) if the MCE results are accepted or reassesses the input data and repeats the process.

This occurs for each of the five current day schedules, 3 D+1 schedules and the D+2 schedule run each day.

6.3 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:

- Wholesale Market Gas Scheduling Procedures⁵
- Wholesale Market System Security Procedures⁵;
- Wholesale Market Administered Pricing Procedures⁵;
- Gas Emergency Protocol⁷; and
- Relevant sections of the National Gas Rules.

6.3.1 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. Examples of threats to system security, as described in the Wholesale Market Gas Scheduling Procedures⁵, can include:

- Gas demand exceeding DTS capacity;
- A significant unforeseen increase in gas demand;
- Gas supply sources incapable of meeting foreseen gas demand;
- A breakdown of the DTS equipment such as compressors or LNG vaporisers;
- A transmission pipeline incident (ie damage to a transmission pipeline);
- A distribution incident that significantly affects injections into or withdrawals from the DTS;
- Unplanned producer or transmission plant outages; or

⁶ At <https://www.aemo.com.au/energy-systems/gas/declared-wholesale-gas-market-dwgm/procedures-policies-and-guides>.

⁷ At <https://www.aemo.com.au/energy-systems/gas/emergency-management/victorian-role>.

- A gas supply incident, including gas quality excursions leading to off-specification gas in the DTS.

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 or off-specification gas.

Note: For more details about curtailment of customers see the Gas Load Curtailment and Gas Rationing and Recovery Guidelines⁸ and National Gas Rules Part 19, Division 5 "Intervention and Market Suspension"

6.3.2 Market Suspension

AEMO may declare the suspension of the market under NGR347(1) if:

- An emergency occurs; or
- AEMO has been directed by a government authority to suspend the Market or operate all or part of the declared transmission system in a manner contrary to the provisions of this Part; or
- AEMO determines that it is necessary to suspend the Market because it has become impossible to operate the Market.

AEMO specifically may NOT suspend the market if the:

- Market price has reached Value of Lost Load (VoLL) (currently \$800/GJ) ; or
- AEMO has issued an emergency direction; or
- AEMO has intervened in the Market because of a threat to system security.

⁸ At <https://www.aemo.com.au/energy-systems/gas/emergency-management/victorian-role>.

6.3.3 Administered price period

An administered price period will be invoked, under the Wholesale Market Administered Pricing Procedures⁹, if one or more of the following events occur:

- 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 6.3.4).

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.

In the event an Administered Price Period has caused a participant to be adversely impacted compensation can be claimed under the Wholesale Market Compensation Procedures⁸.

6.3.4 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 last 35 schedules (ie the current and preceding 34 schedules).

The cumulative price threshold is currently set at \$1,400, as per the Wholesale Market Administered Pricing Procedure⁸.

6.4 Gas schedules

Referring to Table 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 purple.
- Three gas schedules for the next gas day (d+1) at 8 AM, 4 PM, and 12 AM midnight – shown in light red.
- One schedule for the gas day after the next day (d+2) at 12 PM midday – shown in red.

⁹ At <https://www.aemo.com.au/energy-systems/gas/declared-wholesale-gas-market-dwgm/procedures-policies-and-guides>.

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.

Table 2 Gas market scheduling timelines

Scheduling inputs due					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 AEST.

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 6.5) 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.

6.5 Market participant inputs

Each MP submits the following input data, as applicable, for each standard schedule (see Section 6.4) for each gas day:

- Market bids— injection and controllable withdrawal bids—see Section 6.5.1.

- Demand forecasts—see Section 6.5.2.
- MPs submit the data via the WebExchanger in the MIBB.

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 6.5.3 for information about bid constraints.

6.5.1 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 9 shows the WebExchanger input screen for bid data.

Note: 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 10 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 9 WebExchanger Bid Set input screen



webExchanger

User: gmpag1
Participant: AGL Sales Pty Limited
Version: 37.0.1
Server time: Tue, 27/9/2022 1:32 pm
Database: NORTINPSQL3(CONS_BRZ:THM)

HomeBidsDemand Forecast

Menu

- Bid Selection

Actions

- Logout

Bid Set

Bid Set Id: <New Record>

Last User Id: <New Record>

Injection Meter: 30000001PC - Longford

Last Updated: <New Record>

From gas day: <New Record>

To gas day: <New Record>

Daily injection bids for fixed scheduling times. Bids must be entered at least 1 hour prior to time indicated.

6 AM

Steps: 12345678910

Price \$:

Daily Qty GJ:

10 AM

Steps: 12345678910

Price \$:

Daily Qty GJ:

2 PM

Steps: 12345678910

Price \$:

Daily Qty GJ:

6 PM

Steps: 12345678910

Price \$:

Daily Qty GJ:

10 PM

Steps: 12345678910

Price \$:

Daily Qty GJ:

Apply Bid To:

No Selection

Show Bid Row Copy

Submit Bid

6.5.2 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, gas generation and large refineries.
- The remaining system-wide uncontrollable withdrawals of their customers.

Figure 10 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.

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Figure 10 WebExchanger Demand Forecast input screen

6.5.3 Accredited bid constraints

Bid constraints must be accredited by AEMO, as per the Wholesale Market Accreditation Procedure¹⁰, 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.

¹⁰ At <https://www.aemo.com.au/energy-systems/gas/declared-wholesale-gas-market-dwgm/procedures-policies-and-guides>.

6.6 AEMO's inputs

AEMO's key inputs to the scheduling process include:

- AEMO's demand forecasts and demand forecast overrides (when required).
- Constraints which include supply and demand point constraints (SDPC), directional flow point constraints (DFPC) and net flow transportation constraints (NFTCs).
- End-of-day (EOD) linepack target.
- Intraday adjustments for injection or controllable withdrawals.
- Other relevant input data.

6.6.1 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 13.6.1 of this guide, the Wholesale Market Gas Scheduling Procedures¹¹, and the Demand Override Methodology¹⁰, for more details about how AEMO applies the override.

6.6.2 Constraints

Constraints that can be applied by AEMO are detailed in the Wholesale Market Gas Scheduling Procedure¹⁰.

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.

¹¹ At <https://www.aemo.com.au/energy-systems/gas/declared-wholesale-gas-market-dwgm/procedures-policies-and-guides>.

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 facility operators, including the terms and conditions of the operating agreements between AEMO and facility operators.

Directional flow point constraint

AEMO can also apply a directional flow point constraint (DFPC) to paired injection and withdrawal points on a pipeline such that a net direction of flow can be enforced for that bi-directional point 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 facility operators, including the terms and conditions of the operating agreements between AEMO and facility operators.

Net flow transportation constraint

AEMO can apply a net flow transportation constraint (NFTC) to a group of injection and withdrawal points on a pipeline such that the net injection or withdrawal flow from the grouped meters can be limited to the physical capacity of the DTS pipeline. 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.

AEMO sets the NFTC parameters according to the pipeline capacity limits identified by the Victorian Gas Planning Report.

Supply source constraint

AEMO can apply a supply source constraint (SSC) to injection bids registered at a particular production facility. Maximum hourly and maximum daily constraints can be specified for the production facility, which are taken into account when scheduling injection bids for the registered production facility in the next schedule.

AEMO sets the SSC parameters according to the production facility capacity limits identified by the Production facility operator.

6.6.3 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 430 TJ in summer and 460 TJ in winter. AEMO might change this target from time to time if considered necessary to maintain efficient and safe system operational conditions.

6.6.4 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.

6.6.5 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.

6.7 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.

6.7.1 Pricing schedules

The Pricing Schedule (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.

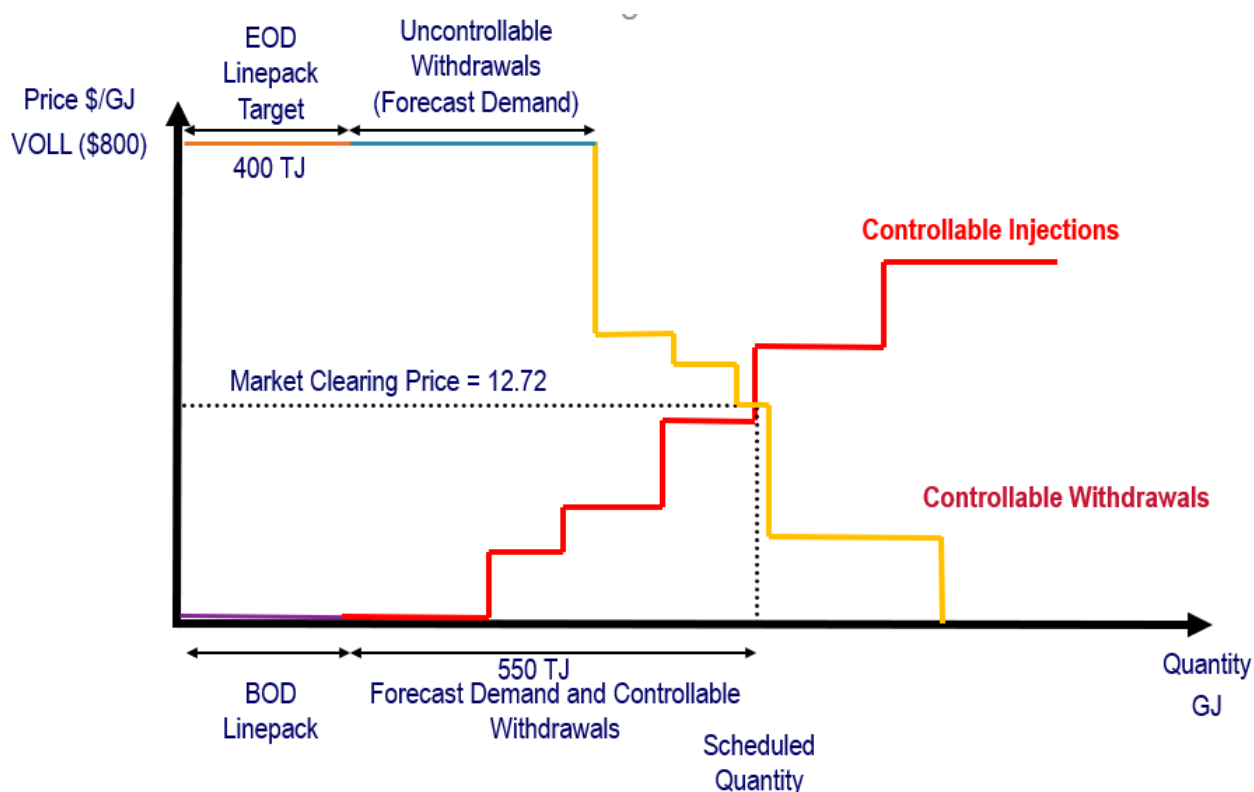
Figure 11 illustrates how the market price is determined. The example assumes that:

- The BOD and EOD linepack are equal (400 TJ).
- 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 \$12.72/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 11 Determining the market price



6.7.2 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 12.

Table 3 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.
- Purple (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.

Table 3 Standard schedules and scheduling intervals

Schedule (s)	Scheduling interval (i)				
	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					

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

6.8 Tie-breaking in gas schedules

A tie-breaking event is defined in the National Gas Rule 214, which specifies that:

“if two or more bids are equally beneficial for scheduling, a tie-breaking event occurs and AEMO must as far as practicable apply the following principles:

- Where two or more injection bids are equally beneficial, then those injection bids that are associated with entry capacity certificates should be scheduled before other injection bids that are equally beneficial and that are not associated with entry capacity certificates; and*
- Where two or more withdrawal bids are equally beneficial, then those withdrawal bids that are associated with exit capacity certificates should be scheduled before other withdrawal bids that are equally beneficial and that are not associated with exit capacity certificates.”*

A MP's tie-breaking rights are calculated in accordance with quantities of its entry capacity certificates allocated to each of the system injection points and exit capacity certificates allocated to each of the system withdrawal points in the Declared Transmission System that it intends and has been accredited to inject and withdraw gas from.

6.8.1 Determination of tie-breaking right

Capacity certificates provide MPs with priority rights for tied (equally priced) bids. Bids associated with capacity certificates will be scheduled ahead of those that are not associated with capacity certificates.

Tie-breaking rights are calculated:

- For each bid that are supported by capacity certificates.
- For each system point associated with in a capacity certificate zone. Some capacity certificate zone may only have one single system point while other capacity certificate zone may have multiple system points associated with them.
- Based on entry or exit capacity certificates which have been allocated to each MP at each capacity certificate zone.

6.8.2 Allocation of capacity certificates to bids example

MPs entry capacity certificate holdings will be associated with each bid step of their injection bids at all system injection points in a capacity certificate zone in order of increasing price bid to the extent of their entry capacity certificate holding and MPs exit capacity certificates holdings will be associated with each bid step of their withdrawal bids at all system withdrawal points in a capacity certificate zone in order of decreasing bid to the extent of their exit capacity certificates holdings.

The following example assumes:

- Participant A has entry capacity certificates of 300 GJ for capacity certificate zone C.
- Capacity certificate zone C has three system injection points (SIP1, SIP2 and SIP3).
- Participant A's injection bids are shown in Table 4.

Participant A's entry capacity certificate holdings are associated with each bid step of their injection bids at system injection points in the capacity certificate zone in order of increasing price bid. Participant A's injection of 20 GJ @ \$0.0600 at SIP1 does not have entry capacity certificates as their entry capacity certificates holdings have been used in up lower priced bids.

Table 4 Tie-breaking rights example

System injection point	Bid qty (GJ)	Bid price (\$/GJ)	Entry CC
SIP1	200	\$0.0000	Yes
SIP2	50	\$0.0500	Yes
SIP3	50	\$0.0560	Yes
SIP1	20	\$0.0600	No

The following example assumes:

- Participant E has exit capacity certificates of 100 GJ for capacity certificate zone H.
- Capacity certificate zone H has one system withdrawal point (SWP1 and SWP2).
- Participant E's withdrawal bids are shown in Table 5.

Participant E's exit capacity certificate holdings are associated with each bid step of their withdrawal bids at system withdrawal points in the capacity certificate zone in order of decreasing price bid. Participant E's withdrawal bid of 75 GJ @ \$800 at SWP1 and 50 GJ @ \$800 at SWP2 exceeds their exit capacity certificate holdings for the zone. The exit capacity certificate associated with the bid steps will be pro-rated according to the bid share. Withdrawal bid of 25 GJ @ \$50 at SWP1 does not have exit capacity certificates as they have been used in the higher priced bids.

Table 5 Allocation of capacity certificates to MP bids

System withdrawal point	Bid qty (GJ)	Bid price (\$/GJ)	Exit CC	Assign CC to bids
SWP1	75	\$800.0000	Yes – pro-rate	60
SWP2	50	\$800.0000	Yes – pro-rate	40
SWP1	25	\$50.0000	No	

6.8.3 Tie-breaking example

Capacity certificates provide MPs with priority rights for tied (equally priced) bids and bids associated with capacity certificates will be scheduled ahead of those that are not associated with capacity certificates.

The following example assumes:

- Participant A has entry capacity certificates of 300 GJ.
- Participant B has entry capacity certificates of 200 GJ.
- Participant C has entry capacity certificates of 100 GJ.
- Participant D has entry capacity certificates of 0 GJ.

SIP1 is supply constrained due to a plant issue. The facility operator has requested a constraint of 400 GJ. SDPC of 400 GJ is applied to both OS and PS. Available injection bids for SIP1 are shown in Table 6.

Since SIP1 injection is constrained down to 400 GJ, not all of these injection bids can be scheduled. The Market Clearing Engine (MCE) will remove the highest priced injection bid first, and then the second highest bid, until the cumulative injections are reduced to the constraint quantity.

Although Participant A's injection bid of 100 GJ @ \$1.0000/GJ has entry capacity certificates, it is not scheduled as it is the highest priced injection bid.

Participant A, B, C and D have equally priced injection bids at \$0.0000/GJ. Participant A, B and C's injection bid have entry capacity certificates while Participant D's injection bid does not have entry capacity certificates. Participant A, B and C's injection bids are scheduled before Participant D's injection bids. However, the total bid quantity from Participant A, B and C is more than the constraint of 400 GJ. The MCE will then tie-break their injection bids and pro-rate the participants according to their bid share. Participant A, B and C bid quantities are pro-rated to inject at SIP1.

Table 6 Tie-breaking rights example

Participant	Bid qty (GJ)	Bid price (\$/GJ)	Entry CC	Bid share (%)	OS qty (GJ)	PS qty (GJ)
A	200	\$0.0000	Yes	40	160	160
B	200	\$0.0000	Yes	40	160	160
C	100	\$0.0000	Yes	20	80	80
D	50	\$0.0000	No		0	0
A	100	\$1.0000	Yes		0	0
Total	650	-	-	100	400	400

7 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.

This chapter covers metering installations, the metering register and database, and conversion to energy.

For more information refer to the [Wholesale Market Metering Procedures](#)¹².

7.1 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.

The responsible person for a metering installation, is normally a distributor or the DTS SP (APA-GasNet) (unless otherwise agreed with the connected party). 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 7.2).
- 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.

7.2 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.

¹² At [AEMO | Procedures, policies and guides](#)

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

7.3 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.

7.4 Conversion to energy

Gas meters do not measure the commodity that is being sold, which is energy. Gas meters, dependent on the type of meter, will measure the volume or mass of gas at the conditions at the meter. This measured volume or mass must then be adjusted for pressure, temperature and compressibility effects to the equivalent volume at standard conditions. The adjusted (corrected) volume must then be multiplied by the heating value of the gas to obtain the energy measured.

The heating value of a gas is a measure of the energy released from its combustion. The heating value is determined by the composition of the gas and that in turn is determined by the geological formations the raw gas has come from and the operation of the plant used to process the raw gas. Changes in the raw gas source, the throughput of the processing plant and routine changes in plant processes all cause significant changes in the heating value of the processed gas. The hour-to-hour and day-to-day changes in heating value are inevitable.

The DTS currently has gas supply from 10 injection points that each have a gas chromatograph to measure gas quality including heating values, including at Longford Gas Production Facility, Lang Lang Gas Plant, Dandenong LNG storage and Iona Underground Storage, along with interconnected pipelines that can transport gas from Port Campbell region and South from Moomba and Queensland.

AEMO models the flow of gas within the DTS from these different gas supply sources through the Heating Value Allocation Model. This model allows the heating value of gas to be determined at each Custody Transfer Meter (CTM) or group of transmission CTMs where gas is withdrawn from the Declared Transmission System by customers. In determining the heating value AEMO grouped CTMs into heating value zones.

AEMO determines heating value zones at its discretion. Historically, the determination of heating value zones for each CTM or group of CTMs was done on the basis of the metering uncertainty limits required by NGR303(12). The metering uncertainty limits are specified in the Wholesale Market Metering Procedure. AEMO uses the Metering Uncertainty limits to calculate a derived Heating Value uncertainty limit¹³. AEMO developed the current heating value zones for the Declared Transmission System to ensuring the derived Heating Value uncertainty limit applied to each CTM was compliant with the derived Heating Value uncertainty limit.

AEMO, in consultation with Distribution Operators, then defined the postcodes serviced by each transmission CTM. However, postcodes are independent of gas flow boundaries in a distribution network and so one postcode may need to be split between two or more heating value zones. Postcode boundaries, while not perfectly suited to defining heating value zones, are considered to be adequate for the purpose. In addition they have the advantage that they provide an easily accessible and identifiable coding in the public domain.

¹³ Energy uncertainty squared equals the sum of the volume uncertainty squared and the heating value uncertainty squared as the volume and heating value uncertainties are independent, as per ISO 15112:2018 "Natural gas - energy determination".

8 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 9).
- Deviation quantities and payments (Chapter 10).
- Linepack account quantities and payments (Chapter 11).
- Ancillary quantities and payments (Chapter 12).
- Uplift quantities and payments (chapters 13).
- Market fees (see [National Gas Rules](#) Part 15A Division 3).

Figure 12 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.

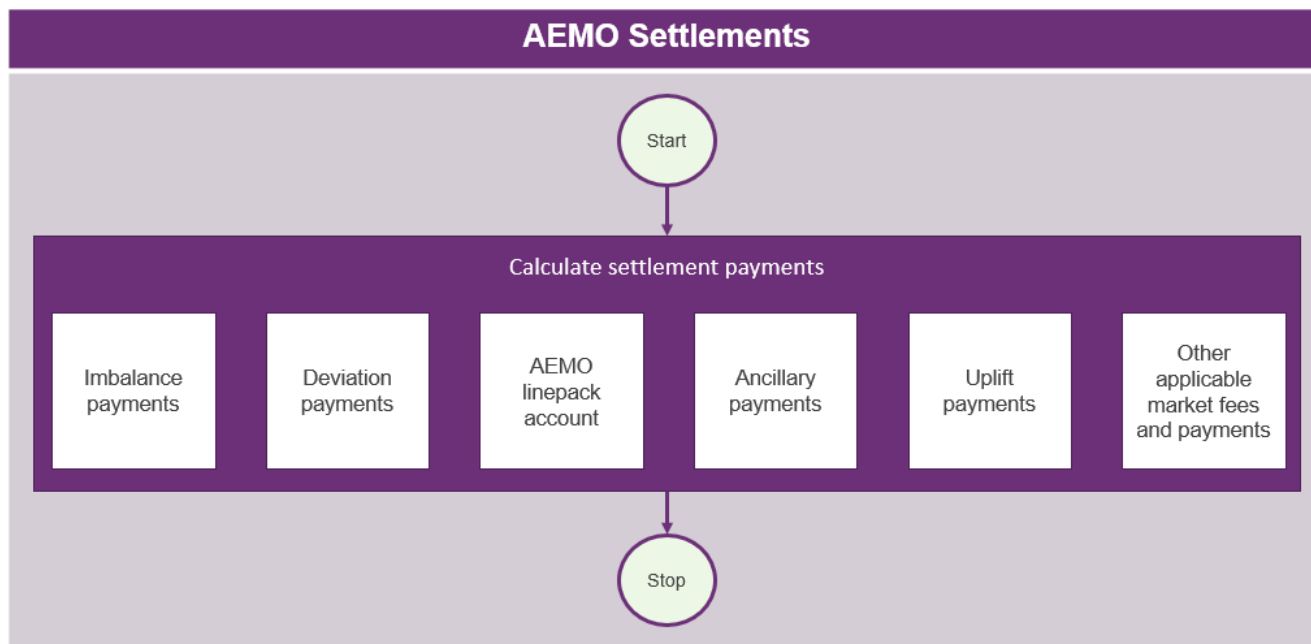
MPs are required to pay within 2 business days upon receiving the final settlement statement or a stated date for a revision statement. To assist MPs, AEMO calculates and issues various estimates of the final settlement amounts to each MP in the interim period. These include:

- 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 12 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 ”.

9 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).

9.1 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:

$$IP_1 = IQ_1 \times P_1 = (QWS_1 - QIS_1) \times P_1 \dots\dots\dots (1)$$

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

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

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

$$IP = \sum_s IP_s \dots\dots\dots (3)$$

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.

9.2 A worked example

Table 7 shows a simple example of the calculations of imbalance quantities and payments for a single MP.

Table 7 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	\$	
<i>S</i>	<i>QIS</i>	<i>QWS</i>	<i>P</i>	<i>IQ</i>	ΔIQ	<i>IP</i>	
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 (*QIS₁*) and withdraw 142 GJ (*QWS₁*) of gas in the 6 AM (*s*=1) schedule, resulting in a negative imbalance quantity of -19 GJ (*IQ₁*). The market price is 6.50 \$/GJ (*P₁*). 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 (*QWS₂*), but the scheduled injections (*QIS₂*) are unchanged at 161 GJ. The market price is 5.60 \$/GJ (*P₂*). Applying Equation 2, the IP is calculated by:

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

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 (*QIS₃*), but the scheduled withdrawals (*QWS₃*) are unchanged at 139 GJ. The market price is 4.50 \$/GJ (*P₃*). Applying Equation 2, the IP is calculated by:

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

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.

10 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.

10.1 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:

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

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.

10.2A worked example

Referring to Equation 4, the expression $QWS_s(i=s)$ is illustrated in Table 8, 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 8 Scheduled withdrawal quantities used in calculation of deviation payments

<i>QWS</i>		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 9, 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 9 Calculation of deviation payments

Schedule (s) and interval (i)	Actual withdrawal (GJ)	Scheduled withdrawal (GJ)	Actual injection (GJ)	Scheduled injection (GJ)	Net deviation (GJ)	Market price (\$/GJ)	Next market price (\$/GJ)	Deviation payment (\$)
<i>s, i</i>	<i>QWA</i>	<i>QWS</i>	<i>QIA</i>	<i>QIS</i>	<i>DQ</i>	<i>P_s</i>	<i>P_{s+1}</i>	<i>DP</i>
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.

11 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.

11.1 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:

$$LPA_s = \sum_p IP_s(p) + \sum_p DP_s(p) \dots\dots\dots (5)$$

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

$$LPA = \sum_s LPA_s \dots\dots\dots (6)$$

11.2 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:

$$LPP_p = LPA \times \left(QWA_p / \sum_p QWA_p \right) \dots\dots\dots (7)$$

11.3A worked example

Table 10 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 7 and 10.1. In this case, the net LPA payment for the gas day is a deficit of \$3.50 (LPA).

Table 10 Calculation of linepack account

Market participant A		Market participant B		Total			Linepack account payment (\$)	See equation
Schedule	Imbalance payment (\$)	Deviation payment (\$)	Imbalance payment (\$)	Deviation payment (\$)	Imbalance payment (\$)	Deviation 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 11, 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 11 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.

12 Ancillary payments

As discussed in Section 6.7, 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.

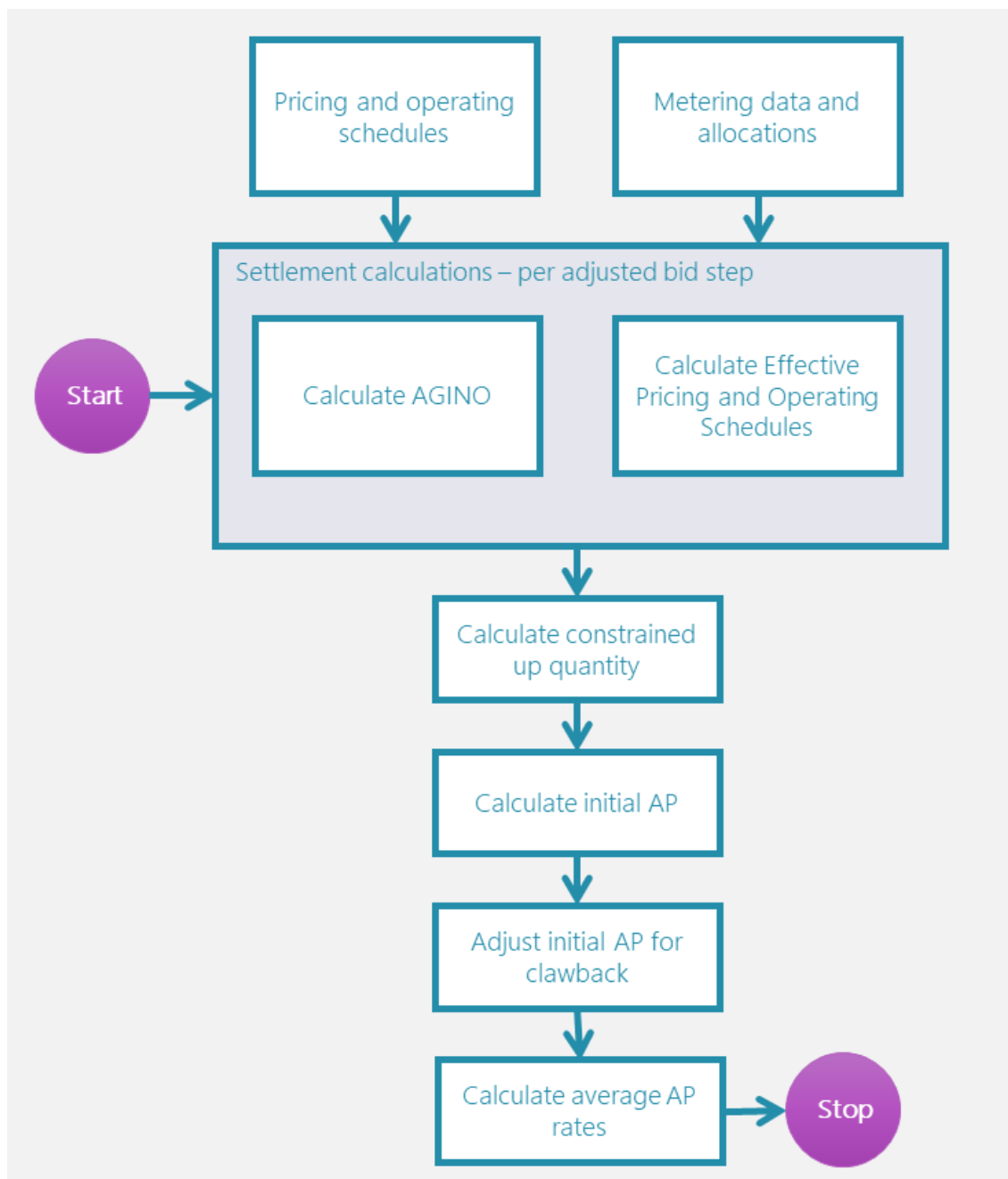
For more information, refer to [Wholesale Market Ancillary Payment Procedures](#) and [National Gas Rules](#).

12.1 Overview of ancillary payment calculations

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

- Determining the adjusted bid steps for the effective operating and pricing schedules.
- Calculation of initial APs (see Section 12.2).
- Adjusting the initial APs for AP clawback (see Section 12.4).
- Calculating the average ancillary payment rates (see Section 12.5).

Figure 13 Ancillary payment calculations



12.2 Adjusted bid steps and effective operating and pricing schedules

The pricing and operating schedules for each schedule for each system point are adjusted so that each has identical bid quantities. This enables the impact of changing bid prices during the day to be considered. This is shown in Figure 15, where each schedule now has an identical number of adjusted bid steps.

Figure 14 Bid stack

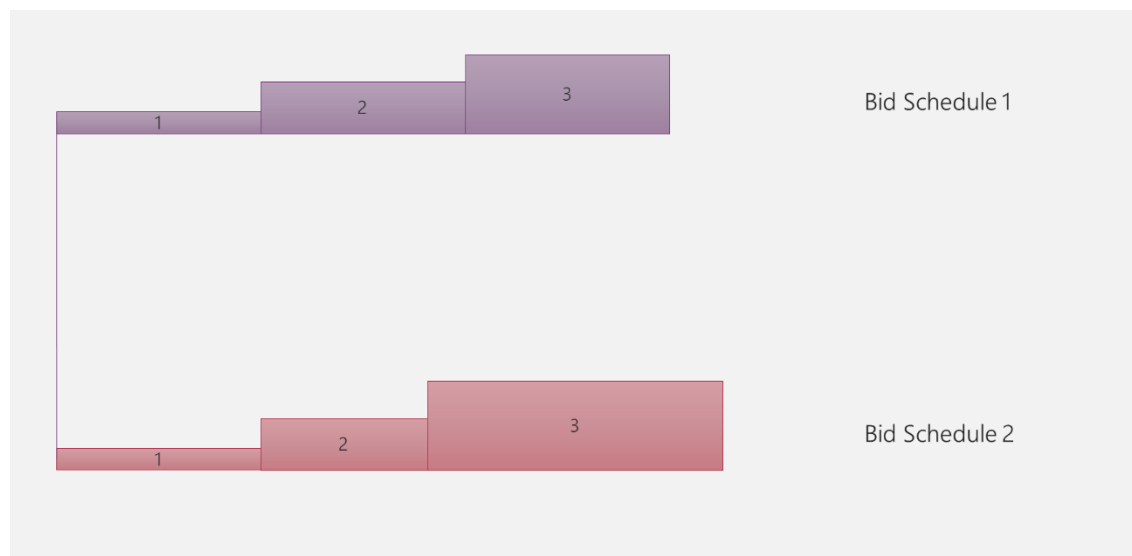
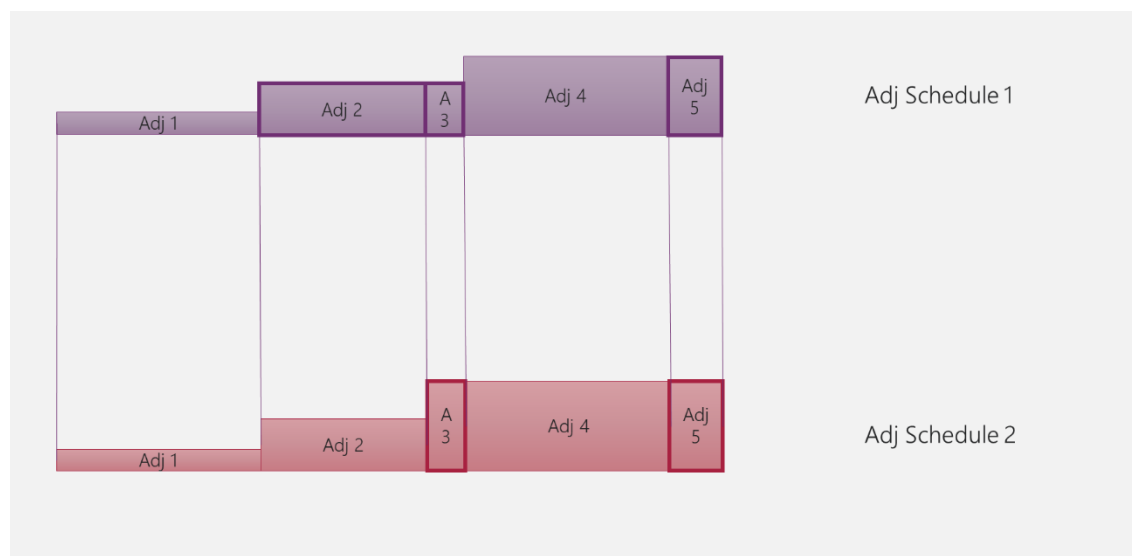


Figure 15 Adjusted bid steps



The scheduled quantity is then assigned to each adjusted bid step in turn, which then become the effective operating schedule and effective pricing schedule in Figure 16.

Figure 16 Effective schedule

12.3 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 and the Ancillary Payment Procedures.

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 12.3.1)

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

$$IAP_1(k) = CUIQ_1 \times \text{MAX}(0, b_1(k) - P_1) \dots\dots\dots (8)$$

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:

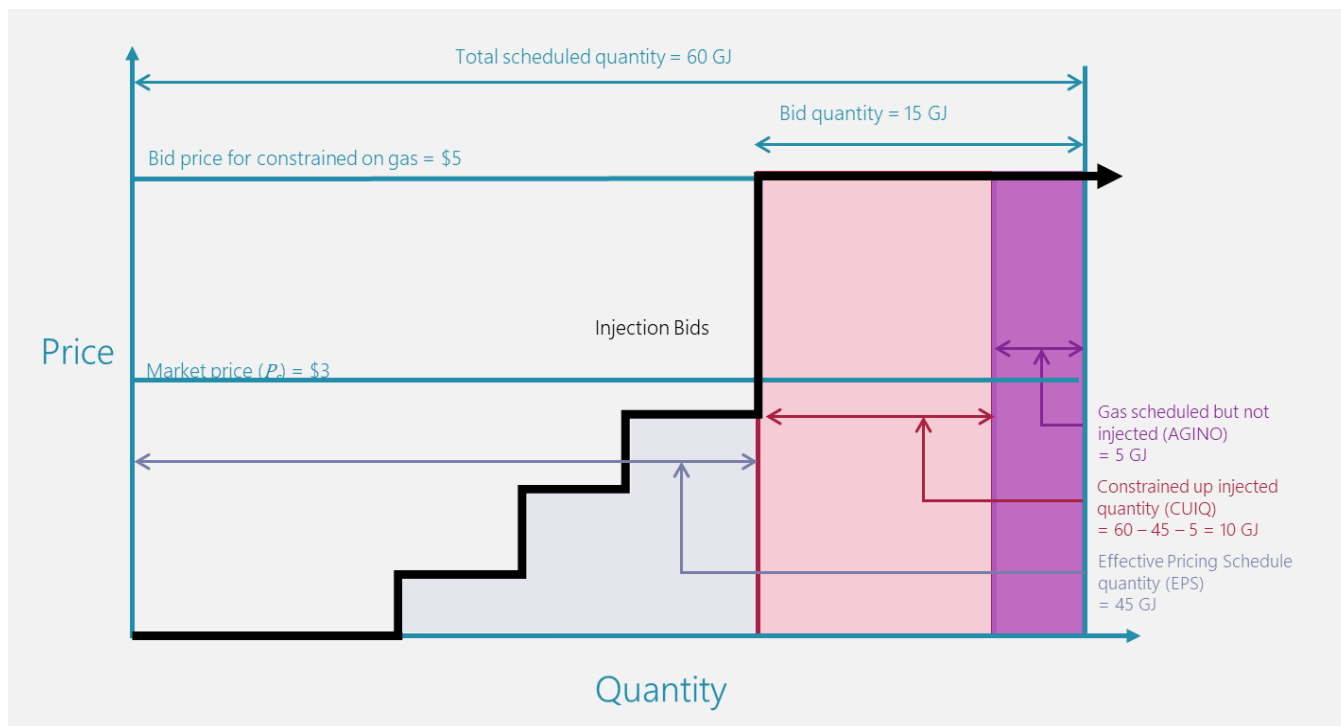
$$IAP_s(k) = (CUIQ_s - CUIQ_{s-1}) \times \text{MAX}(0, b_s(k) - P_s) \dots\dots\dots (9)$$

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 12.3.4 for more details about negative APs.

12.3.1 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 pink shaded area in Figure 17).

Figure 17 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 12.3.2)

EPS is the Effective Pricing Schedule in GJ

The CUIQ is calculated by:

$$CUIQ_s = QIS_s - AGINO_s - EPS_s \dots\dots\dots (10)$$

12.3.2 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:

$$AGINO_s(k) = \text{MAX}(0, QIS_s(k) - QIA_s(k)) \dots\dots\dots (11)$$

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

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

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

The example in Table 12 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 12 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 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 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.

$$\text{Min}QIS_s = \text{MIN}(QIS_s, QIS_{s+1}, \dots, QIS_{s=final}) \dots\dots\dots (13)$$

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.

$$AGINO_{s < final} = AGINO_{s=final} - (QIS_{s=final} - MinQIS_s) \dots \dots \dots (14)$$

Table 14 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 14 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 (GJ)	Equation 10	10	5	5	5	5

12.3.3 A worked example of initial ancillary payments

Table 15 shows an example of the calculations of the initial AP for the BOD schedule for each adjusted bid step. Referring to the columns (A, B, C, and so forth) in Table 16, the calculations are based on the following equations:

Table 15 Components of ancillary payment calculations

Column	Parameter	Explanation	Refer to
A	QIS	Scheduled injection quantity	Section 12.2
B	AGINO	Actual gas injection negative offset	Section 12.3.2
C	EPS	Effective pricing schedule quantity	Section 12.2
D	CUIQ	Constrained-up injection quantity $D = \text{MAX}(0, A - B - C)$	Section 12.3.1, Equation 10
E	Bid step price		
F	Market price		
G	AP price	$G = \text{MAX}(0, E - F)$	Section 12.2, Equation 8 (part)
H	Initial AP	$H = G \times D$	Section 12.2, Equation 8

In this example, the total scheduled quantity is 30 GJ. 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 16 Calculation of ancillary payments

Bid step	QIS (GJ)	AGINO (GJ)	EPS (GJ)	CUIQ (GJ)	Bid price (\$/GJ)	Market price (\$/GJ)	AP price (\$/GJ)	IAP (\$)
	<i>A</i>	<i>B</i>	<i>C</i>	<i>D</i>	<i>E</i>	<i>F</i>	<i>G</i>	<i>H</i>
1	5	0	5	0	3.00	3.10	0.00	0.00
2	15	0	0	15	5.10	3.10	2.00	30.00
3	10	5	0	5	7.10	3.10	4.00	20.00

12.3.4 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 12.2), 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 due to changes to schedules.
- Negative AP due to rebidding.
- Negative AP due to reduced rebid quantity.

Positive to Negative AP

The example in Table 17 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 2.50 \$/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.

Note that the initial AP changes sign from positive in the first schedule to negative in the second schedule.

Table 17 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

AP clawback type I

See Section 12.4 for more details of the AP clawback algorithm.

The example in Table 18 illustrates the situation where a negative AP occurs because the MP rebids its gas higher in the reschedule. Compared with the example in Table 17, 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 17. 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 18 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	

Bid	1	2	Total
IP (\$)	35.00	–30.00	5.00
AP (\$)	15.00	–70.00	–55.00
Total IP + AP (\$)	50.00	–100.00	–50.00

AP clawback type II

See Section 12.4 for more details of the AP clawback algorithm.

The example in Table 19 illustrates the situation where a negative AP occurs because the MP rebids a lower gas quantity in a later schedule. Compared with Table 17, 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 17. 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 de-scheduled 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 19 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

12.4 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 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 0 “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 0 “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 12.2. 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

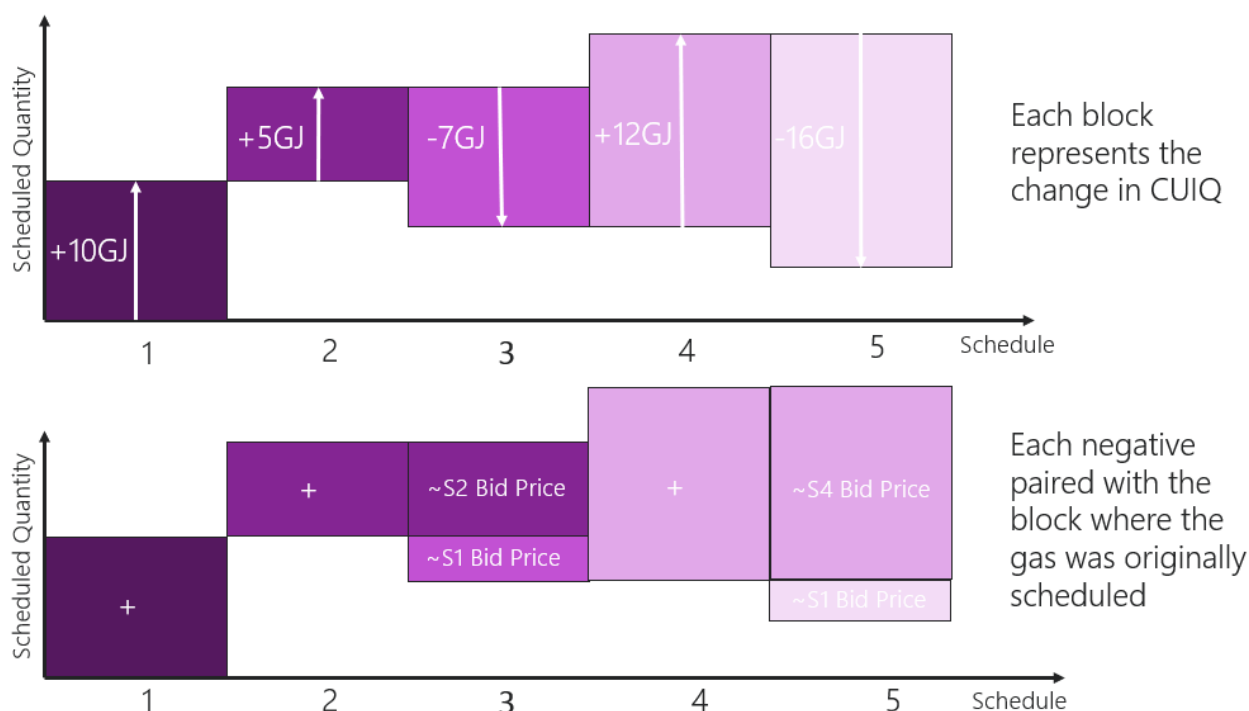
Calculate the revised AP for schedules with a negative initial AP for bid steps not associated with reduced rebid quantity (the AP clawback algorithm). For all other non-flagged bid steps, the negative AP is recalculated, by using the lesser (or the greater for a withdrawal) of bid price 1 and bid price 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 18 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 18 Matching bids for clawback pricing

In the top diagram in Figure 18, 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.

12.4.1 An example of AP clawback

Table 20 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 EPS is zero for all schedules. The CUIQ is therefore equal to the OS quantity.

Table 20 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	

	6 AM	10 AM	2 PM	6 PM	10 PM	Total daily
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 unforeseen 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

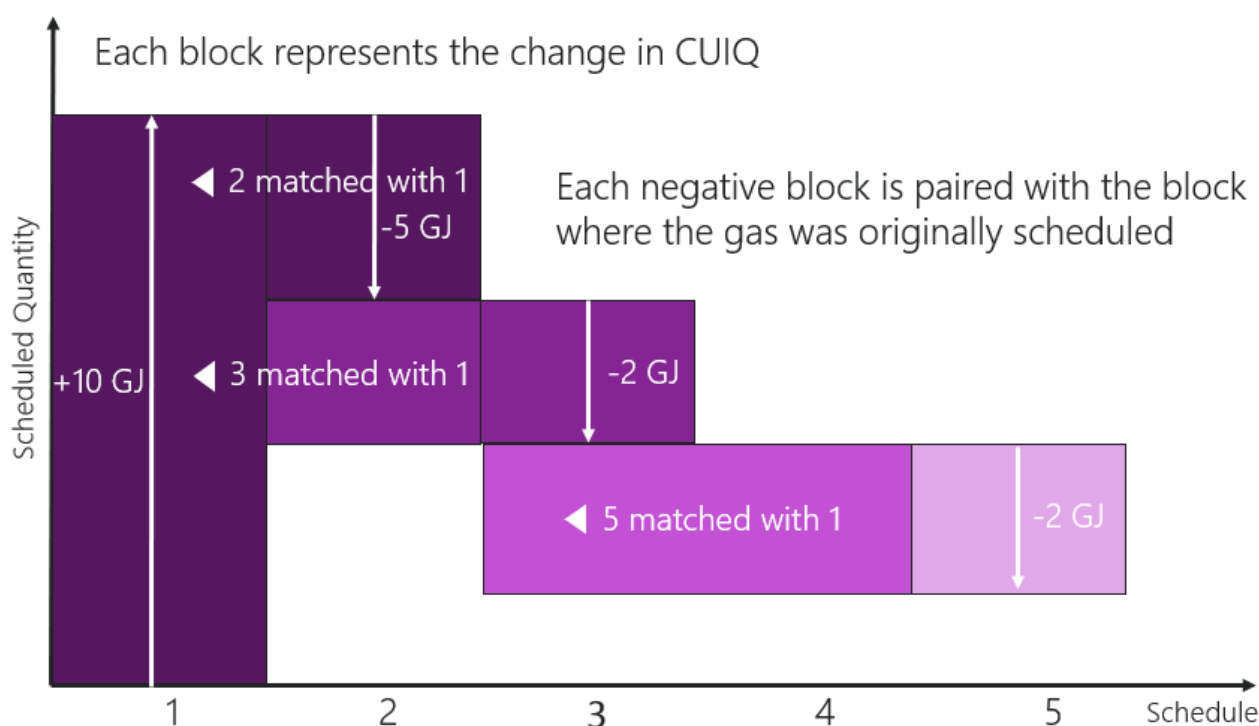
The bid step in the last schedule with the reduced rebid quantity is flagged.

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 19), 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 19), 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 19 Example of matching bids for clawback pricing



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

Referring to Table 20, the revised AP for the 10 PM schedule is $-\$4$, which is calculated by:

10 PM schedule AP clawback

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

Step 4 — Revise remaining negative initial APs

Referring to Table 20, 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

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

2 PM schedule AP clawback

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

Step 5 — Adjust revised APs

Following on from the example in Table 20 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 12.4). This is illustrated in Table 21.

Table 21 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 20 – 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 GJ, 21 GJ) = 7.38 \$/GJ).
- The reinstated AP equals the AP rate multiplied by the change in CUIQ (= 7.38 \$/GJ × -5 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 \$/GJ × -5 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)

12.5 Average AP payment rates

The average AP payment rates are calculated for each operating schedule for reporting and uplift payment purposes and will either be a positive average AP rate (PAVAPR_s) or a negative average AP rate (PAVAPR_s).

They are calculated as the sum of the positive (or negative) AP amounts divided by the sum of the positive (or negative) constrained up/down quantities.

Both positive and negative AP rates are positive \$ per GJ

For more information see *Wholesale Market Ancillary Payment Procedures* section 8.

13 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 (DTS SP) 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 [Wholesale Market Uplift Payment Procedures](#) and [National Gas Rules](#).

13.1 Overview of uplift payments

Total uplift payment amount

The total of the UP amount will equal the total of the AP amount for each gas day, but the Total UP amount per schedule (TUP_s) will be adjusted for the AP reallocation (flip-flop) methodology as described in Section 13.2 below.

The Total UP quantity per schedule will be determined using the Total UP amount divided by either the Positive Average AP rate (for positive Total UP amounts) or negative average AP rate (for negative Total UP amounts) for the schedule.

Uplift payment categories

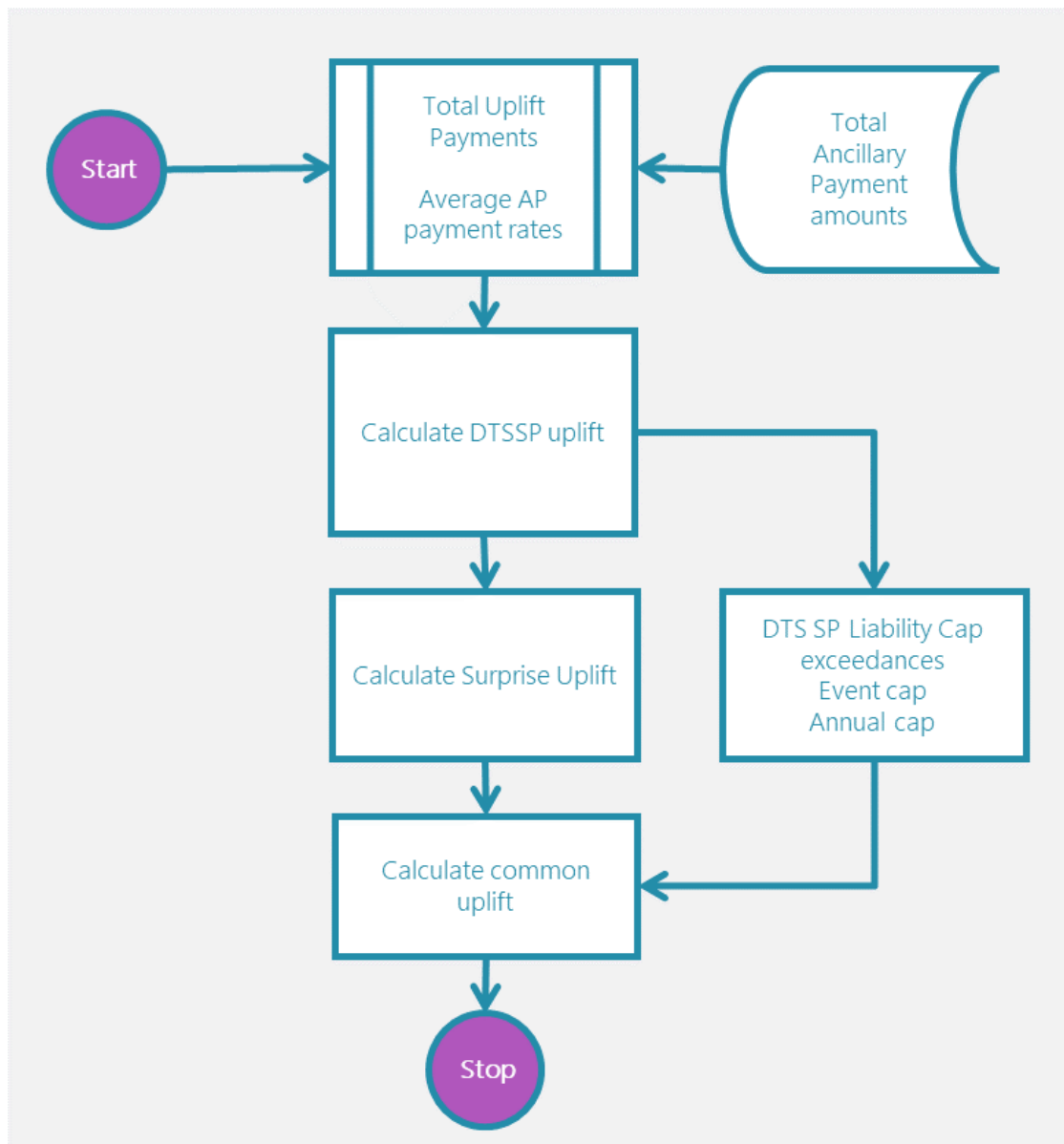
There are five categories of uplift payments:

- **DTS SP uplift.**
 - DTS SP uplift occurs when a transmission constraint is applied by AEMO in an operating schedule where the DTS SP has failed to fulfil its obligations under the Service Envelope Agreement (SEA). For example, this could be due to 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.
- **DTS SP event liability cap exceedance uplift.**
 - DTS SP event liability cap exceedance uplift is allocated to the DTS SP where the aggregate payment rate (\$ per GJ) over the gas day for DTS SP uplift exceeds the event cap in the SEA. It is always a payment to the DTS SP, and the payment will be added to the common uplift category and allocated to all MPs.
- **DTS SP annual liability cap exceedance uplift.**
 - DTS SP annual liability cap exceedance uplift is allocated to the DTS SP where the total payment in a calendar year for DTS SP uplift exceeds the annual cap in the SEA. It is always a payment to the DTS SP, and the payment will be added to the common uplift category and allocated to all MPs.
- **Surprise uplift.**
 - Where there is residual total UP quantities after allocation of DTS SP uplift quantities, 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 scheduling horizon.
- **Common uplift.**

- Common UP includes uplifts that cannot be fully recovered by other uplift payment categories plus all DTS SP liability cap exceedances. These costs are apportioned to MPs who withdraw gas on the relevant gas day.

Figure 20 shows the process for calculating uplift payments.

Figure 20 Calculation of uplift payments



The key input data to these calculations include:

- Ancillary payments (see Chapter 12).
- Operating and pricing schedules.
- Bid stacks for each Market Participant.
- Actual injections and withdrawals.

13.2 Calculating total uplift Payments (the AP redistribution algorithm)

The NGR require that the total of all uplift payments (UP) must equal the total of the AP. Because the AP may fluctuate between positive and negative values, the AP redistribution (or flip flop) algorithm is applied to minimise the swings in total market UP from schedule to schedule while not changing the total APs paid to each MP over the gas day. To the extent possible, the redistribution algorithm systematically cancels out negative APs with related positive APs to minimise the fluctuations in uplift amounts.

The AP payable by or to market participants are not adjusted in this process. This is only used to determine the total uplift payments to be recovered.

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 algorithm involves 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).

13.2.1 An example of AP flip-flop

Table 22 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 UP 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 22 Example of total uplift payment using 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 (adjusted for AP flip-flop step 2) (TAAP)	0	0	–\$300	\$200	\$0	–\$100
Final UP (adjusted for AP flip-flop step 3) (TUP)	\$0	–\$100	–\$200	\$200	\$0	–\$100

13.3 DTS SP uplift

DTS SP uplift is allocated to the DTS SP for any shortfall in system capacity due to a breach of the Service Envelope Agreement (SEA) which causes uplift payments for the schedule. 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.

Note that DT SP uplift is only allocated to the extent that the DTS SP uplift event has resulted in uplift payments and will not include uplift payments caused by other factors.

For transparency, note that DTS SP uplift includes any amounts that may be refunded to the DTS SP where either the event liability cap or the annual liability cap have been exceeded. This highlights the impact of the DTS not being available to the SEA capacity because of the DTS SP uplift event.

AEMO determines the capacity that should have been available for that schedule using the Common Model and the initial conditions applicable to that gas day and schedule.

13.3.1 Constraints

Where AEMO has decided that a DTS SP uplift event has occurred, the first step is to use the common model to determine the capacity that should have been available under the initial conditions for that gas day and schedule.

The common model is a modelled representation of the declared transmission system agreed between AEMO and the DTS SP under the service envelope agreement as may be updated from time to time to reflect changes to the DTS

13.3.2 SEA schedules

AEMO uses the capacities determined by the common model to set the constraints that should have applied had the DTS been operating at SEA capacity to calculate an SEA pricing schedule and an SEA operating schedule. All other constraints and inputs to the scheduling calculation are unchanged.

For example, where a compressor failure is deemed to be DTS SP uplift event, the actual schedules would have been produced using a transmission constraint reflecting capacity without the compressor. AEMO calculates the SEA schedules using a transmission constraint that reflects the capacity that should have been available under the same conditions but where the compressor was available.

AEMO manually calculates the SEA schedules using off-line scheduling software and provides the results for settlement calculations. SEA schedules are calculated for the first affected schedule in a gas day and for all subsequent schedules in that gas day.

For example, if the DTS SP uplift event occurred in schedule three, SEA schedules would be calculated for schedules three, four and five.

13.3.3 SEA Ancillary quantities

AEMO settlements uses the SEA schedules to calculate the SEA ancillary quantity that would have resulted had the DTS SP event not occurred. The calculations are set out in section 4 of the Uplift Payment Procedures.

The SEA ancillary quantities are calculated as the difference between the quantities scheduled for each hour in the operating schedules and the pricing schedules for each system point – see the Uplift Payment Procedures for full details.

Note that the SEA ancillary quantity *includes* other ancillary quantities that may still apply to that SEA schedule – for example ancillary payment quantities calculated because of an unrelated constraint applied at an injection point. In most – but not all – DTS SP uplift events it is unlikely that there will be other ancillary quantities.

13.3.4 DTS SP uplift quantities and amounts

DTS SP uplift quantities are the difference between the total uplift quantity and the SEA ancillary quantity for that gas day and schedule.

Because the total uplift quantity has been adjusted through the AP reallocation algorithm, the total uplift quantity may be less than the SEA ancillary quantity. The formula limits the DTS SP uplift quantity to no more than the total uplift quantity.

The uplift procedures set out the circumstances where AEMO must calculate a zero DTS SP uplift quantity:

- (i) When AEMO has not determined that a DTS SP uplift event occurred; or
- (ii) When AEMO has determined that a DTS SP uplift event has occurred and where:
 - (A) The operating schedule is before the first affected operating schedule in a gas day; or
 - (B) The total uplift payment quantity for the operating schedule is zero or negative; or
 - (C) SEA operating schedules and SEA pricing schedules for all affected operating schedules are not available.

AEMO calculates the DTS SP uplift amounts as the DTS SP uplift quantity multiplied by the positive ancillary payment rate for the schedule.

DTS SP uplift amounts are only positive uplift amounts – ie a payment from DTS SP to AEMO.

13.4 DTS SP event liability cap exceedance uplift

The maximum limit on DTS SP uplift per event is specified in the Service Envelope Agreement. If these limits are exceeded, a DTS SP event liability cap uplift amount will be paid to the DTS SP to compensate for the exceedance and will be added to the common uplift category.

DTS SP event liability cap exceedance uplift only applies where a positive DTS SP uplift exists.

AEMO calculates the DTS SP event liability cap exceedance uplift amount for a gas day and schedule as the difference (where negative) between the applicable event cap rate and the positive ancillary payment rate

multiplied by the DTS SP uplift quantity. Where the difference is positive, no DTS SP liability cap exceedance is payable.

The DTS SP event liability cap exceedance uplift quantity is estimated as the DTS SP event liability cap exceedance uplift amount divided by the positive ancillary payment rate.

Example

DTS Uplift quantity	FinalQDs	12,500GJ
Positive ancillary payment rate	PAVAPRs	26.53 \$/GJ
Event Cap rate	event cap	25.00 \$/GJ
DELCS	=	FinalQDs * (Min [0, (event cap – PAVAPR)])
	=	12,500 * (Min [0, (25.00 – 26.53)])
	=	12,500GJ * -1.53 \$/GJ
	=	- \$19,125 (ie payment to DTS SP)
DQELCS	=	DELCS / PAVAPRs
	=	-\$19,125 / 26.53 \$/GJ
	=	-720.882 GJ

DTS event liability cap exceedance amounts are always zero or negative indicating a payment from AEMO to the DTS SP provider and cannot refund more than the DTS SP uplift payment amount. The payment to DTS SP will be added to the Common Uplift category.

13.5 DTS SP annual liability cap exceedance uplift

The maximum limit on DTS SP uplift per calendar year is specified in the Service Envelope Agreement. If these limits are exceeded, a DTS SP annual liability cap uplift amount will be paid to the DTS SP to compensate for the exceedance and will be added to the common uplift category.

DTS SP annual liability cap exceedance uplift for a gas day and schedule only applies where a positive DTS SP uplift exists for that schedule. It is only determined after the DTS SP uplift and DTS SP event cap liability exceedance uplift have been calculated for that schedule.

The first step in calculating the DTS SP annual liability cap exceedance uplift amount for a gas day and schedule is to calculate the Prior annual liability cap (ALC) amount as the sum of the DTS SP uplift amounts, DTS SP event liability cap exceedance uplift amounts and DTS SP annual liability cap exceedance uplift amounts for all prior schedules.

The next step is to calculate current ALC amount as the sum of the DTS SP uplift amount and the DTS SP event liability cap exceedance uplift amount for the current schedule.

The final step is to calculate the DTS SP annual liability cap exceedance amount as the minimum of zero and the sum of the annual cap minus the prior ALC amount minus the current ALC amount.

Table 23 All DTS SP events in 2022 (example)

Gas Day	Schedule	D_UPs	D_ELCs	Prior ALC amt	Curr ALC amt	D_ALCs
3/01/2022	1	\$500,000	\$0	\$0	\$500,000	\$0
3/01/2022	2	\$400,000	-\$25,000	\$500,000	\$375,000	\$0
4/02/2022	4	\$50,000	-\$40,000	\$875,000	\$10,000	\$0
4/02/2022	5	\$30,000	-\$10,000	\$885,000	\$20,000	\$0
6/06/2022	3	\$200,000	-\$5,000	\$905,000	\$195,000	-\$100,000

For 4 Feb 2022 schedule 5, the Prior ALC include all DTS SP uplift events from 1 Jan 2022 schedule 1 until 4 Feb 2022 schedule 4.

$$\begin{aligned}
 \text{D_ALCs} &= \text{Min}(0, (\text{Annual Cap} - \text{Prior ALC} - \text{Current ALC})) \\
 &= \text{Min}(0, (\$1,000,000 - \$885,000 - \$20,000)) \\
 &= \text{Min}(0, \$95,000) \\
 &= \$0
 \end{aligned}$$

ie the annual cap has not been exceeded and the DTS SP does not receive any payments (other than those for the event cap liability exceedances).

For 6 June 2022 schedule 3, the Prior ALC include all DTS SP uplift events from 1 Jan 2022 schedule 1 until 6 June 2022 schedule 2.

$$\begin{aligned}
 \text{D_ALCs} &= \text{Min}(0, (\text{Annual Cap} - \text{Prior ALC} - \text{Current ALC})) \\
 &= \text{Min}(0, (\$1,000,000 - \$905,000 - \$195,000)) \\
 &= \text{Min}(0, -\$100,000) \\
 &= -\$100,000
 \end{aligned}$$

ie the annual cap was exceeded by \$100,000 and the DTS SP received \$100,000.

The DTS SP annual liability cap exceedance uplift quantity is estimated as the DTS SP annual liability cap exceedance uplift amount divided by the positive ancillary payment rate.

13.6 Surprise uplift

An MP is liable for surprise uplift if the following conditions are true:

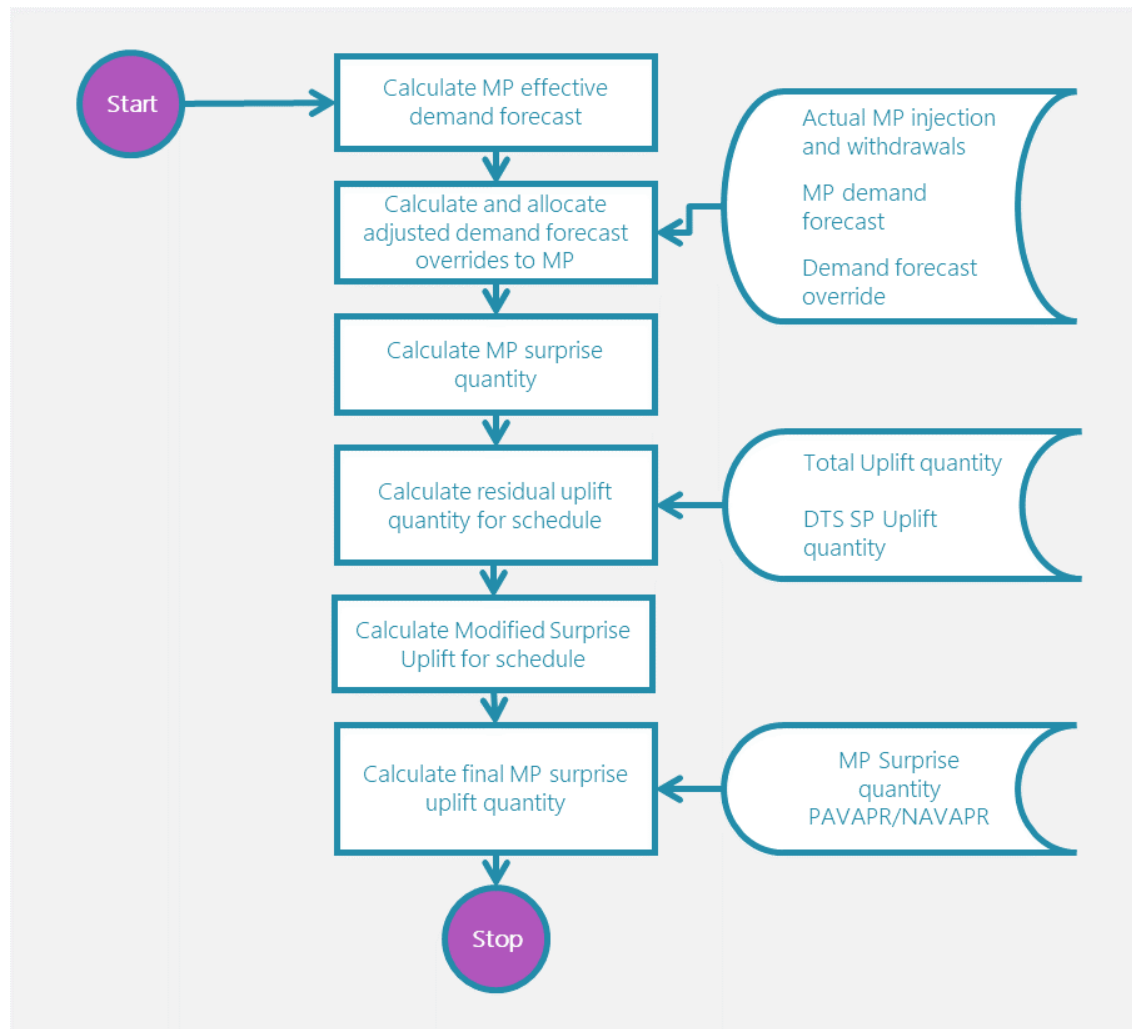
- There are residual uplift payment quantities after deducting DTS SP uplift quantities from the Total Uplift Quantities for the operating schedule; and

Note that the NGR requires that any liability cap exceedance amounts are recovered through the common uplift category, so the event and annual liability cap exceedance amounts are not factored into the residual uplift payment quantity.

- The MP deviates from its effective demand forecast quantities or scheduled controllable quantities in the previous scheduling interval; or
- An MP's effective demand forecast or scheduled controllable quantities for the current scheduling horizon are revised.

An MP's effective demand forecast is a combination of their demand forecast and any allocated AEMO demand forecast override – see below.

Figure 21 Surprise uplift process



13.6.1 Demand forecast overrides and effective demand forecasts

MPs with uncontrollable loads must submit hourly demand 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 surprise uplift quantities and do not affect 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](#) when applying overrides to MPs demand forecasts.

Calculating AEMO's adjusted hourly demand forecast overrides

Figure 21 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 24 Adjusted demand forecast overrides

Scheduling interval 6 AM – 10 AM	Hourly demand forecast deviation (GJ)	% of positive demand forecast override	Hourly demand forecast override (GJ)
	<i>A</i>	<i>B</i>	$C = A \times B$
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

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 25, 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 $C = \text{MAX}(0, B - A)$. 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 24). 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 25 Calculation of an MP's effective demand forecast

Scheduling interval hour	MP's demand forecast (GJ)	MP's actual uncontrollable withdrawal (GJ)	MP's demand forecast deviation (GJ)	Total demand forecast deviation (GJ)	MP's share of total demand forecast deviation (%)	AEMO adjusted demand forecast override (GJ)	Effective demand forecast (GJ)
	<i>A</i>	<i>B</i>	<i>C</i>	<i>D</i>	<i>E</i>	<i>F</i>	<i>G</i>
6 AM – 7 AM	10.0	10.3	0.3	0.3	100%	0.0	10.0
7 AM – 8 AM	8.0	7.5	0.0	0.8	0%	0.75	8.0
8 AM – 9 AM	7.0	8.2	1.2	2.0	60%	1.50	7.9
9 AM – 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 calculation's 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.

13.6.2 Surprise uplift quantity

For the first schedule of the gas day, the surprise uplift quantity for each MP 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:

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

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

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

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 26 shows calculations of surprise UP quantity (shown in column C). Injection deviations (column A) are those calculated previously in Table 9 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 27. Columns D and E show the calculated (positive and negative) surprise uplift quantities.

Table 26 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 9	From Table 27			

Table 27 Calculation of withdrawal deviations and change in demand forecasts

Scheduling interval (i)	Actual withdrawal	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 27, 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 28 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 13.

Table 28 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

13.6.3 Modified uplift quantity for a schedule

The sum of the surprise uplift quantities for all market participants is limited by the residual uplift payment quantity for that schedule, which is the total uplift quantity less any DTS SP uplift quantity.

Note that DTS SP uplift quantities are always zero where the total uplift quantity is negative.

An MP's final surprise quantity for a schedule is calculated as that MP's share of the modified surprise quantity in proportion to either their positive surprise uplift quantities or their negative surprise uplift quantities.

An MP's final surprise uplift amounts are calculated as the product of the MP's final surprise quantity and the relevant positive or negative average ancillary payment rate.

See the Uplift Payment Procedures section 7.4 for more details.

Any residual uplift payment quantity not recovered through modified surprise uplift quantities will be recovered through the common uplift category.

13.7 Common uplift category

The common uplift category for a gas day and schedule recovers any remaining uplift payment amounts from the total uplift amount after deduction of DTS SP uplift amounts and total MP final surprise uplift amounts, less the total of any liability cap exceedance amounts in that schedule. It is calculated after all other uplift categories for a schedule have been determined.

Because the liability cap exceedance amounts are negative, this means they are added to the common uplift category and recovered from all market participants (as is required by NGR 240.7). The mechanism for this is through the common uplift category.

The common uplift amount per schedule is recovered from MP's as their share of the total common uplift amount in proportion to their adjusted withdrawals from the DTS.

The common uplift quantity per schedule is calculated as the MP's common uplift amount divided by the relevant positive or negative average ancillary payment rate.

Glossary

Abbreviation	Term
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AEST	Australian Eastern Standard Time
AP	ancillary payment
CUIQ	constrained-up injection quantity
DFS	Demand Forecasting System
DP	deviation payment
DTS	Declared Transmission System
DTS SP	Declared Transmission System Service Provider
GJ	gigajoule is a unit of measure of energy equal to 10^9 joule
GRCF	Gas Retail Consultative Forum
GWCF	Gas Wholesale Consultative Forum
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
PJ	petajoule is a unit of measure of energy equal to 10^{15} joule
SCADA	supervisory control and data acquisition
TJ	terajoule is a unit of measure of energy equal to 10^{12} joule