AEMO
Draft FY25 Budget and Fees
April 2024

DRAFT FOR CONSULTATION

AEMO acknowledges the Traditional Owners of country throughout Australia and recognises their continuing connection to land, waters, and culture. We pay respect to Elders past and present.

This document sets out AEMO's draft budgeted revenue requirements and fees for the financial year ending 30 June 2025 (FY25), in accordance with clauses 2.11.3 and S6A.4.2 of the National Electricity Rules, clause 135CF of the National Gas Rules and clauses 2.22.7A and 2.24 of the Wholesale Electricity Market Rules.

This draft FY25 Budget and Fees is for consultation and AEMO will consider any feedback it receives before finalisation. The final FY25 Budget and Fees will be approved by AEMO's Board of directors.

The FY25 Budget and Fees is presented in nominal Australian dollars, net of goods and services tax and amounts have been rounded to the nearest hundred thousand dollars, unless otherwise stated. Financials presented are pre-consolidation of AEMO's subsidiaries (except where stated otherwise) and have been prepared consistent to generally accepted budgeting principles.

Foreword

Australia is in the midst of an accelerating energy transition as the nation prepares for a net-zero future. Combinations of renewable generation connected with new transmission, backed up by hydro, batteries, and gas, are replacing ageing coal-fired generators as they reach the end of their service life.

As Australia's independent system and market operator and system planner, AEMO's purpose is to ensure safe, reliable, and affordable energy, and enable the energy transition for the benefit of all Australians.

AEMO's responsibilities are expanding as we anticipate and respond to the challenges of the energy transition. This includes in our work supporting the roll-out of the Australian Government's Capacity Investment Scheme (CIS).

As we do this, we remain focused on enabling least-cost energy for consumers, through efficiency of our own operations and the way we plan for the energy systems and markets of the future.

AEMO remains committed to our stated objective of repaying the NEM Core accumulated deficit by the end of FY25, as we promised stakeholders in 2022. This will be challenging for AEMO as we continue to execute existing, new, and emerging responsibilities and manage the impact of economic conditions. Yet, we are committed to demonstrating financial discipline and continuing to build trust with our stakeholders.

Other new responsibilities include cyber security coordination responsibilities conferred on us by the Australian and state energy Ministers in late 2022, essential uplifts of our own cyber posture and investments in modern operational technology and digital business systems.

As Australia's energy transition progresses, AEMO must continue to deliver for consumers through our four priorities. Where it makes sense, this may mean AEMO's functions continue to evolve as we have experienced in recent years from providing tender services to NSW and the Commonwealth governments, to continuing to invest in cyber capabilities to ensure that AEMO (and, as a result, Australia) is as resilient as possible in the face of increasing cyber threats.

Included in this budget, for the first time, are the recovery of capital costs for NEM Reform and East Coast Gas Reform stage 1 projects that have been deployed and the costs of projects anticipated to deploy during FY25. These costs are reflected in the Depreciation and Amortisation of the NEM Functions and East Coast Gas segments, respectively.

I also acknowledge the substantial reforms AEMO's teams delivered for Western Australia's (WA) Wholesale Electricity Market (WEM), which were deployed on 1 October 2023, and which are now reflected in the operating budget for WA for the year ahead.

AEMO Services Limited (ASL) continues its critical role providing expertise and services to help transform Australia's energy sector, both as the New South Wales Consumer Trustee and supporting AEMO to deliver its Capacity Investment Scheme obligations. As a subsidiary of AEMO with an independent board, AEMO Services budget is determined under a separate process.

In Victoria, AEMO is fulfilling a range of functions specific to this segment and is progressing discussions with the Victorian government about the potential consolidation of transmission planning functions, including procurement, into one entity (VicGrid) to streamline and improve efficiency of the end-to-end process.

With our NEM Core deficit expected to be repaid by the end of FY25, AEMO will continue to accelerate its own transformation from FY26, to keep pace with the increasingly complex and expanded set of responsibilities to enhance the energy transition.

As we demonstrate through this budget, AEMO's strong financial management principles and discipline will continue to guide our work and remain a priority for AEMO's executive and Board.

I look forward to continuing to work with our stakeholders throughout FY25 and beyond to ensure safe, reliable & affordable energy and enable the energy transition for the benefit of all Australians.

Daniel Westerman

Chief Executive

Contents

1. Budget overview

AEMO is committed to improving the transparency of our operations and decision making, including our financial management. In this context, we are publishing a comprehensive draft budget and fees for FY25 for consultation and feedback.

AEMO is a not-for-profit organisation, operating on a full cost-recovery basis. To that end, AEMO's revenue requirement is determined by establishing efficient and prudent levels of expenditure associated with the functions and services it provides in each of the segments which it operates. Funding and fee structures for segments are different, with different fee payers relative to the function we perform. AEMO manages its functions across a number of segments based on the funding model for each segment. Costs incurred for each segment are recovered by fees paid by market participants, and applied according to the established fee structures for the relevant segment.

AEMO's FY25 budget sets out the costs of delivering our core functions and responsibilities, as well as the strategic priorities outlined in our corporate plan. It also includes ongoing investment in key capabilities that are essential for the secure and reliable operation of Australia's energy systems and markets, including substantial investment in digital services and cyber capabilities.

AEMO's capital investments and short-term working capital requirements are generally facilitated through debt financing. This enables capital costs to be recovered from market participants over the life of the asset, in accordance with the depreciation and amortisation (D&A) profile. D&A charges are growing, reflecting the delivery of significant reform programs in recent years. This trend will continue as further investment is required to transform the energy system and markets as we progress towards a net zero future.

The FY25 budget anticipates a full remediation of the deficit accumulated in NEM Core prior to FY23, consistent with the three-year deficit recovery pathway developed in consultation with stakeholders.

1.1. Budget scope

AEMO's annual budget and fee process establishes the annual revenue requirements for AEMO's core functions – National Electricity Market (NEM) Core, NEM Functions and East Coast Gas (ECG).

Budget and fees for other functions and segments are determined through alternative processes, as follows:

- National Transmission Planner (NTP) function, which was determined and published on 15 February 2024, in line with section 2.11.3 of the National Electricity Rules
- NEM Core participant fees for each Transmission Network Service Providers (TNSP) and notified them of their charges on 15 February 2024, in line with section 11.153.2 of the National Electricity Rules
- Gas Supply Hub fees are determined outside of AEMO's budget and fee setting process, through a consultation process and are set within the Gas Supply Hub exchange agreement
- AEMO's budget and fees for its WA Wholesale Electricity Market (WEM) and Gas Services Information (GSI) functions
- Victoria's Transmission Use of System (TUoS), which were published on 15 March 2024 and have been determined in accordance with Chapter 6A of the National Electricity Rules and AEMO's Pricing Methodology for Prescribed Shared Transmission Services
- AEMO Services Limited's (ASL's) independent board approves its funding arrangements and budget. ASL operates on a not-for-profit, full-cost recovery basis. ASL is a subsidiary of AEMO which carries out functions as appointed by National Electricity Market jurisdictions with specific funding arrangements

1.2. How the budget is developed

AEMO has established a rigorous planning methodology to assess and prioritise identified potential projects to produce an integrated investment plan that aligns to AEMO's key strategic initiatives.

This integrated investment plan is a key input to the budget process. The operating budget is also established with efficiency and cost-effective delivery the primary consideration to ensure AEMO carefully invest funds collected via fees and charges.

The resulting priorities and budget by segment are established by AEMO's executive management team, consistent with our financial principles (see figure 1). This is then converted into revenue requirements and fees for each segment.

The draft budget and fees document is prepared to provide transparency of AEMO's costs and fees for stakeholders' consideration, ahead of publication of the final document. Revenue requirements established outside of the annual budgeting process are included in the draft and final document to provide a comprehensive view of AEMO's financial position.

The draft budget and fee document provides a comprehensive view of AEMO's financial position, noting some revenue requirements are set through separate processes.

Stakeholders are invited to provide feedback on the draft budget and fees, both through AEMO's Financial Consultation Committee and a broader consultation and submission process. AEMO's management considers the feedback received during the consultation period prior to finalising the budget and fees document. AEMO's Board has accountability for approving the budget prior to 30 June 2024.

1.3. How fee structures and rates are developed

AEMO recovers its revenue requirements from registered participants according to the relevant fee structures for each function. In summary, the fee structures determine the proportion of revenue to be paid by each type of registered participant and on what basis the fee will be allocated, for example $/MWh or $/NMI.

For both the NEM and East Coast Gas (ECG) segments, fee structures are determined by AEMO through review and consultation processes. Registered participants incur fees for the markets and services they are involved in.

The fee structures for the Western Australia's Wholesale Electricity Market (WEM) and Gas Services Information (GSI) functions are set through the regulatory and rule making process.

AEMO establishes new fee structures, in consultation with market participants, when it has major new responsibilities assigned, that incur additional costs. Establishing discreet fee structures creates transparency for market participants.

Figure 1. AEMO's financial principles

1.4. Financial governance and risk management

AEMO's Board is responsible for the overall governance of the company. As a member-based organisation funded by registered participants, we are committed to transparent and accountable financial and risk management.

AEMO has a range of governance mechanisms in place. The roles of each are outlined below:

The Board

The Board oversees AEMO's activities to ensure we meet our responsibilities under relevant laws and regulatory regimes. The Board monitors the performance and cost-effectiveness of, and risks associated with, AEMO's operations and systems. The Board is accountable to AEMO's members (60% federal, state and territory governments and 40% market participants). AEMO's Constitution and Board charter set out the full role and responsibilities of the Board.

Executive management team

AEMO's executive management team is made up of the CEO and executive general managers for each business division. Executive committees are established around key programs of work and functions. The committees are responsible for overseeing the implementation of strategic initiatives and key programs of work to achieve AEMO's vision and purpose, and that we are doing so effectively, collaboratively, efficiently and in accordance with our values and compliance obligations.

Finance and Governance team

AEMO's Finance and Governance team is led by the Executive General Manager for Finance and Governance. The team is responsible for establishing, maintaining, and improving AEMO's financial, risk and governance policies, procedures and systems, and for building the capability of staff in the areas of financial planning and performance, legal and regulatory obligations, corporate governance standards, and an effective risk and compliance culture. The finance team manages AEMO's finances in line with AEMO's financial principles and budget and publishes a statutory financial report each year.

Stakeholders

Stakeholders complement AEMO's governance framework by inputting to our work through many different groups, at different levels of participation. Stakeholder input helps us to do our work more effectively, to implement reforms more seamlessly, and to deliver better outcomes. Our stakeholder engagement groups vary in their focus from strategic direction, to sequencing delivery, budget, and expenditure; to more detailed planning relating to integrating reforms and system changes.

2. Budget by segments

AEMO's budget is structured around segments. Fees and charges are collected for each segment to recover the related costs incurred. The segments are:

National Electricity Market (NEM):
NEM Core
NEM Connections
NEM Functions

East Coast Gas (ECG)

WA: Wholesale Electricity Market (WEM) and Gas Services Information (GSI)

Victorian Transmission Network Service Provider (Vic TNSP)*

AEMO Services Limited (ASL)

Chart 1. FY25 Budget Operating expenditure by segment ($m)

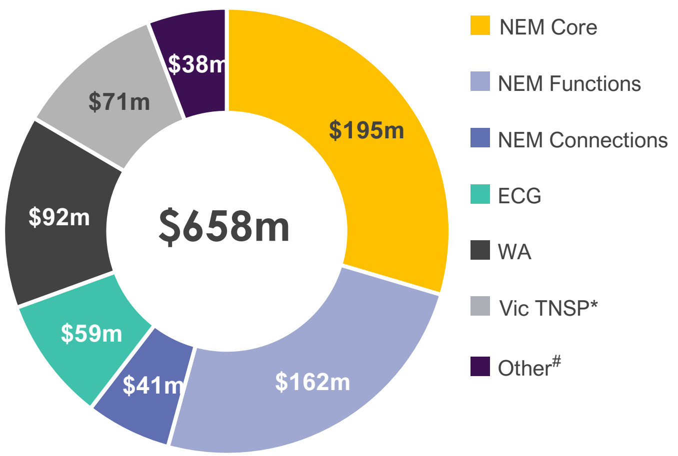
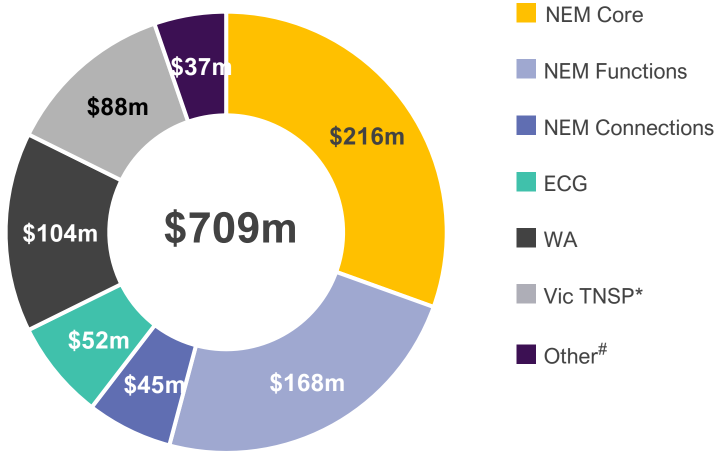


Chart 2. FY25 Budget Revenue requirement by segment ($m)



*Vic TNSP segment includes Transmission Corporation Victoria (TCV), a wholly owned subsidiary focused on accelerating the delivery of the VNI-West program.

#Other primarily represents cost and revenue for services provided by ASL. ASL is currently in the process of finalising its budget for FY25.

2.1. NEM Core

Purpose

Keeping the National Electricity Market (NEM) operating safely, reliably, and securely is AEMO's core work. This includes:

- ensuring power system security and reliability
- market operations and systems
- wholesale metering, settlements, and prudential supervision
- near-term energy forecasting and planning services

Read more about what AEMO does in this segment by referring to Segment, function and function purpose.

Participants

Participants in this segment include market customers, wholesale participants and Transmission Network Service Providers.

Fee structures that apply

- Electricity Fee Structures: March 2021

Segment health

In 2022 AEMO consulted with stakeholders with regards to remedying a NEM Core deficit of ~$100 million that had accumulated over several years due to revenue (fees) remaining static while expenses related to AEMO's core work increased. As a result, a three-year deficit recovery plan was established. This saw the NEM benchmark fee increase by 89% in FY23, with 4.5% increases planned in FY24 and FY25.

In FY23 and FY24 recovery of the accumulated deficit is ahead of schedule despite financial headwinds unforeseen when the deficit recovery fee pathway was set. Significant effort and progress has been made to find underlying efficiencies to counteract these additional costs, whilst managing increasing risks in operating the energy systems. We anticipate the 4.5% increase to NEM Core fees in FY25 will achieve the stated objective of full recovery of the accumulated deficit and ensure we have sufficient revenue to continue to provide essential, core services to the NEM.

Table 1 NEM Core profit and loss summary FY25

	Budget FY24* $m	Budget FY25 $m	Variance $m	Variance %
Revenue#	204.6	216.2	11.6	5.7
Operating costs	171.2	194.7	23.5	13.8
Annual surplus/(deficit)	33.4	21.5	(11.9)	N/A
Accumulated surplus/(deficit)	**(26.4)**	**0.0**	**26.4**	**N/A**

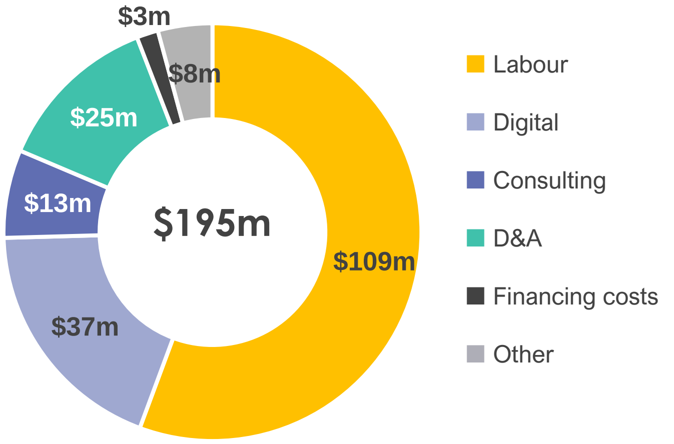
* FY24 financials have be adjusted to remove NEM registration costs and revenue from the above table for comparative purposes.

consists of NEM Core revenue requirement and other revenue

Segment investment

NEM Core represents the largest portion of spend for AEMO. Expenditure decisions reflect our regulatory responsibilities and requirement to meet market needs.

Chart 3. Budgeted operating cost profile for NEM core FY25 ($m)



Priority initiatives and investments in FY25

Priority initiatives and work contributing to costs in NEM Core include:

- core work relating to system and market operation
- improvements of cyber security in AEMO's core business and operating systems and industry cyber coordination planning and response activities
- project operating expenditure relating to the Operating Technology Roadmap
- implementation of actions from the Engineering Road map
- finance system (ERP) deployment, with associated Software as a Service (SaaS) / project expenditure

Labour

Labour is our biggest expenditure within NEM Core. AEMO over the past two years has deferred and prioritised recruitment to ensure that it can repay the accumulated deficit in the agreed three years ending FY25.

With the speed of energy transition increasing, to meet the challenges and mitigate operational risks, AEMO needs to uplift its workforce in FY25 by employing more skilled and experienced people to build our capabilities and capacity to resource highly complex programs of work.

Recruitment is occurring across the business to deliver the energy transition with focus primarily within system design, operations, and cyber resilience activities. Wage inflation (reflecting a tight labour market) is also a challenge.

Digital

As a responsible entity under the Security of Critical Infrastructure Act 2018, AEMO has a special role in protecting Australia's energy system from cyber threats. Continued investment is essential and crucial to enhance AEMO's cyber posture. Whilst costly, protecting Australia's energy sector from cyber threats is of national importance and investment in FY25 reflects our pivotal role as a market co-ordinator facing increasing risks.

In FY25 AEMO is investing in its corporate systems, such as enterprise resource planning and project management (deferred from FY24). This investment will improve the effectiveness and efficiency of our financial governance. An increasing portion of technology costs are operating expenditure in nature rather than capital expenditure, as we move to software-as-a-service models.

AEMO's investment in programs that evolve the system architecture to ensure we can be sufficiently flexible and agile to manage the complex system of the future, requires ongoing sustained increases to digital operating expenditure. AEMO is also subject to contractual inflationary increases from vendors.

Consulting

AEMO's consulting costs reflects the engagement of consulting services to support critical activities, including development of technical initiatives under the Engineering Framework to 100% Renewables, cyber security programs and other strategic initiatives identified that reduce operational risks. Key initiatives include:

- effectively managing known and emerging power system risks by continuing to uplift modelling and information, reviewing actual and potential power system events, and ensuring policies and procedures reflect our latest operational risks
- energy system design, including reviewing technical standards and requirements for connecting into the NEM

Depreciation and amortisation (D&A) and financing costs

D&A expenses reflect the amortisation of investments in capital projects once they 'go live'. AEMO's assets are predominantly digital (for market and organisational operations).

D&A costs have increased, reflecting the deployment of projects / initiatives relating to AEMO's Operations Technology Program and lifecycle upgrades to corporate systems.

AEMO finances its capital investment program through a combination of bank debt and fixed instruments such as Bonds. Higher market interest rates and increased borrowing requirements associated with key investments programs drives an increase in budgeted finance costs.

Other expenses

Other expenses primarily reflect costs associated with insurance costs, subscriptions and research data, office accommodation, employee related travel, recruitment and training expenditure.

Revenue requirement and fees

Revenue requirement

NEM Core represents the majority of AEMO's costs and, therefore, revenue requirement. In FY25 the NEM core revenue requirement increases by 5.9%, reflecting the planned 4.5% rate increase in the NEM benchmark fee coupled with forecast increased consumption in FY25.

The consumption forecast used in the FY25 budget is the Step Change scenario outlined in the 2023 NEM Electricity Statement of Opportunities (ESOO), updated to reflect the latest input assumptions including large industrial loads, electrification, electric vehicles, and rooftop photovoltaic (PV).

Fees

In accordance with the current *Electricity Market Participant Fee Structure*, effective from 1 July 2023, the NEM allocated fee for FY25 will be structured as follows:

- 55.9% allocated to wholesale participants
- 26.6% allocated to market customers, charged as a combination of $/MWh and $/NMI on a 50/50 basis.
- 17.5% allocated Transmission Network Service Providers (TNSP)

In line with the National Electricity Rules (NER), AEMO published its *NEM fees for TNSP allocation* in February 2024.

In FY25 AEMO will start consultation with stakeholders about a new fee structure for NEM Core to take effect from 1 July 2026.

Engineering our energy future

Australia's energy transition is underway and gathering pace due to a combination of aging plant, technological innovation, government policies, market forces and consumer preferences. Australians must have confidence in the reliability and resilience of energy supply through the nation's complex, interconnected and commercially focused electricity and gas systems.

Securely operating the National Electricity Market (NEM) at up to 100% instantaneous penetration of renewable energy is an unprecedented challenge. It will require a focused effort to re-engineer the system and solve technical challenges in the operation of the changing power system. AEMO’s Engineering Roadmap to 100% Renewables, published in December 2022, catalogues 174 actions that represent AEMO’s view of these engineering activities, and forms the basis of AEMO’s investment in this space.

Spearheading this engineering frontier, in FY25 AEMO will continue its engineering efforts. Key focus areas relate to addressing future power system phenomena, improving industry’s understanding of the capabilities of new technologies, integrating consumer energy resources (CER), addressing real-time operations challenges resulting from more and variable generators, and exploring transition milestone risks and resolutions.

The very nature of the work is exploratory, as AEMO grapples with new and unmet challenges that will continue to evolve over time. This work is part of AEMO’s core role to ensure system security and reliability with work being coordinated across AEMO System Design, Operations and Reform Delivery teams.

With Australia’s brightest energy system engineers passionately seeking to solve the greatest challenge of our generation, AEMO is confident it’s a challenge we can meet.

2.2. NEM Connections

Purpose

This segment covers AEMO's Onboarding and Connections activities in the NEM. Through its network connections function, AEMO is responsible for:

- assessing and negotiating performance standards to ensure power system security
- providing information on establishing or modifying connections to the transmission and distribution networks in the NEM, including;
  - generating systems
  - customer facilities
  - connections between transmission and distribution networks.
- contributing to the assessment of simulation models of power system plant and associated control systems
- commissioning and post-commissioning activities
- onboarding new connecting parties through registration process.

Participants

Connection applicants.

Fee structures that apply

This is a user pays function, with fees for service as described:

- Section 52 of the National Electricity Law (NEL)
- Registration: Refer to Table 40 Fee schedule of new NEM registrations ($ per registration)
- Connections: Generator Connection Application Fees

Segment health

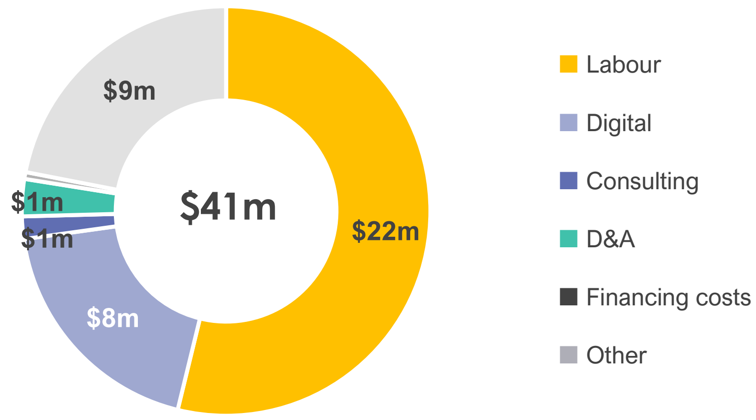
As we work with industry to navigate Australia's energy transition, AEMO is committed to ensuring our role in the connection process is responsive, efficient and predictable for market participants. In the 12 months to March 2024 AEMO received 81 new connection applications, up from 53 in the previous 12 months. AEMO expects this trend to continue and is investing in our workforce, processes and tools to meet increasing demand.

Table 2 FY25 NEM Connections Profit and Loss summary

	Budget FY24 $m	Budget FY25 $m	Variance $m	Variance %
Revenue	26.5	44.5	18.0	68.1%
Operating costs	25.8	40.8	15.0	58.1%
Annual surplus/(deficit)	0.7	3.8	3.0	N/A
Accumulated surplus/(deficit)	**1.6**	**2.1**	**0.5**	**N/A**

Segment investment

Chart 4. FY25 Budgeted operating cost profile for NEM Connections ($m)



2.3. NEM 'Functions'

Purpose

AEMO performs a number of functions (or services) that support the operation of the NEM, including:

- national transmission planning (NTP)
- management of five-minute settlements (5MS)
- trading in Settlements Residue Auction (SRA)
- management of the NEM Reform Program
- facilitation of retail market competition
- provision of a consumer data platform
- integrating Distributed Energy Resources (DER) into the NEM

Read more about what AEMO does in this segment by referring to Appendix A: Segment, function, and function purpose.

Participants

- Participants in this segment include: market customers, wholesale participants and Transmission Network Service Providers

Fee structures that apply

- Electricity Fee Structures: March 2021
- Structure of Participant Fees for AEMO's NEM2025 Reform: October 2023
- Structure of Participant Fees for the Consumer Data Right Declared NEM Project: June 2023

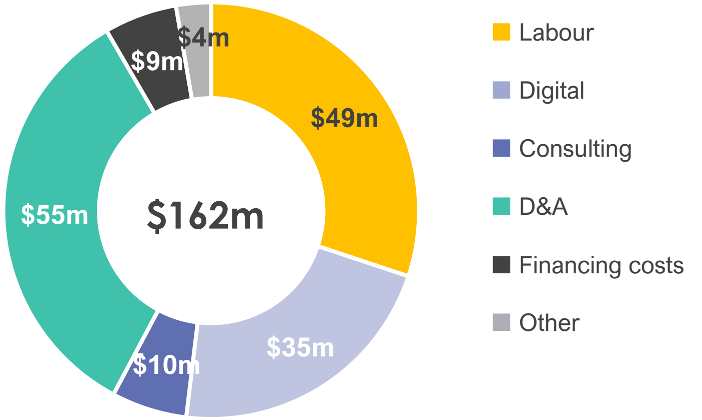
Segment health

Table 3 NEM Functions profit and loss summary FY25

	Budget FY24 $m	Budget FY25 $m	Variance $m	Variance %
Revenue	87.2	167.7	80.5	92.4%
Operating costs	103.7	162.3	58.6	56.6%
Annual surplus/(deficit)	(16.5)	5.4	21.9	N/A
Accumulated surplus/(deficit)	**(3.8)**	**(1.2)**	**2.6**	**N/A**

Segment investment

Chart 5. FY25 Budgeted operating cost profile for NEM Functions ($m)



General

In FY25, segment costs increase by $59m (57%) compared to FY24, predominantly related to the NEM Reform program ($34m) and NTP ($19m), reflecting depreciation and amortisation and associated ongoing costs of projects delivered and the inclusion of costs associated in delivering the commonwealth initiative also known “Supercharged ISP”.

The majority of costs (61%) within NEM Functions relates to amortisation of the capital spend, and IT&T costs to run 5MS / GS and planks of the NEM reform program, which went live in FY24, as well as the financing costs associated with the capital required for this program.

National Transmission Planner

The budgeted costs for the NTP function (NTP fees are billed to transmission network service providers) have increased in FY25, driven primarily by enhancements to the 2026 Integrated System Plan (ISP). The scope is increasing at the request of the Australian government and includes gauging community sentiment and monitoring progress against the inputs and outputs of the ISP.

In line with the National Electricity Rules (NER), AEMO published its NTP fees for FY25 in February 2024.

NEM Reform

In FY24 the NEM Reform Program, in line with the NEM2025 Reform Implementation Roadmap, several projects were deployed, including releases for Integrating Energy Storage (IESS), new Fast Frequency Market, new MT PASA information, load profiling changes, and the last tranche of Consumer Data Rights (CDR). Metering exemption changes were delivered during March 2024 and AEMO is on track to deliver Integrated Energy Storage Systems (IESS) in June 2024.

These projects are reflected in the budgeted operating expenses and are applied to participants according to the newly agreed NEM2025 Reform Program fee structure, that takes effect from 1 July 2024. The recovery of costs relating to CDR is covered under the Structure of participant fees for the Consumer Data Right (CDR) declared NEM project.

A significant pipeline of works is planned during FY25 including delivery of Frequency Performance Payments (FPP) and planning and executing a wide range of reforms. Further details can be found at: AEMO | NEM Reform Executive Forum

Revenue requirement and fees

Refer to Section 4.2 NEM ‘functions’ fees for the revenue requirement and associated fees for NEM Functions.

2.4. East Coast Gas

Purpose

AEMO performs a number of functions relating to the East Coast Gas markets, including:

- operating the Victorian Declared Wholesale Gas Market (DWGM)
- facilitating the Short-Term Trading Market (STTM) and day ahead auctions (DAA)
- facilitating retail market competition
- developing the Gas Statement of Opportunities (GSOO)
- operating the Gas Supply Hub (GSH) and Capacity Trading Platform (CTP)
- administering change proposals for the Operational Transportation Service (OTS) Code

Read more about what AEMO does in this segment by referring to Segment, function and function purpose.

Participants

Participants in this segment include: wholesale and retail market participants, STTM shippers and users, bulletin board facility operators, trading participants and auction participants.

Fee structures that apply

- Structure of Gas Participant Fees: December 2023
- Gas Supply Hub Exchange Fees: March 2019

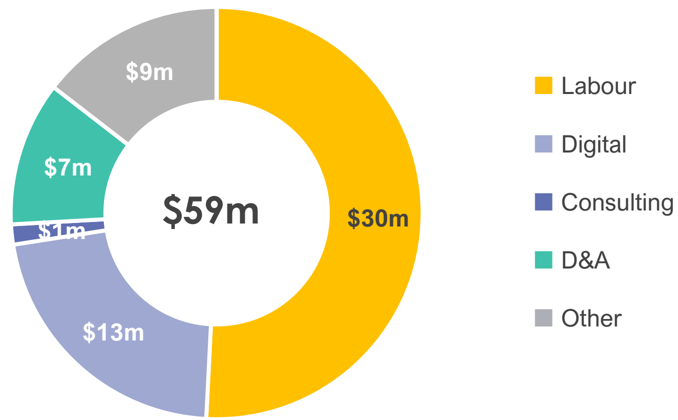
Segment health

Table 4 FY25 East Coast Gas Profit and Loss summary

	Budget FY24 $m	Budget FY25 $m	Variance $m	Variance %
Revenue	55.8	51.5	(4.2)	(7.6%)
Operating costs	57.8	59.3	1.5	2.6%
Annual surplus/(deficit)	(2.1)	(7.8)	(5.7)	N/A
Accumulated surplus/(deficit)	**58.3**	**48.8**	**(9.6)**	**N/A**

Segment investment

Chart 6. Budgeted operating cost profile for East Coast Gas FY25 ($m)



Major costs

The Victorian Declared Wholesale Gas Market functions drives the largest costs in this segment ($38m or 65%).

Gas reforms

In August 2022, Energy Ministers agreed to make a range of reforms to support a more secure, resilient and flexible east coast gas market. These actions are designed to enable AEMO to better manage gas supply adequacy and reliability risks to minimise, as far as practicable, the hazards and risks to safety of the public and customers arising from gas supply.

Stage 1 projects/initiatives that have been deployed are now reflected in the operating costs. The allocation of these costs are consistent with the new gas participant fee structure, consulted on in 2023 and effective from 1 July 2024.

AEMO will make further investment in stage 2 gas reforms that will be primarily capital investments in nature.

Other

As part of securing the Victorian Declared Transmission System against the effects of an adverse event and demand shortages, AEMO is instructed to act as both buyer and supplier of last resort in relation to the Dandenong Liquefied Natural Gas (DLNG) storage facility over 2023-2025. As a result, AEMO is required to secure all uncontracted gas (excluding operational and non-market LNG storage) and storage capacity. In FY25 the storage costs are budgeted to be $8.4m.

In addition, and in accordance with its obligations as operator of the DWGM, AEMO is undertaking activities related to gas safety management for the Victorian Declared Transmission System, including how gas is conveyed, supplied, measured and controlled. AEMO has budgeted $1m for this work in FY25.

Revenue requirement and fees

The segment revenue requirement reflects a revenue reduction of $4.2m in FY25, reflecting an increase in return of surplus compared to FY24 of $6m.

Refer to Section 4.4 East Coast Gas (ECG) fees for the revenue requirement and associated fees for ECG.

2.5. WA: WEM and GSI

Purpose

AEMO performs a range of functions for the Western Australia (WA) Wholesale Electricity Market (WEM):

- market operations: operating and settling the Reserve Capacity Mechanism and managing the buying and selling of electricity in the Short Term Energy Market, Load Following Ancillary Service Market and Balancing Market
- power system operations: Maintaining the Southwest Interconnected System (SWIS) in a secure and reliable state, working alongside the network operator (Western Power) and generation facility owners

AEMO also has several functions under the Gas Services Information (GSI) Rules relevant to WA, which include operating and maintaining the Gas Bulletin Board, administering the registration process for gas market participants and publishing the Gas Statement of Opportunities (GSOO).

AEMO operates the retail market scheme in WA, providing retail market services to gas industry participants, including procedures governing market operation.

Read more about what AEMO does in this segment by referring to Segment, function and function purpose.

Participants

Participants in this segment include: market generators, network operators

Fee structures that apply

- Wholesale Electricity Market and Gas Services Information Rules
- WA Gas Retail Market Procedures

Segment health and investment

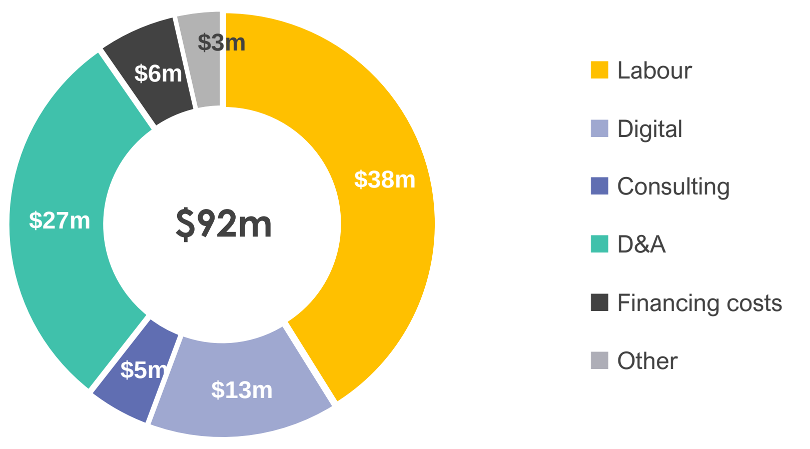
The ERA's Allowable Revenue 6 (AR6) determination, published on 31 May 2022, provided for AEMO to recover $142.3 million of costs via fees across the three years FY23 to FY25.

AEMO has worked within these allowances to deliver the WEM Reform Program and operate the power system and market in the SWIS over the first two years of the AR6 period. AEMO has proposed to the ERA that AR6 be adjusted to account for increased D&A resulting from deployed WEM reform projects, external cost pressures (inflation, labour cost escalation), allowances for critical enterprise-wide capability uplifts and adjustments for new reform and energy transition activities. The numbers below reflect AEMO's proposal, which at the time of consulting, is still under consideration by the ERA.

Table 5 FY25 WA Electricity and Gas Profit and Loss summary

	Budget FY24 $m	Budget FY25 $m	Variance $m	Variance %
Revenue	59.1	103.7	44.5	75.3%
Operating costs	66.6	92.2	25.6	38.4%
Annual surplus/(deficit)	(7.5)	11.5	19.0	N/A
Accumulated surplus/(deficit)	**(3.3)**	**1.3**	**4.6**	**N/A**

Chart 7. Budgeted operating cost profile WA WEM and GSI FY25 ($m)



2.6. Victorian Transmission Network System Planning (Vic TNSP)

Purpose

AEMO has a unique role in Victoria, where we are responsible for ensuring the Victorian transmission network is developed in an efficient way for the benefit of all Victorian electricity consumers. Our roles include planning future requirements for the declared shared network, procuring augmentations and non-network services and procuring system strength transmission services in Victoria.

AEMO is also responsible for the delivery of the VNI West project through a wholly owned subsidiary, Transmission Company of Victoria (TCV). TCV has been undertaking pre-planning and early works on this project and will tender for construction to enable the project to continue toward completion. When this occurs TCV will transfer to the successful company.

Participants

Participants in this segment include: Victorian network users, market participants and various government bodies.

Fee structures that apply

AEMO's Transmission Use of System (TUoS) charges recover the costs for providing shared prescribed transmission network services in Victoria. The TUoS revenue requirement and its allocation to each prescribed service category is determined in accordance with the National Electricity Rules (NER), AEMO's Revenue Methodology and AEMO's Pricing Methodology.

Segment health

The TUoS revenue requirement for FY25 was published in March 2024 in line with the requirement to publish TUoS prices. The budgeted revenue is $754 million, which is $104 million (16%) higher than FY24. The main drivers of the increase are external to AEMO and relate to increases in AusNet Services' Maximum Allowable Revenue (MAR), which is approved by the Australian Energy Regulator (AER), an increase in the Victorian Government easement land tax and forecast reductions in settlement residue collections in FY25, due to higher anticipated negative inter-regional settlement residue payments associated with network congestion in southern NSW.

FY25 TUoS revenue was based on a preliminary draft AEMO budget. Any over or under recovery as a result of changes between the preliminary and final budget will be recovered in FY26.

Table 6 FY25 Vic TNSP Profit and Loss summary

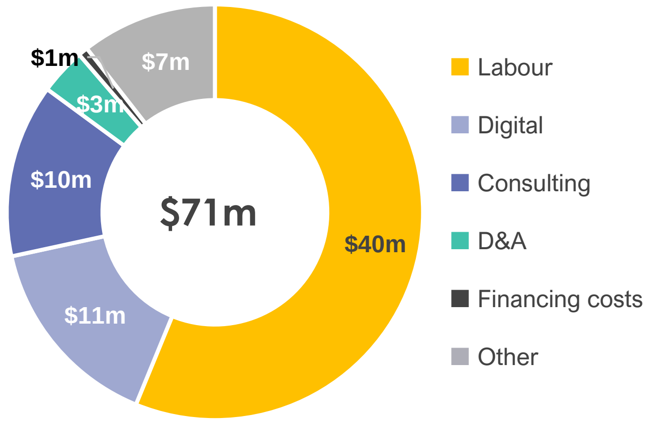
	Budget FY24 $m	Budget FY25 $m	Variance $m	Variance %
TUOS	650.2	754.2	104.0	16.0%
Other Revenue*	117.1	131.5	14.4	12.3%
Network charges	(733.8)	(797.7)	(63.9)	8.7%
Net revenue	33.5	88.0	54.5	162.3%
Operating costs	73.0	71.0	(2.0)	(2.8%)
Annual surplus/(deficit)	(39.5)	17.0	56.5	N/A
Accumulated surplus/(deficit)	**5.4**	**5.1**	**(0.3)**	**N/A**

*Other Revenue primarily include settlement residue income, revenue collection from generators for prescribed negotiated services, funding from the Victorian government relating to various projects which AEMO has been directed to undertake under orders made under the National Electricity (Victoria) Act.

AEMO's Victorian TNSP operating costs are budgeted to be slightly lower in FY25 as the VNI West project has now progressed from pre-planning to implementation stage, resulting in a higher proportion of project costs capital in nature and treated as work in progress rather than recovered through TUoS.

Segment investment

Chart 8. FY25 Budgeted operating cost profile for Vic TNSP ($m)



Future of Vic TNSP functions

AEMO is progressing discussions with the Victorian Government regarding the potential consolidation of transmission planning functions, including procurement, into one entity. VicGrid has been established by the Victorian Government to progress the Victorian Transmission Investment Framework, which is a framework for how transmission infrastructure is planned and developed in Victoria. Given the critical linkages between planning, procurement, delivery and contract management, a single entity responsible for these functions would help streamline, and improve efficiency of, the end-to-end process.

2.7. AEMO Services Limited (ASL)

Purpose

AEMO Services Limited (ASL) is a subsidiary of AEMO with an independent board and was established to provide expertise and services to support the acceleration of Australia's energy transition. In 2021, ASL was appointed as the Consumer Trustee by the New South Wales (NSW) Government, giving it a central role in NSW's energy transition.

As the NSW Consumer Trustee, ASL coordinates planning of long-term investment in generation and storage in NSW, designs and conducts competitive tenders to facilitate this investment, undertakes authorisation of Renewable Energy Zone transmission infrastructure, and provides financial risk management and advice. This work is performed under a duty to protect the long-term financial interests of NSW electricity consumers.

AEMO has been engaged to support the roll-out of the Australian Government's Capacity Investment Scheme (CIS) as an advisor and tender delivery partner, bringing together our expertise in energy market design, management and procurement. The CIS is designed to attract and accelerate investment in renewable energy infrastructure across Australia to deliver the energy transition. ASL is conducting the competitive tender process that will enable the Commonwealth to determine which projects the scheme should support, commencing with the SA-VIC Tender.

Learn more about ASL.

ASL is currently in the process of finalising its budget for FY25. The numbers included within the tables are placeholders only and subject to change.

Financial health

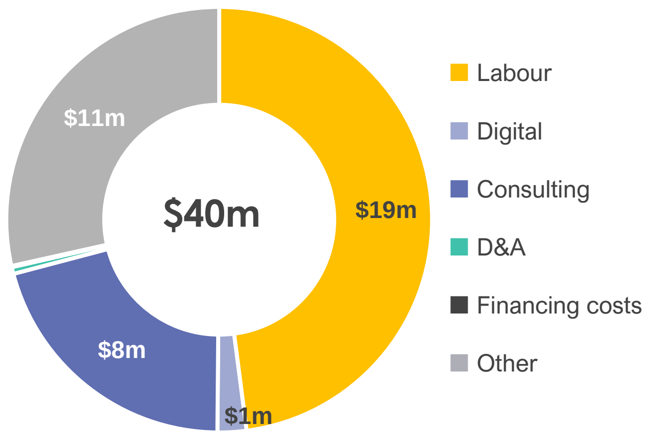
ASL operates on a not-for-profit, full-cost recovery basis. It has discrete funding arrangements to recover the cost of activities performed for each of its roles. ASL's funding arrangements and budget are not part of this public consultation are shown here for completeness, as part of the AEMO Group.

Table 7 FY25 ASL Profit and Loss summary

	Budget FY24 $m	Budget FY25 $m	Variance $m	Variance %
Revenue	36.4	39.7	3.3	9.0%
Operating costs	38.1	39.6	1.5	3.8%
Annual surplus/(deficit)	(1.7)	0.1	1.8	N/A
Accumulated surplus/(deficit)	**2.2**	**2.5**	**0.3**	**N/A**

Segment investment

Chart 9. FY25 Budgeted operating cost profile for ASL ($m)



Australia’s sustainable future depends on a cyber defensible energy system

Energy is the lifeblood of our country and way of life, delivered through Australia’s sprawling energy system to our homes, businesses, and essential services. At the heart of the energy system is AEMO, rhythmically and reliably dispatching energy to every corner of our country, adjusting as needed to stressors on the system.

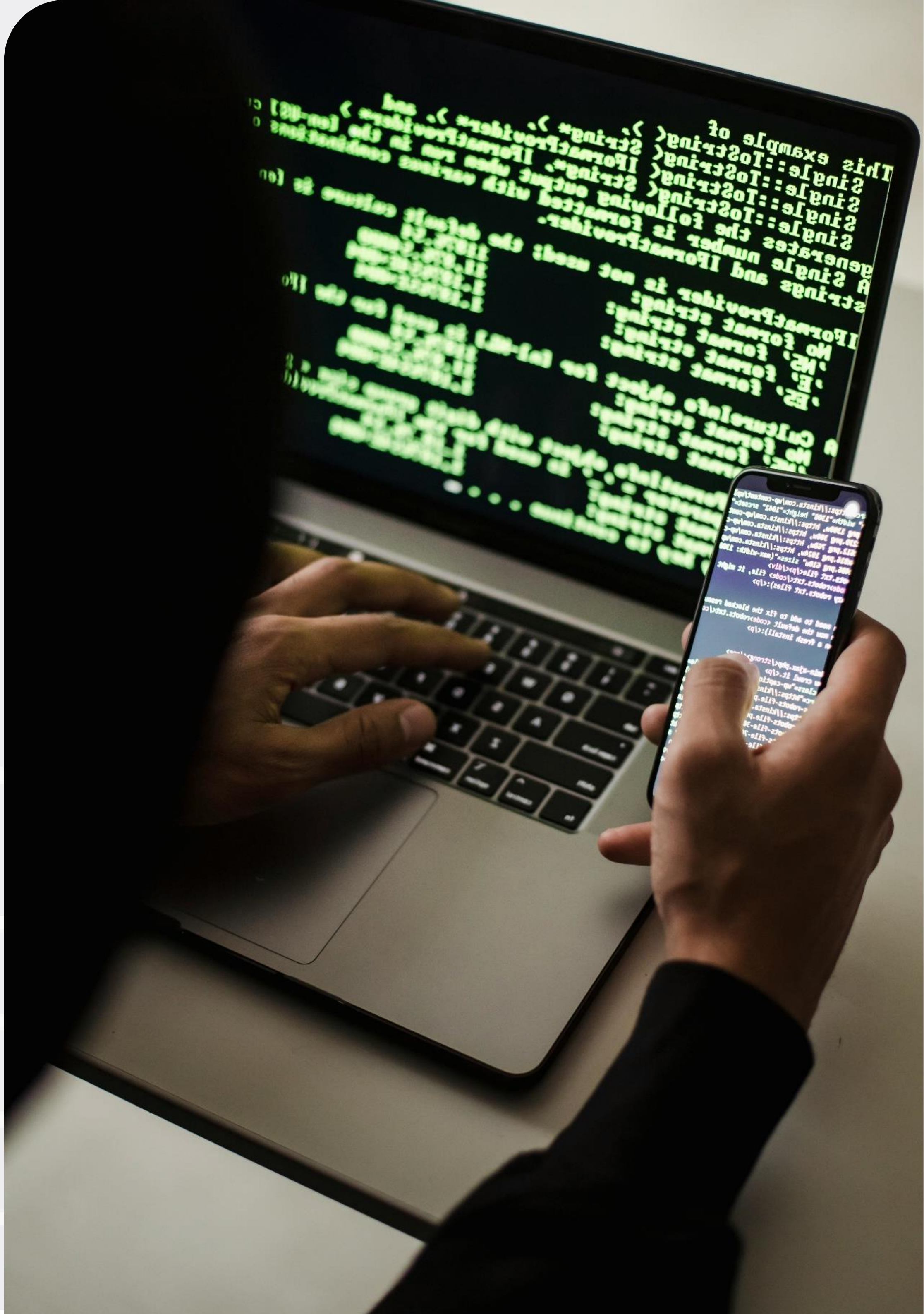
Bringing that beating heart to a stop – a real and potential outcome of nation state cyber-attacks – would have catastrophic consequences. That’s why AEMO is doing everything necessary to protect itself from malicious cyber activity.

We are doubling down on security for our existing enterprise and operating systems, seeking to close off even the smallest chink in our digital armour that could allow entry to our critical digital infrastructure. This includes employee education and training, as well as strict security and screening protocols.

We are also fulfilling the responsibilities assigned to us by Australia’s energy ministers by working with our stakeholders and industry participants, to prepare for cyber incidents, support cyber security maturity uplift, advise on sector-specific cyber security vulnerabilities and threats, and notify stakeholders of cyber threats, incidents and trends. These roles are in the process of being formalised through the Australian Energy Market Commission following a recent proposed rule change by Australia’s Minister for Climate Change and Energy.

But, as nation states wage war in new and complex ways, AEMO recognises that we are a frontline defence for Australia, and other critical infrastructure and essential services. We know that it’s not only investment in renewable technology that will enable a sustainable future, but investment in cyber defendable technologies, also. This means designing Australia’s future energy system with cyber security as a fundamental and non-negotiable outcome.

As AEMO upgrades and replaces its operating technologies to ensure they are contemporary, evergreen and can meet the demands of our changing energy system, we are also planning stronger and smarter cyber defences. This requires a step change in our capability, resources, and investment, but is a change we cannot afford not to make. More than ever, AEMO’s role is to deliver a secure energy system, but in 2024 this has new meaning than when the NEM commenced in 1998.



3. FY25 Budget summary

3.1. FY25 profit and loss summary

AEMO's FY25 budget delivers a $51m in-year surplus overall. This reflects the full remediation of the accumulated deficit in NEM Core and recovery of a forecasted deficit in the Victorian TNSP segment, partially offset by the return of surplus within the East Coast Gas segment.

Table 8 AEMO Group consolidated profit and loss summary

	Budget FY24 $m	Budget FY25 $m	Variance $m
Revenue			
Fees and tariffs	391.1	532.2	141.1
TUoS income	650.2	754.2	104.0
Settlement residue	25.6	17.9	(7.7)
Other revenue	173.9	202.5	28.6
Network charges	(733.8)	(797.7)	(63.9)
Net revenue	507.0	709.0	202.0
Operating expenditure			
Labour	262.2	308.9	46.7
Consulting	57.6	45.8	(11.8)
IT & telecommunications	76.0	120.9	44.9
Occupancy	13.0	14.1	1.1
Other expenses	46.0	45.1	(0.9)
Depreciation and amortisation	66.7	108.5	41.8
Financing costs	18.7	15.0	(3.7)
Total operating expenditure	540.2	658.2	118.0
Annual surplus / (deficit)	(33.2)	50.9	84.1
Accumulated surplus / (deficit)	**41.0**	**75.2**	**34.2**

3.2. FY25 balance sheet summary

The AEMO FY25 budget continues to stay in a positive net asset position, reflecting the recovery of NEM Core accumulated deficit and favourable financial performance against operating budget in FY23 and FY24.

Cash and cash equivalents include participant compensation funds which are held for the purposes of providing compensation for scheduling errors, and participant security deposits which protect the market from the risk of participant payment defaults. Higher pool prices resulted in an increase in participant security deposits, as observed through the first three quarters of FY24. The FY25 budget assumes the level of deposits will remain consistent to levels observed in FY24, based on assumed stable energy market prices over the year ahead.

Current liabilities include participant security deposit liabilities, which also increased for the reasons noted above for cash and cash equivalents.

Borrowings represent drawn debt from AEMO's commercial bank facilities and Medium-Term Notes (MTN). The borrowed funds are used to finance capital investment requirements and working capital requirements. An increase in budgeted borrowings for FY25 reflects higher capital expenditure requirements in FY25 to deliver greater reform, partially offset by progress on the recovery of the NEM Core accumulated deficit.

VNI West related capital expenditure and associated debt is budgeted within Transmission Company Victoria (TCV), a wholly owned subsidiary of AEMO and is included within the AEMO Group consolidated Balance Sheet summary.

Consistent with our financial principles, AEMO is committed to achieving a debt to assets ratio of under 100% and maintain a liquidity ratio above 50%.

Table 9 FY25 AEMO Group consolidated balance sheet summary

	Budget FY24 $m	Budget FY25 $m	Variance $m
Assets			
Cash and cash equivalents	137.1	330.1	193.0
Other current assets	149.8	169.1	19.3
Non-current assets	657.4	753.5	96.1
Total assets	**944.3**	**1,252.7**	**308.4**
Liabilities			
Current liabilities	313.2	465.0	151.8
Borrowings (non-current)	527.1	687.7	160.6
Other non-current liabilities	32.0	23.4	(8.6)
Total liabilities	872.3	1,176.1	303.8
Net assets	**72.0**	**76.5**	**4.5**
Equity*			
Capital contribution	7.1	7.1	0
Participant Compensation Fund reserve	10.7	11.2	0.5
Land reserve	4.1	4.1	0
Accumulated surplus/ (deficit)	50.1	54.1	4.0
Total equity*	**72.0**	**76.5**	**4.5**
Ratios			
Debt / total assets	55.8%	54.9%	(0.9%)
Current assets / Current liabilities	91.6%	107.3%	15.7%

*Total equity includes non-controlling interest share of $3.9M (FY25) relating to AEMO Services Limited. AEMO has 70% controlling interest in ASL.

3.3. Investing in Australia's energy future

As industry invests in new infrastructure, AEMO must invest in the development of supporting IT systems and business processes to enable the reform, while maintaining reliability and security. The capital investment program reflects our regulatory responsibilities and the objectives detailed in our corporate plan.

AEMO has been tasked with implementing the Energy Security Board's (ESB) Post 2025 Electricity Market Design reforms to ensure the system and the energy market are fit for the operating conditions expected in the near future.

AEMO is working closely with stakeholders to progress implementation of reforms via the *NEM 2025 Implementation Roadmap.* The roadmap establishes a basis upon which AEMO and stakeholders can collaboratively navigate the breadth of reforms, de-risks delivery by coordinating change and avoiding unnecessary or duplicative costs and informs implementation timing. It will identify where strategic investments can be made to deliver efficient outcomes for AEMO, market participants and consumers.

In the west, AEMO is deeply involved with the WA government's *Energy Transformation Strategy.* This strategy is the government's program to deliver an improved WEM and South-West Interconnected System (SWIS) design to ensure the delivery of secure, reliable, sustainable and affordable electricity to Western Australians for years to come. The WEM Reform Program will deliver a new Wholesale Electricity Market (WEM) that addresses today's security and market effectiveness challenges. The new market went live on 1 October 2023. In parallel we are enabling Distributed Energy Resources and new technologies to be an integral part of the SWIS.

Table 10 Draft AEMO's FY25 Investment Plan

Program	Budget FY24 $m	Budget FY25 $m	Variance $m	Variance %
Reform Delivery (NEM and East Coast Gas)	69.8	73.9	4.1	5.9%
WA program	36.2	32.1	(4.1)	(11.3%)
Designing and modernising Market Operations systems	27.7	53.5	25.8	93.1%
Modernising Business Systems	23.7	25.2	1.5	6.3%
AEMO Capital Expenditure	**157.4**	**184.7**	**27.3**	**17.3%**
Project related operating costs#	17.5	38.6	21.1	120.6%
Total Investment expenditure*	**174.9**	**223.3**	**48.4**	**27.7%**

Project related operating costs includes items that are software as a service (SaaS), feasibility studies and costs that are attributed to be operating in nature during the delivery of the investment program. These costs are captured as operating expenditure in the FY25 budget and fees (i.e. not additional).

* VNI West capital expenditure is budgeted within Transmission Company Victoria (TCV), a wholly owned subsidiary of AEMO, and will is funded by a separate concessional facility. FY25 Budgeted investment spend is ~$36m.

A full list of AEMO's major programs and initiatives is available on our website.

Table 11 AEMO's four key Investment Programs

Operating today's systems and markets

Program: Operations technology

Modernise operating technology systems and tools and increase systems capability to manage greater system volatility and complexity resulting from increased penetration of renewable energy sources, more connections and data, and ensure a secure, reliable, resilient, safe and flexible operation.

Key projects/releases scheduled for deployment in FY25*

- Energy Management System upgrade for the NEM
- Market clearing engine for the Victorian DWGM
- Fast electromagnetic transient contingency analysis simulator
- New operations forecasting platform and Wide Area Monitoring Systems upgrade

Cost recovery within segment

- NEM Core
- WA: WEM and GSI
- East Coast Gas

Navigating the energy future

Program: NEM Reform

NEM Reform is a large-scale, complex, industry-wide program, supporting the transition of the NEM and bringing Australia closer to a net-zero future.

The reform agenda covers:

- ESB initiatives that form the core of the program.
- Strategic and foundational initiatives that provide necessary technology to enable the ESB initiatives.
- Parallel initiatives which are regulatory reform initiatives.

Key projects/releases scheduled for deployment in FY25*

- Retail Market Improvements
- Frequency Performance Payments

Cost recovery within segment

- NEM Functions

Navigating the energy future

Program: WEM Reform

Deliver a new wholesale electricity market for the SWIS that addresses today's security and market effectiveness challenges. This includes the introduction of security constrained economic dispatch and extensive changes to the reserve capacity mechanism.

Key projects/releases estimated for deployment in FY25*

Various planks of the RCM review including:

- RCM Methods
- Capacity Certification
- Peak RC testing – STL intervals
- Flex settlements - Registration

Cost recovery within segment

- WA: WEM and GSI

Evolving the way we work

Program: Business technology

Maintain and modernise core business systems, particularly cyber defences.

Key projects/releases scheduled for deployment in FY25*

- Cyber security uplifts
- Data centre consolidation and operational data storage capability
- Lifecycle upgrades
- Finance system
- Enterprise risk management system

Cost recovery within segment

- Costs are allocated either directly or indirectly to relevant segment/s

3.4. Capital management roadmap

AEMO's capital investments and short-term working capital requirements are facilitated through debt financing. By financing large capital projects with debt, this enables capital costs to be applied over the life of the asset.

Due to extensive market reform driving increased capital investment, AEMO's debt has increased over recent years. AEMO is optimising the risk and cost of its capital structure by:

- ensuring adequate working capital and standby liquidity
- undertaking debt refinancing well in advance of maturity to provide optionality
- seeking to diversify tenor and funding sources, as observed through the recent MTN issue
- seeking concessional debt facilities for specific initiatives

3.5. FY25 cash flow summary

AEMO's FY25 budgeted cash flow is shown in Table 12. The increase in net cash flows from operating activities is primarily from receipts from customers in Vic TNSP, NEM functions and NEM core partially offset by higher payments to suppliers and employees.

The level of investment in intangible assets has increased due to the work on Reform programs and the VNI West Project.

Table 12 FY25 Consolidated Cash Flow Summary

	Budget FY24 $m	Budget FY25 $m	Variance $m
Receipts from customers	498.8	633.8	135.0
Payments to suppliers and employees	(427.2)	(453.6)	(26.4)
Net interest and finance costs paid	(6.8)	(16.2)	(23.7)
Net receipts into Participant Compensation Fund	-	-	-
Net cashflows from operating activities	**64.8**	**164.0**	**99.82**
Net receipt of participant security deposits	(5.3)	-	5.3
Net payments for intangible assets	(200.4)	(235.0)	(34.6)
Net cashflows from investing activities	**(205.7)**	**(235.0)**	**(29.3)**
Net borrowings	65.1	53.6	(11.5)
Repayments of lease liabilities	(5.4)	(8.4)	(3.0)
Net cashflows from financing activities	**59.8**	**45.2**	**(14.6)**
NET CASH FLOW INCREASE/DECREASE	**(81.1)**	**(25.8)**	**55.3**

Note: VNI West related capital expenditure and associated debt funding has been included within investing and financing lines of the above cashflow.

4. Revenue requirements and fees

The following tables present the revenue requirement and fees (excluding any applicable GST) that will apply from 1 July 2024 for each function within each energy market.

4.1. National Electricity Market (NEM) 'Core' fees

The NEM benchmark fee is set to increase by 4.5%, in line with the three-year deficit recovery fee pathway from FY23 to FY25. Forecast consumption is estimated to increase in FY25 by 1.4% which has resulted in a higher revenue requirement for the budget year.

The FY25 budget is based on the *Step Change* scenario from the 2023 *NEM Electricity Statement of Opportunities* (ESOO), updated to reflect the latest input assumptions including large industrial loads, electrification, electric vehicles, and rooftop photovoltaic (PV).

In accordance with the National Electricity Rules, AEMO has published its *NEM Core Fees for Transmission Network Service Providers* on 15 February 2024.

Table 13 NEM Core revenue requirement and fees FY25

	Budget FY24	Budget FY25	Variance $	Variance %
NEM revenue requirement $m	201.72	213.68	11.96	5.9%
Consumption (GWh)	173,560	175,934	2,374	1.4%
Connection points (Million)	10.70	10.82	0.13	1.2%
NEM FEE BY PARTICIPANT TYPE				
Market customer fee ($/MWh)	0.28255	0.29525	0.01270	4.5%
Market customer fees ($ per connection point per week)	0.08817	0.09228	0.00411	100.0%
Wholesale participants allocation $m	78.93	83.61	4.68	5.9%
TNSP allocation $m	25.11	26.18	1.07	4.3%
NEM benchmark fee# $/MWh	1.16225	1.21455	0.05230	4.5%
Participant Compensation Fund* $m	NIL	NIL	NIL	NIL

* There is no requirement for collection of participant compensation fund (PCF) in FY25. PCF fee applies to Scheduled Generators, Semi-Scheduled Generators and Scheduled Network Service Providers.
# The NEM benchmark fee is calculated by dividing the total revenue requirement by the total forecast consumption.

Table 14 NEM Core revenue requirement breakdown

FUNCTION	RATE $	RECOVERY BASIS
NEM UNALLOCATED FEES (30%)		
Market customers	0.18218	MWh of customer load
Market customers	0.05694	Per connection point per week
NEM ALLOCATED FEES (70%)		
Market customers	0.11307	MWh of customer load
Market customers	0.03534	Per connection point per week
Wholesale participants	N/A	Daily rate calculated on 2023 capacity/ energy basis
Transmission Network Service Providers	N/A	Energy consumed for the latest completed financial year

4.2. NEM 'functions' fees

Electricity retail market

The electricity retail market revenue requirement included cost recovery relating to Consumer Data Right (CDR) Reforms. The FY25 retail market revenue is 25% higher compared to FY24 reflecting associated costs to operate the function and revenue normalisation due to FY23 and FY24 revenue were set lower to return accumulated surplus.

Electricity retail market fees apply to market customer with a retail licence.

Table 15 Electricity retail market revenue requirement and fee

	Budget FY24	Budget FY25	Variance $	Variance %
Electricity retail market revenue requirement $m	16.25	20.31	4.06	25.0%
Connection points (Million)	10.70	10.82	0.13	1.2%
Electricity retail market fees ($ per connection point per week)	0.02923	0.03609	0.00686	23.5%

5MS and Global Settlements (GS) compliance (5MS/GS) and IT upgrade

The FY25 5MS/GS/GS revenue requirement is set in line with FY24 to return accumulated surplus.

Table 16 5MS/GS revenue requirement and fee

	Budget FY24	Budget FY25	Variance $	Variance %
5MS/GS revenue requirement $m	42.31	42.31	0.00	0.0%
Consumption (GWh)	173,560	175,934	2,374	1.4%
Connection points (Million)	10.70	10.82	0.13	1.2%
5MS/GS FEE BY PARTICIPANT TYPE				
Market customer fee ($/MWh)	0.09996	0.09861	(0.00135)	(1.4%)
Market customer fees ($ per connection point per week)	0.03119	0.03082	(0.00037)	(1.2%)
Wholesale participants allocation $m	7.6	7.6	NIL	NIL
5MS/GS benchmark fee# ($/MWh)	0.24379	0.24050	(0.00329)	(1.3%)

The benchmark fee is calculated by dividing the total revenue requirement by the total forecast consumption.

Distributed Energy Resources Integration Program (DER)

The FY25 DER revenue requirement is 15% higher than FY24 primarily due to revenue normalisation. DER revenue was reduced in prior years to return accumulated surplus.

Table 17 DER revenue requirement

	Budget FY24	Budget FY25	Variance $	Variance %
DER revenue requirement $m	5.14	5.91	0.77	15.0%
Consumption (GWh)	173,560	175,934	2,374	1.4%
Connection points (Million)	10.70	10.82	0.13	1.2%
DER FEE BY PARTICIPANT TYPE				
Market customer fee ($/MWh)	0.01184	0.01344	0.00160	13.5%
Market customer fees ($ per connection point per week)	0.00370	0.00420	0.00050	100.0%
Wholesale participants allocation $m	1.03	1.18	0.15	15.0%
DER benchmark fee # $/MWh)	0.02961	0.03359	0.00398	13.4%

The fee listed above as a benchmark fee is calculated by dividing the total revenue requirement by the total forecast consumption.

National Electricity Market (NEM) 2025 Reform Program

In line with the *October 2023 Structure of participant Fees for AEMO's NEM2025 Reform Program*, AEMO will start recovering cost relating to NEM2025 reform program from 1 July 2024. The FY25 revenue requirement included recovery of system establishment cost from go-live date, ongoing cost for the budget year and recovery of a portion of prior year deficit.

The NEM2025 Reform Program fee to recover costs of from Wholesale Participants (27.5%) and from Market Customers (72.5%) charging the following fee metrics:

For Wholesale Participants: 50% is charged as a daily rate based on aggregate of the higher of the greatest registered capacity and greatest notified maximum capacity (of energy or Frequency Control Ancillary Service (FCAS) markets) in the previous calendar year of units from Wholesale Participants; and 50% is charged as a daily rate based on MWh energy, or in the case of Market Ancillary Service Providers Executive summary (MASPs) / Demand Response Service Providers (DRSPs) the equivalent FCAS enablement, scheduled or metered (in previous calendar year).

For Market Customers: 37% is charged as a rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in the spot market transactions by Market Customers during that financial year. The rate is applied to the actual spot market transactions in the billing period; and 63% is charged on a per connection point basis per week.

Table 18 NEM2025 revenue requirement

	Budget FY24	Budget FY25	Variance $	Variance %
NEM2025 revenue requirement $m	N/A	63.48	N/A	N/A
Consumption (GWh)	N/A	175,934	N/A	N/A
Connection points (Million)	N/A	10.82	N/A	N/A
NEM2025 FEE BY PARTICIPANT TYPE				
Market customer fee ($/MWh)	N/A	0.09679	N/A	N/A
Market customer fees ($ per connection point per week)	N/A	0.05151	N/A	N/A

Wholesale participants allocation $m	N/A	17.46	N/A	N/A
NEM2025 benchmark fee # $/MWh)	N/A	0.36363	N/A	N/A

The fee listed above as a benchmark fee is calculated by dividing the total revenue requirement by the total forecast consumption.

National Transmission Planner (NTP)

The FY25 NTP revenue requirement was published on 15 February 2024, as per the National Electricity Rule requirement. This fee applies to Coordinating Network Service Providers.

Table 19 National Transmission Planner revenue requirement

	Budget FY24	Budget FY25	Variance $	Variance %
NTP revenue requirement $m	19.57	30.35	10.78	55.1%

Other budgeted revenue requirements

AEMO also collects revenue to recover the costs of the South Australian planning function, administration of the Settlement Residue Auctions (SRAs) and Consumer Data Platform.

The revenue requirement for South Australian planning for FY25 is set to remain consistent with FY24.

Expenses associated with administration of SRAs are recovered on a cost recovery basis. Budgets and fees are required to be set for three years in advance, with over or under recoveries recovered in subsequent years.

Consumer Data Platform revenue is estimated based on the contract agreement values.

Table 20 Other revenue requirement and fees

	Budget FY24	Budget FY25	Variance $	Variance %
SA planning	1.00	1.00	NIL	NIL
Settlement Residue Auctions	0.74	0.78	0.03	4.6%
Consumer Data Platform	0.67	0.70	0.03	4.9%

4.3. East Coast Gas (ECG) fees

Declared Wholesale Gas Market (DWGM)

The DWGM revenue requirement for FY25 is 4.2% lower compared to FY24, reflecting a return of accumulated surplus.

The DWGM tariff for FY25 is in line with FY24 reflecting lower revenue requirement driven by lower consumption forecast for the budget year. The FY25 consumption forecast is based on the *Step Change* scenario from the 2024 *Gas Statement of Opportunities* (GSOO). The GSOO forecasts reflect a significant decrease (81%) in gas powered generation and modest declines for industrial (4%) and residential and commercial consumption (1%).

Distribution meter fee

The Distribution meter fee is paid by each market participant connected to a declared distribution system, or those customers are connected to a declared distribution system, at a connection point which there is an interval metering installation.

The distribution meter fee is set to recover the cost relating to metering data services. For FY25, the meter fee is set at $1.54196 per meter per day, which is 9.2% higher compared with FY24 primarily reflecting the impact of cost inflation and a recovery of forecast deficit.

Table 21 DWGM revenue requirement and fees

	Budget FY24	Budget FY25	Variance $	Variance %
DWGM revenue requirement (Energy tariffs) ($m)	12.33	11.81	(0.52)	(4.2%)
Gas consumption (TJ)	222,686	213,302	(9,384)	(4.2%)
Distribution meters (Avg)	1,087	1,087	NIL	NIL
DWGM VARIABLE FEES				
Energy tariff ($/GJ withdrawn)	0.05535	0.05535	NIL	NIL
Distribution meter ($/day per meter)	1.41268	1.54196	0.12928	9.2%
Participant compensation fund (PCF)	NIL	NIL		

Table 22 FY25 budget DWGM energy consumption

TJ	Budget FY24	Forecast * FY24	Budget FY25
Residential and commercial	124,269	116,690	123,352
Industrial	62,049	58,786	59,449
Export	29,066	22,435	29,130
GPG	7,302	2,064	1,371
Total	222,686	199,976	213,302
% change		(10.2%)	(4.2%)

* Forecast annual FY24 consumption as at March 2024.

Short-Term Trading Market (STTM)

The STTM revenue requirement for FY25 is $0.77m (23.9%) lower compared to FY24, reflecting a return of accumulated surplus.

The STTM activity fee includes the STTM Market Operator Service (MOS) allocation fee. Excluding the STTM MOS fees, the activity fee is 20% lower compared to FY24, reflecting reduction to revenue requirement and FY25 forecast consumption. STTM MOS allocation fee for FY25 is 34% lower than FY24 due to revenue requirement normalisation and reduction in forecast reduction.

The FY25 consumption is forecast to be 4.8% lower compared to FY24 budget, lower projected consumption for all three hubs in STTM. The FY25 forecast consumption is based on the Step Change scenario from the 2024 GSOO. The GSOO forecasts a decrease (47%) in gas powered generation and a smaller decline in residential and commercial consumption (5%), which is partially offset by increased industrial consumption (8%).

Table 23 STTM revenue requirement and fees

	Budget FY24	Budget FY25	Variance $	Variance %
STTM revenue requirement $m	3.22	2.45	(0.77)	(23.9%)
Gas consumption (TJ)	144,211	137,223	(6,988)	(4.8%)
STTM VARIABLE FEES ($/GJ withdrawn)				
Activity fee	0.02686	0.02084	(0.00602)	(22.4%)
Activity fees (excluding STTM MOS)	0.02231	0.01785	(0.00446)	(20.0%)
STTM MOS allocation fee	0.00455	0.00299	(0.00156)	(34.3%)
PARTICIPANT COMPENSATION FUND (PCF)				
PCF Fee – Syd ($/GJ withdrawn per hub per ABN)	NIL	NIL	NIL	NIL
PCF Fee – Adel ($/GJ withdrawn per hub per ABN)	NIL	NIL	NIL	NIL
PCF Fee – Bris ($/GJ withdrawn per hub per ABN)	NIL	NIL	NIL	NIL

Table 24 STTM energy consumption

TJ	Budget FY24	Forecast * FY24	Budget FY25
Adelaide	19,544	18,610	19,150
Brisbane	26,387	22,294	25,105
Sydney	98,280	87,643	92,969
Total	144,211	128,547	137,223
Percentage change		(10.9%)	(4.8%)

* Forecast annual FY24 consumption as at March 2024.

East Coast Gas (ECG) Reform

In line with the *December 2023 Structure of Gas participant Fees*, AEMO will start recovering cost relating to Stage 1 of ECGS reform from 1 July 2024. The FY25 revenue requirement included recovery of 50% system establishment cost, ongoing cost for the budget year and recovery of a portion of prior year deficit.

ECGS fees are set on the same basis as GSOO, that is 30% from producers on a $/GJ produced basis (including any LNG imports in the future) and 70% from retailers on a $/supply point basis.

The gas producer production forecast is the total East Coast gas, included anticipated production in the *2024 Gas Statement of Opportunities (GSOO)*. MIRNs basic meters is a total annual average meter in Victoria, Queensland, South Australia, New South Wales and Australian Capital Territory.

Table 25 ECG Reform revenue requirement and fees

	Budget FY24	Budget FY25	Variance $	Variance %
ECGS revenue requirement $m	N/A	3.23	N/A	N/A
Gas producers' production (PJ)	N/A	1,957	N/A	N/A
MIRNs basic meters - total (millions)	N/A	4.87	N/A	N/A
GSOO FEES				
Producer fee ($ per GJ)	N/A	0.00050	N/A	N/A
Retailer fee ($ per customer supply point)	N/A	0.03865	N/A	N/A

Victorian (VIC) retail gas market

The FY25 Victorian retail gas market revenue requirement increased by 17.8% primarily due to revenue normalisation.

Table 26 VIC retail gas market revenue requirement and fees

	Budget FY24	Budget FY25	Variance $	Variance %
VIC retail gas market revenue requirement $m	1.38	1.62	0.24	17.8%
Customer supply points (Million)	2.31	2.34	0.03	1.3%
VIC retail gas market tariff ($ per customer supply point per month)	0.04803	0.05764	0.00961	20.0%

Queensland (QLD) retail gas market

The FY25 market fee is kept the same as FY24 with revenue requirement reduce by 2.4%, reflecting a return of accumulated surplus.

Table 27 QLD retail gas market revenue requirement and fees

	Budget FY24	Budget FY25	Variance $	Variance %
QLD retail gas market revenue requirement $m	1.08	1.05	(0.03)	(2.4%)
Customer supply points (million)	0.23	0.24	0.00	1.1%
QLD retail gas market fee ($ per customer supply point per month)	0.37219	0.37219	NIL	NIL

South Australia (SA) retail gas market

The FY25 market fee is kept the same as FY24 with revenue requirement reduce by 2.9%, reflecting a return of accumulated surplus.

Table 28 SA retail gas market revenue requirement and fees

	Budget FY24	Budget FY25	Variance $	Variance %
SA retail gas market revenue requirement $m	1.36	1.32	(0.04)	(2.9%)
Customer supply points (million)	0.50	0.50	0.01	1.1%
South Australia retail gas market fee ($ per customer supply point per month)	0.21910	0.21910	NIL	NIL

New South Wales (NSW) retail gas market

The FY25 market fee is kept the same as FY24 with revenue requirement reduce by 1.1%, reflecting a return of accumulated surplus.

Table 29 NSW retail gas market revenue requirement and fees

	Budget FY24	Budget FY25	Variance $	Variance %
NSW retail gas market revenue requirement $m	2.73	2.70	(0.03)	(1.1%)
Customer supply points (million)	1.77	1.79	0.02	1.3%
NSW retail gas market fee ($ per customer supply point per month)	0.12555	0.12555	NIL	NIL

Eastern and South-Eastern Gas Statement of Opportunity (GSOO)

The revenue requirement increased by 4.2% in line with associated cost increase due to indexation.

Table 30 GSOO revenue requirement and fees

	Budget FY24	Budget FY25	Variance $	Variance %
GSOO revenue requirement $m	3.00	3.13	0.13	4.2%
Gas producers' production (PJ)	2,015	1,957	(58)	(2.9%)
MIRNs basic meters - total (millions)	4.81	4.87	0.06	1.3%
GSOO FEES				
Producer fee ($ per GJ)	0.00045	0.00048	0.00003	6.7%
Retailer fee ($ per customer supply point)	0.03589	0.03746	0.00157	4.4%

Gas Supply Hub (GSH)

Fees are determined outside of AEMO's budget and fee setting process through a consultation process and are set within the *Gas Supply Hub exchange agreement*.

Table 31 GSH revenue requirement and fees

	Budget FY24	Budget FY25	Variance $	Variance %
GSH revenue requirement $m	2.05	2.05	NIL	NIL
Gas consumption (TJ)	35,100	35,100	NIL	NIL
TRADING PARTICIPANT FEES				
Fixed fee - on licence per annum	12,000	12,000	NIL	NIL
Fixed fee - additional licence per annum	12,000	12,000	NIL	NIL
Variable transaction fee - daily product fee ($/GJ)	0.03	0.03	NIL	NIL
Variable transaction fee - weekly product fee ($/GJ)	0.02	0.02	NIL	NIL
Variable transaction fee - monthly product fee ($/GJ)	0.01	0.01	NIL	NIL
OTHER PARTICIPANT FEES				
Reallocation participants - fixed fee per annum	9,000	9,000	NIL	NIL
Viewing participants - fixed fee per annum	3,600	3,600	NIL	NIL

Gas Capacity Trading Platform (CTP)

The fixed and variable fee for CTP is proposed to reduce by 36.5% in FY25 to encourage greater participation in this market.

Table 32 CTP revenue requirement and fees

	Budget FY24	Budget FY25	Variance $	Variance %
Fixed fee - on licence per annum (commodity and capacity) ($)	12,000	12,000	NIL	NIL
Fixed fee - on licence per annum (capacity only)	7,000	7,000	NIL	NIL
TRADING PARTICIPANT FEES				
Variable transportation fee ($/GJ) Daily/ Weekly/ Monthly	0.00544	0.00345	(0.00199)	(36.5%)
Variable compression fee ($/GJ) Daily/ Weekly/ Monthly	0.00544	0.00345	(0.00199)	(36.5%)

Note: the variable transaction fees for CTP includes a fee of $0.00074 relating to OTS Code Panel.

Day Ahead Auction (DAA)

Revenue requirement is lower in FY25 reflecting a return of accumulated surplus. Participant fees, including fees relating to Operational Transportation Service (OTS) Code Panel, are lower in FY25 driven by increase in total GJ gas consumption forecast.

Table 33 DAA revenue requirement and fees

	Budget FY24	Budget FY25	Variance $	Variance %
DAA revenue requirement $m	2.32	1.89	(0.43)	(18.5%)
Gas consumption (GJ) - transportation	64,000	93,750	29,750	46.5%
Gas consumption (GJ) - gas compression	16,000	31,250	15,250	95.3%
TRADING PARTICIPANT FEES				
Other transportation fee ($/GJ)	0.03139	0.01643	(0.01496)	(47.7%)
Compression fee ($/GJ)	0.02683	0.01415	(0.01268)	(47.3%)

Note: the variable transaction fees for DAA includes a fee of $0.00074 relating to OTS Code Panel.

Operational Transportation Service (OTS) Code Panel

The revenue requirement is set lower in FY25 reflecting a return of accumulated surplus in this function. The fee for FY25 is 50% lower than FY24, driven by an increase in total GJ gas consumption forecast in DAA.

Table 34 OTS Code Panel revenue requirement and fee

	Budget FY24	Budget FY25	Variance $	Variance %
OTS revenue requirement $m	0.12	0.09	(0.03)	(21.9%)
OTS Code Panel ($/GJ)	0.00147	0.00074	(0.00074)	(50.0%)

Gas Bulletin Board (GBB)

The revenue requirement increase by 5% in FY25 in line with associated costs increase due to indexation. Fees increase reflecting reduction in forecast gas production and consumption in FY25.

Table 35 GBB revenue requirement and fees

	Budget FY24	Budget FY25	Variance $	Variance %
GBB revenue requirement $m	2.45	2.57	0.12	5.0%
Gas producer production (PJ) [1]	2,015	1,957	(58)	(2.9%)
Gas consumption (TJ)	366,897	350,525	(16,372)	(4.5%)
GBB FEES				
Producer ($/GJ)	0.00061	0.00066	0.00005	7.8%
Participants in wholesale gas market ($/GJ withdrawn)	0.00334	0.00367	0.00033	9.9%

[1] 2023 GSOO, Table 5 - Forecast of available annual production as provided by gas producers, 2023-27 (PJ)

4.5. Western Australia (WA) fees

WA Wholesale Electricity Market (WEM)

The ERA's AR6 determination published on 31 May 2022, provided for AEMO to recover $142.3 million of costs via fees across the three years FY23 to FY25. The May 2022 determination, plus the subsequent September 2023 in-period capex adjustment approved by the ERA, estimated a total capex requirement of $108.6 million.

AEMO has worked within these allowances to deliver the WEM Reform Program and operate the power system and market in the South West Interconnected System (SWIS) over the first two years of the AR6 period. A number of factors were not accounted for. As a result AEMO has proposed an adjustment to AR6 Fee revenue. For more information, please refer to *AR6 second in-period submission.*

The WEM revenue requirement for FY25 is set to increase by $44.37m (79.1%) compared to FY24, consistent with the AR6 second in-period submission, subject to the ERA's final approval by 30 June 2024.

The FY25 forecast consumption is 1.4% lower than FY24. The forecast assumption is based on the *expected* scenario from the 2023 WEM Electricity Statement of Opportunities, which is currently under development.

Table 36 WEM revenue requirement and Fees

	Budget FY24	Budget FY25	Variance $	Variance %
WEM revenue requirement $m	56.08	100.46	44.37	79.1%
Energy consumption (GWh)	17,948	17,691	(259)	-1.4%
WEM FEES				
WEM fee ($/MWh) #	1.5263	2.7485	1.22214	80.1%
WEM fee (indicative benchmark) * ($/MWh)	3.0526	5.4969	2.44428	80.1%
WEM REGULATOR & COORDINATOR FEES ($/MWh)				
WA Economic Regulation Authority – Regulator fee	0.2063	TBC		
Energy Policy WA – Coordinator fee	0.0779	TBC		

WEM fee applies to Market Customers and Generators.

* Benchmark fee reflects the total of WEM fee per MWh for both Market Customers and Generators.

Western Australian Gas Services Information (GSI)

The GSI revenue requirement for FY25 is in line with FY24, reflecting associated costs to operate the function. The GSI revenue requirement is determine by the ERA and is tracking within the *Allowable Revenue – Period 6 (AR6) determination*.

Table 37 GSI revenue requirement and fees

	Budget FY24	Budget FY25	Variance $	Variance %
GSI revenue requirement ($m)	1.61	1.61	NIL	NIL
WA Economic Regulation Authority – Regulator fee ($m)	0	TBC		
Energy Policy WA – Coordinator fee $m ($m)	0.15	TBC		

Western Australia (WA) retail gas market

The WA retail gas market revenue requirement include annual member fees. For FY25, the revenue is set to increase by 12.2% reflecting cost inflation and revenue normalisation due to FY24 revenue requirement was set lower to return accumulated surplus.

The annual member fee is escalated based on a forecast and will be updated with the actual CPI following the publication of the March quarter CPI Western Australia FRC gas revenue requirement and fees.

Table 38 WA retail gas market revenue requirement and fees

	Budget FY24	Budget FY25	Variance $	Variance %
WA retail gas market gas revenue requirement $m	1.43	1.61	0.17	12.2%
Customer supply points (Million)	0.81	0.82	0.01	1.6%
WA FRC GAS FEES				
WA retail gas market fee ($ per customer supply point per month)	0.12290	0.13765	0.01475	12.0%
Annual fee – member	24,009	25,204	1,200	5.0%
Annual fee - associate member	4,682	4,915	234	5.0%

Note: associate members are self-contracting users that are partly to the WA Gas Retail Market Agreement. The FY25 annual fees are calculated according to clause 362A(5) of the Retail market Procedures (WA)

4.6. Victorian Transmission Network Service Provider (TNSP) fees

TNSP Transmission Use of Systems (TUoS) prices were published in 15 March 2024. TUoS fees are predominately influenced by network charges and easement tax billed by the Victorian electricity transmission network owners and by estimates of settlement residue receipts.

Table 39 Victorian Transmission Network Service Provider revenue requirement

	Budget FY24	Budget FY25	Variance $	Variance %
TUoS revenue requirement ($m)	650.2	753.8	103.6	15.9%

4.7. Other fees and charges

In addition to the above fees and charges prescribed under the associated rules, AEMO provides a range of services to electricity and gas markets participants which are charged on a fee-for-services (FFS) basis.

Fee schedule of new registrations

Table 40 Fee schedule of new NEM registrations ($ per registration)

The NEM registration fee has not been increased since 2018, with rises only made to match annual indexation. Over this period AEMO has seen an increase in registration scope and activities being implemented as markets expand and increase in participation. For AEMO to continue supporting at this standard, it is important to have an effective cost reflective fee structure established for Registration. Hence, as part of FY25 budget and fees process AEMO has decided to do an extensive review of all registration activities using a bottom-up approach in determining the actual effort and cost associated to each activity. AEMO is committing to be transparent to its stakeholders and preparing to separately engage with participants on the proposed fee increase.

On 3 June 2024 a new market participant category of Integrated Resource Provider (IRP) and a new classification category, the bidirectional unit, will become effective in the NEM, to enable storage and hybrids including aggregators of small units to register and participate in a single registration category rather than under two different categories. AEMO will update the registration fees in the NEM participant fee structure to reflect the IRP category during the next general consultation on the participant fee structure in 2025-2026. Until the fee structure is updated, a person applying to be registered as an IRP will be applied each current relevant registration fee to reflect the existing categories and classifications which an IRP now replaces.

For example, an application to register as an IRP in respect of a generating unit classified as a Semi Scheduled Generating Unit will charge the same registration fee as Semi Scheduled Market Generator.

An application to register as an IRP in respect of an integrated resource system will be charged the registration fees per classification.

Refer to clause 11.145.2(g) of the National Electricity Rules for when registration fees will not apply to an existing registered participant that changes their registration category.

Fees are rounded to the nearest $50.

APPLICATION TYPE	Budget FY24	Budget FY25	Variance $	Variance %
Registration as scheduled market generator [A]	26,400	41,800	15,400	58%
Registration as semi-scheduled market generator	35,600	54,850	19,250	54%

APPLICATION TYPE	Budget FY24	Budget FY25	Variance $	Variance %
Registration as non-scheduled market generator	22,950	50,750	27,800	121%
Registration as scheduled non-market generator	19,550	31,250	11,700	60%
Registration as semi-scheduled non-market generator	29,850	43,300	13,450	45%
Registration as non-scheduled non-market generator	16,100	41,950	25,850	161%
Transfer of registration	12,650	29,200	16,550	131%
Registration as market customer	12,650	13,250	600	5%
Registration as market small generation aggregator	12,650	21,728	21,750	72%
Registration as network service provider	11,500	60,800	49,300	429%
Registration as metering coordinator (MC) [B]	12,650	22,450	9,800	77%
Registration as trader	16,100	16,300	200	1%
Registration as reallocator	14,950	14,950	NIL	NIL
Registration as an intending participant	6,900	11,250	4,350	63%
Exemption from registration	6,900	10,200	3,300	48%
FREQUENCY CONTROL ANCILLARY SERVICES				
Classification of generating units as frequency control ancillary services (FCAS) generating units [B]	11,500	13,600	2,100	18%
Classification of load as frequency control ancillary services load – new ancillary services or classify load in a new region [C]	26,400	13,600	2,100	18%
Amendment of the relevant plant associated with its existing load classification, and/or aggregating further load to its existing load classification for frequency control ancillary services purposes	35,600	5,800	3,500	152%
WHOLESALE DEMAND RESPONSE				
Registration as demand response service provider	17,399	22,750	4,350	24%
Classification of load as wholesale demand response unit – new wholesale demand response unit or classify load in a new region or load forecasting area [D]	10,874	13,300	1,800	16%
Amendment of the relevant plant associated with its existing load classification, and/or aggregating further load to its existing load classification for wholesale demand response unit	2,175	2,700	400	17%
Aggregation of existing load already classified as wholesale demand response unit	2,175	2,700	400	17%
DISBURSEMENT CHARGES				
Disbursement charge – additional energy conversion model – semi scheduled market generator	5,437	6,050	300	5%
Disbursement charge – additional energy conversion model – non-scheduled market generator	2,719	3,050	150	5%
STAND ALONE POWER SYSTEM				
New participant as a market stand-alone power system resource provider (MSRP)	13,150	13,850	700	5%
Existing market participant registering as a market stand-alone power system resource provider (MSRP)	8,650	9,100	450	5%

A. Each category of Generator in this table includes applications made by persons intending to act as intermediaries.
B. This fee is additional to the fee required to register as a Generator.
C. This fee is additional to the fee required to register as a Market Customer or Market Ancillary Service Provider or Demand Response Service Provider.
D. This fee is additional to the fee required to register as a Demand Response Service Provider.

Table 42 Fee schedule of new WA WEM registrations ($ per registration)

APPLICATION TYPE	Budget FY24	Budget FY25	Variance $	Variance %
Rule participant registration application fee	2,650	2,800	150	6%
Facility registration application fee	4,900	5,150	250	5%
Facility transfer application fee	2,650	2,800	150	6%
Conditional certification of reserved capacity	1,350	1,450	100	7%
Resubmission - application for early certified reserved capacity	12,050	12,700	650	5%
Consumption deviation application reassessment application fee for non-temperature dependent loads and for relevant demand (Clause 4.26.2CC and 4.28.9B of the WEM Rules)	600	650	50	8%

Note: Rule Participant De-registration and Facility De-registration will remain at zero.

Table 43 Fee schedule of new power of choice accreditations ($ per application)

APPLICATION TYPE	Budget FY24	Budget FY25
Initial deposit – embedded network manager	2,000	2,000
Initial deposit – metering data providers	5,000	5,000
Initial deposit – metering providers	5,000	5,000
Incremental charge rate per hour	Per Table 47 AEMO charge-out rates ($ per hour)	

Table 44 Fee schedule of new gas registrations

The Gas registration fee has not been increased since 2018, with rises only made to match annual indexation. Over this period AEMO has seen an increase in registration scope and activities being implemented as markets expand and increase in participation. For AEMO to continue supporting at this standard, it is important to have an effective cost reflective fee structure established for Registration. Hence, as part of FY25 budget and fees process AEMO has decided to do an extensive review of all registration activities using a bottom-up approach in determining the actual effort and cost associated to each activity. AEMO is committing to be transparent to its stakeholders and preparing to separately engage with participants on the proposed fee increase.

Fees are rounded to the nearest $50.

MARKET	APPLICATION TYPE	Budget FY24	Budget FY25	Variance $	Variance %
Victoria Retail Gas	Market participant - retailer	21,800	33,300	11,500	53%
	Market participant - functions	21,800	19,700	-2,100	-10%
QLD Retail Gas	Retailer	19,550	33,300	13,750	70%
	Self-contracting user	19,550	32,600	13,050	67%
SA Retail Gas	Retailer	18,400	40,850	22,450	122%
	Self-contracting user	18,400	39,450	21,050	114%
NSW Retail Gas	Retailer	21,800	35,000	13,200	61%
	Self-contracting user	21,800	34,650	12,850	59%
WA Retail Gas	WA retail gas - member	14,880	15,650	770	5%
	WA retail gas - associate member	2,975	3,150	175	6%
DWGM	Market participant - retailer	22,250	23,100	850	4%
	Market participant - trader	22,250	23,100	850	4%
	Market participant - distribution centre	21,600	22,450	850	4%
STTM	STTM user (BRI, ADL, SYD hubs)	22,600	21,400	-1,200	-5%
	STTM shipper (BRI, ADL, SYD hubs)	22,600	21,400	-1,200	-5%
	STTM allocation agent	18,400	17,000	-1,400	-8%
	STTM pipeline operator	39,450	39,050	-400	-1%
	STTM distributor	39,150	38,750	-400	-1%
	STTM storage facility operator	39,450	39,050	-400	-1%
	STTM production facility operator	39,450	39,050	-400	-1%
Pipeline Capacity	Part 24 facility operator	17,250	24,800	7,550	44%
	Day ahead auction – auction participant	17,250	21,750	4,500	26%

Note: the above registration fees are per registration per registrable capacity, which is per registration.

Table 45 Registration fees to be provided on a quoted basis

MARKET	
DWGM	Market participant - producer
	Market participant - transmission customer
	Market participant - storage provider
	Participant - declared transmission system service provider
	Participant - interconnected transmission pipeline service provider
	Participant - distributor
	Participant - producer
	Participant - storage provider
	Participant - transmission customer
Retail - NSW/ACT	Network Operator
Retail - Qld	Distributor
Retail - SA	Network Operator
	Network Operator - Mildura region
	Transmission system operator
Retail - Vic	Distributor
	Transmission System Service Provider

Other fees

Table 46 Other fees

	Budget FY24	Budget FY25	Variance $	Variance %
NEMDE queue ($ per application)	16,750	17,600	850	5%
Project developer ($ per facility)	6,900	11,250	4,350	62%
Voluntary book build participant accreditation fee ($ per application)	950	1,000	50	5%
Additional participant ID ($ per additional ID)	6,150	6,500	350	5%

AEMO charge-out rates

AEMO's charge out rates are determined on the basis of cost recovery. They are calculated using the bottom-up approach, combined both direct and indirect costs.

Table 47 AEMO charge-out rates ($ per hour)

	Budget FY24	Budget FY25	Variance $	Variance %
Senior leadership	530	560	30	6%
Manager/ specialist	440	470	30	7%
Principal	350	370	20	6%
Senior	320	340	20	6%
Analyst/ engineer	300	320	20	7%
Office/ intern	250	270	20	8%

Energy Consumers Australia (ECA)

In January 2015, Energy Consumers Australia (ECA) was established by the Council of Australian Governments (COAG) Energy Council with the focus on national electricity market matters of strategic importance for energy consumers, in particular residential and small business consumers. AEMO is required to collect funding from market participants in the NEM and gas markets on ECA's behalf to fund its program of work, however, AEMO is not responsible for setting ECA's budget. In FY25, ECA has budgeted to collect $10.31m (FY24: $9.28m).

The electricity ECA fee for FY25 is $0.01343 per connection point for small customer per week, a 6.6% increase compared with FY24, reflecting increase in funding requirements (11%) and return of forecast surplus. This fee is applicable to Market Customers.

The gas ECA fee for FY25 is $0.04679 per customer supply point per month, 31.9% higher compared with FY24. The fee increase driven by increase in funding requirement (11%) and a recovery of forecast deficit in FY24. This fee applies to each retail gas market participant participating in the registrable capacity of market participant – retailer in Victoria or retailer in NSW/ACT, QLD and SA.

Table 48 ECA revenue requirement and fees

	Budget FY24	Budget FY25	Variance $	Variance %
ELECTRICITY				
Revenue requirement ($m)	6.92	7.47	0.55	7.9%
Electricity retail market - connection points for small customers	10.56	10.70	0.13	1.3%
Electricity ($/connection point for small customers per week)	0.01260	0.01343	0.00083	6.6%
GAS				
Revenue requirement ($m)	2.05	2.74	0.69	33.5%
MIRNs basic meters - total (millions)	4.81	4.87	0.06	1.3%
Gas ($/customer supply point per month)	0.03548	0.04679	0.01131	31.9%

For enquiries relating to the ECA funding requirement, please contact Director, Strategy and Corporate c/o info@energyconsumersaustralia.com.au

Appendix A. Segment, function and function purpose

Table 49 Segment, function and function purpose

Function	Summary of responsibilities[2]
NEM CORE	
NEM	AEMO is responsible for managing: • power system security and reliability • market operations and systems • wholesale metering, settlements, and prudential supervision • longer-term energy forecasting and planning services (for the eastern and southern Australian states).
NEM FUNCTIONS	
Electricity retail markets	AEMO is responsible for facilitating retail market competition in the east coast and southern states of Australia by managing and supporting: • support retail market functions and customer transfers • manage data for settlement purposes • implement market procedure changes • business to business processes.
5-minute settlements (5MS/GS)	AEMO is responsible for operating and maintaining systems and procedures necessary for financial settlement of the national electricity market at five-minute intervals.
Distributed Energy Resources (DER) program	AEMO is responsible for understanding and integrating high levels of DER into the Australian power system to ensure a smooth transition from a one-way energy supply chain – starting with large-scale generation units to consumers – to a decentralised, two-way energy system.
National Transmission Planner	AEMO is responsible for delivering an actionable Integrated System Plan (ISP).
SA Planning / South Australian Advisory Functions (SAAF)	AEMO is responsible for preparing a collection of independent reports and publishing them for the South Australian jurisdiction under Section 50B of the National Electricity Law. Under these provisions, the South Australian Government may also request AEMO to undertake additional advisory functions for the South Australian Declared Power System.
Settlements Residue SAuction Administration	AEMO is responsible for conducting Settlements Residue Auctions including: • building, updating and maintaining the auction platform • facilitate the settlement residue auction process • Manage the Settlements Residue Committee
Consumer Data Platform (CDP)	AEMO is responsible for providing a data access service to government-operated energy comparison websites.
NEM Reform program	AEMO is responsible for managing the implementation of the Energy Security Board's post-2025 electricity market design, including: • resource adequacy mechanisms • essential system services and ahead scheduling • integration of DER and flexible demand • transmission and access.

[2] For further detailed information, please see the relevant legislation and governing rules or agreement

Function	Summary of responsibilities[3]
EAST COAST GAS FUNCTIONS	
Declared Wholesale Gas Market (DWGM)	The DWGM enables competitive dynamic trading based on injections and withdrawals from the Victorian Declared Transmission System, which links producers, major users, and retailers. AEMO is responsible for: • gas system security, market operations and systems • gas system reliability and planning • wholesale metering and settlements • prudential management.
Short-Term Trading Market (STTM)	The STTM is a market-based wholesale gas balancing mechanism at defined gas hubs (Sydney, Adelaide, and Brisbane). AEMO is responsible for: • market operations and systems • Market Operator Service (MOS) – recovery of the pipeline operators' service costs in relation to the STTM and recovers this from participants • wholesale metering and settlements • prudential management.
East Coast Gas (ECG) Reform	The ECGS reforms provide AEMO with the function of monitoring, signalling and responding to risks or threats to the adequacy and reliability of gas supply in the east coast gas system. Stage 1 of the reforms was implemented for winter 2023 and these reforms will be further enhanced with longer term enduring solutions through the delivery of Stage 2. AEMO implemented the Stage 1 reforms ahead of winter 2023 and is now providing input into Stage 2, which will be progressed as a series of rule changes through the AEMC. For more information on ECGS reform, please click here
Gas retail markets	AEMO is responsible for providing the services and infrastructure to allow gas consumers to choose their retailer while also providing the business-to-business interactions to support efficient operation of the market. This includes: • supporting retail market functions and customer transfers • managing data for settlement purposes • implementing market procedure changes • operating the central IT systems that facilitate retail market services. • (Operated in Victoria, Queensland, South Australia, New South Wales, and Western Australia)
Gas Statement of Opportunities (GSOO)	AEMO is responsible for consulting, developing and reporting on annual gas consumption and maximum gas demand, and for reporting on the adequacy of central and eastern Australian gas markets to supply forecast demand over a 20-year outlook period.
Gas Supply Hub (GSH)	The GSH provides a centralised trading, settlement and clearing facility through an online portal, and enables generators, users, producers and retailers to manage their daily and future gas requirements. AEMO centrally settles transactions, manages prudential requirements, and provides reports to assist participants to manage their portfolio and gas delivery obligations.
Capacity Trading Platform (CTP)	AEMO is responsible for the maintain and operating the CTP, which facilitates the trading of pipeline capacity, including: • settlement and prudential management of capacity transactions. • exchange transaction information with facility operators to facilitate the delivery of capacity transactions. • update STTM contract rights and DWGM accreditations in accordance with transactions in integrated products.

[3] For further detailed information, please see the relevant legislation and governing rules or agreement

Day Ahead Auctions (DAA)	AEMO is responsible for facilitating DAAs, which includes: • managing and maintaining the auction platform to allocate capacity to shippers • settlement and prudential management of auction transactions • providing auction results to facility operators to facilitate the delivery of auction transactions • updating DWGM accreditations, in accordance with transactions to a DWGM interface point.
Operational Transportation Service (OTS) Code Panel	AEMO is responsible for assessing, consulting and preparing proposals to amend the Operational Transportation Service Code.
Gas Bulletin Board (GBB)	The GBB facilitates improved decision-making and trading in gas commodity and pipeline capacity, through the provision of readily accessible and up-to-date gas system and market information. AEMO is responsible for capacity outlooks, nominations and forecasts, actual flows, line pack adequacy and additional information for maintenance planning.
WA ELECTRICITY AND GAS FUNCTIONS	
Wholesale Electricity Market (WEM)	AEMO is responsible for managing: • power system security and reliability • market operations and systems • wholesale metering, settlements, and prudential supervision • preparing for and implementing the WA Government's WEM and Constrained Access Reforms • longer-term energy forecasting and planning services.
Gas Services Information (GSI)	AEMO is responsible for operating the Gas Bulletin Board (WA) and developing the WA Gas Statement of Opportunities in accordance with the Gas Services Information (GSI) Rules and relevant GSI Procedures. This includes: • providing an information website hub to provide flow information on gas, transmission, storage, emergency management with supply disruptions, and demand in WA • developing an annual planning document providing medium to long-term outlook of WA gas supply and demand and transmission and storage capacity.
Gas retail markets	Refer to gas retail markets, in East Coast Gas, above.
VICTORIAN TRANSMISSION NETWORK SYSTEM PLANNING	
Transmission Network System Planning (TNSP)	In Victoria, AEMO has declared network functions and is responsible for: • planning future requirements of the declared shared network • procuring augmentations and non-network services • playing a role in connecting new generators and loads to the system • procuring system strength transmission services in Victoria.

Appendix B. Glossary

TERM	DEFINITION
5MS AND GS	5 Minutes Settlement and Global Settlements
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AESCSF	Australian Energy Sector Cyber Security Framework
AMDQ	Authorised Maximum Daily Quantity
ASL	AEMO Services Limited
CC AUCTION	Capacity Certificate Auction
CDP	Consumer Data Platform
CTP	Capacity Trading Platform
D&A	Depreciation and Amortisation
DAA	Day Ahead Auction
DER	Distributed Energy Resource
DLNG	Dandenong liquefied natural gas
DMIRS	Department of Mines, industry Regulation and Safety (WA)
DTS	Declared Transmission System
DWGM	Declared Wholesale Gas Market
ECA	Energy Consumers Australia
ECG	East Coast Gas segment
ERA	Economic Regulation Authority
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunities
FCAS	Fast Frequency Ancillary Services
FCC	Finance Consultation Committee
FRAC	Audit and Risk Committee
FRC	Full Retail Contestability
FY23	Financial Year 1 July 2022 to 30 June 2023
FY24	Financial Year 1 July 2023 to 30 June 2024
FY25	Financial Year 1 July 2024 to 30 June 2025
GBB	Gas Bulletin Board
GJ	Gigajoule
GPG	Gas Powered Generation
GSI	Gas Services Information
GSH	Gas Supply Hub
GSOO	Gas Statement of Opportunities
GWH	Gigawatt-hour
ISP	Integrated System Plan
IT&T	Information Technology & Telecommunications
MOS	Market Operator Service
MSRP	Market Resource Provider
MWH	Megawatt-hour

NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEL	National Electricity Law
NER	National Electricity Rules
NGO	National Gas objective
NGR	National Gas Rules
NMI	National Meter Identifier
NSW	New South Wales
NTP	National Transmission Planner
OTS	Operational Transportation Service
PCF	Participant Compensation Fund
PJ	Petajoule
PV	Photovoltaic
QLD	Queensland
RIT	Regulatory Investment Test
REZ	Renewable Energy Zone
PJ	Petajoule
SA	South Australia
SRA	Settlement Residue Auction
STTM	Short Term Trading Market
SWIS	South-West Interconnected System
TCV	Transmission Company Victoria
TJ	Terajoule
TNSP	Transmission Network Service Provider
TUOS	Transmission Use of System
VIC	Victoria
VNI WEST	Victoria, New South Wales interconnector (West)
WA	Western Australia
WEM	Wholesale Electricity Market