Budget and Fees

FY24

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.

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Contents

1. Foreword

Australia is on an accelerated journey to 100% renewable energy generation. Technical innovation, ageing generation plants, economics, government policies, energy security and consumer choice are driving this transformation faster than many anticipated.

AEMO predicts that by 2025 there could be sufficient renewable energy installed to meet 100% of consumer demand for periods of time. As industry invests in new infrastructure, so too must AEMO invest in evolving our systems to ensure the system and the energy market are fit for the operating conditions expected by 2025. Investment on AEMO's part will ensure secure and reliable energy systems operations and maintain Australia's confidence in the energy transition.

While 100% renewable energy generation will usher in cleaner and more affordable energy, the path to get there is incredibly complex from an engineering, digital and market perspective. To ensure an orderly transition to a renewables future, this turbo-charged environment requires a greater degree of cooperation and collaboration across the energy sector than ever before.

The pace and extent of Australia's energy transition means more is being asked of AEMO. From re-engineering the grid and our operations room, to progressing implementation of reforms via the *NEM 2025 Implementation Roadmap*, and to increased cyber security requirements and leadership, our responsibilities and challenges continue to increase.

AEMO's budgeted program reflects our regulatory responsibilities and core work, as well as the work we need to do to meet the challenges and priorities of our reforming sector. As our work evolves, AEMO is employing more skilled and experienced people to build our capabilities and resources. This resourcing is supported by independent benchmarking, which compared AEMO's operations against energy system operators globally and found that AEMO needed to invest in support functions to ably navigate our core work and endorsed reform implementation.

As a digitally enabled business, investment in our technologies and processes is essential and ongoing to ensure we perform our functions safely, reliably, securely and efficiently now and in the future.

While we invest to prepare for the future, we are mindful that we must deliver the reforms effectively and efficiently, seek to take costs out of the industry for participants and enable consumers to experience the benefits of a renewable energy market as soon as possible. We want to provide transparency over our planning and expenditure so that our stakeholders can be confident we are delivering core services and priorities, efficiently and with prudency, and that we are applying sound financial governance and principles to our programs and operations.

In 2023 I am aware that AEMO is still building stakeholder confidence following an accumulated deficit position, from which we continue to recover. I wish to reassure stakeholders that AEMO's financial governance and health is a priority and that the executive and the Board are taking action to ensure that AEMO has the financial stability to effectively respond to and manage strategic and operational risks and deliver energy industry reform.

As Australia experiences radical and transformative levels of growth in renewable energy generation, we seek to work openly and collaboratively with our stakeholders to achieve Australia's vision, together.

Daniel Westerman
AEMO Chief Executive

2. AEMO's strategic priorities

The AEMO Board and executive have identified four high-priority areas for AEMO to enable us to deliver our core obligations, responsibilities and major workstreams, while simultaneously preparing for the energy systems and markets of the future. The priorities are described in our FY23 Corporate Plan, and will continue into the FY24 Corporate Plan, which will be published in July 2023. This budget and investment program reflect these priorities. Our priorities are:

Priority 1

OPERATING TODAY'S SYSTEMS AND MARKETS

Delivering electricity, gas and other functions and statutory responsibilities that are fundamental to AEMO's role.

AEMO is committed to maintaining secure and reliable operation of energy systems and markets while maximising benefits in the interest of consumers.

Priority 2

NAVIGATING THE ENERGY FUTURE

Collaborating with our members and stakeholders to identify emerging issues, provide technical and economic expertise and support new and ongoing reforms.

AEMO works to meet the physical and commercial challenges associated with the energy transition by collaborating with regulatory bodies, participants and consumers to develop and deliver the least-cost and lowest-risk outcomes for consumers.

Priority 3

ENGAGING OUR STAKEHOLDERS

Being transparent, collaborative and stakeholder focused. AEMO is committed to engaging with stakeholders for improved decision-making and outcomes.

We continue to strengthen our external engagement across all functions to enhance the stakeholder experience, deliver better value to our members – ultimately to support better outcomes for energy consumers.

Priority 4

EVOLVING THE WAY WE WORK

Being a transparent, efficient, stakeholder and customer-focused business with clear accountabilities, and a sustainable financial footing for the future.

This includes ongoing organisational efficiency, talent capability work, renewing our technology architecture, and embedding a consumer and stakeholder mindset in our culture and governance.

3. Budget overview

AEMO's budget reflects the costs associated with the functions and services it provides for each of the segments in which it operates, and the revenue requirements (realised through fees and charges) to fund this work. To learn more about the work AEMO does in the market segments, refer to 0 Segment, function and function purpose. The budget also includes the operating expenditure for AEMO's subsidiary AEMO Services Limited.

Having a strong and stable system and market operator – now and in the future – is an essential investment in Australia's energy future. AEMO's operational and capital investment program reflects this dual focus.

AEMO's FY24 budget reflects our committed program to deliver on our core functions and responsibilities and our strategic priorities, outlined in the corporate plan. It also reflects the growing complexity of our work and the new regulatory responsibilities AEMO is being asked to perform. Only reform implementation programs that are underway are captured in the budget. Consistent with our financial principles, energy reform programs that do not have a funding pathway are excluded.

The budget reflects remediation of the accumulated deficit for NEM Core, which will put the organisation on a sustainable financial footing for the future. The remediation comes after significant stakeholder consultation in 2022 which led to an increase in NEM Core fees to recover the accumulated deficit. Deficit recovery by FY25 is on track.

Figure 1 AEMO's financial principles

- Efficient and cost-effective delivery
- Balanced and sustainable cost recovery
- Clear, ringfenced participant and member funds
- Funding pathways for new investment
- Low tolerance for funding risk on contracted activities
- Debt-to-assets ratio <100%
- Liquidity ratio >50%
- Timely provision of AEMO budgets to market participants

Budget development and review

AEMO's Strategic Finance team develops the budget, through consultation with all business areas. Efficiency and cost-effective delivery is the first consideration in the budgeting process, as AEMO ensures we carefully invest the funds market participants provide through fees and charges. The preliminary iteration of the budget is shared with AEMO's Financial Consultation Committee (FCC), who consider and provide feedback as AEMO develops its budget, fees and corporate plan priorities.

Stakeholders are also invited to consider the draft budget as part of a broader consultation exercise prior to its finalisation.

Iterations of the budget and fees are reviewed by AEMO's Finance, Audit and Risk Committee (FRAC), including consideration of stakeholders' views obtained through the consultation process. Final review and approval is by AEMO's Board.

Separate budget and fee processes

The following have been set through other budget and review processes:

- the revenue requirement and fees for Victoria's Transmission Use of System (TUoS), which were published on 15 March 2023 and have been determined in accordance with Chapter 6A of the National Electricity Rules and AEMO's Pricing Methodology for Prescribed Shared Transmission Services
- the revenue requirement for West Australia's Wholesale Electricity Market (WEM) and Gas Services Information (GSI) functions (which are determined by the Economic Regulation Authority)
- AEMO Services Limited's (ASL's) independent board approves its funding arrangements and budget. ASL is a subsidiary of AEMO which carries out functions as appointed by National Electricity Market jurisdictions. ASL operates on a not-for-profit, full-cost recovery basis. It has specific funding arrangements to recover the cost of activities performed for NEM jurisdictions.
- the revenue requirement for National Transmission Planner (NTP) function was determined and published on 15 February 2023, in line with section 2.11.3 of the National Electricity Rules.
- AEMO has calculated its participant fees (also refer to NEM fees for Transmission Network Service Provider (TNSP) allocation) to be recovered from each specified TNSP then notified them of their charges on 15 February 2023, 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*.

As industry evolves, so too is AEMO

Since 1998, AEMO has operated a sustainable energy system that facilitated safe, reliable and affordable energy to Australian consumers. Our value lay in our ability to predictably and consistently operate the system of a relatively constant energy industry. Now, as the industry undergoes a seismic shift in consumer expectations, policy, generation and transmission, AEMO increasingly needs to be agile, adaptable and collaborative to be effective.

AEMO is investing in itself to respond to this dynamic environment and is rapidly evolving to meet our new responsibilities. We are upgrading our operations technologies to ensure they're contemporary, flexible and can deliver safe and reliable energy now and in the future; we are planning and designing the energy system of the future; and we are transforming our own operations to ensure we have the right people, processes and technology to deliver on our responsibilities.

As we evolve and grow, we are committed to doing so in a way that earns and maintains the trust of stakeholders and consumers. This includes a focus on the efficient and economical use of resources, managing risk, delivering sustainable outcomes in a timely way, and responding to stakeholder expectations.

With more than 100 projects in flight, we are ensuring projects are prioritised and sequenced in a way to ensure the right things are done at the right time and enhancing our governance, disciplines and accountability mechanisms. Our Enterprise Program Office (EPO) supports this work by providing oversight and transparency over the health and status of our portfolio; ensuring investment is prioritised and aligned to AEMO's strategic priorities; and driving data-informed decision-making across the portfolio of work.

The EPO owns enterprise Quality Assurance (QA), which plays a key role in strengthening investment governance and project delivery consistency across AEMO's portfolio. An enterprise QA review includes assessing projects against key health indicators; and identifying, tracking and communicating key risks and themes. An enterprise lessons learned register ensures transparency and executive ownership of each identified action. Regular executive reporting triggers additional actions as required to support learnings being actioned in agreed timeframes. The enterprise QA can be initiated by an executive, a project steering committee request or the EPO. The review is led by the Enterprise Capability QA lead, either using an external vendor or working closely with the EPO team.

While progressing change on multiple fronts, we are also improving our coordination and planning so that we can optimise how we sequence and bundle reforms and solutions to reduce overall cost and impacts on industry. At all times we are guided by our desire to work collaboratively with stakeholders and consumers.

Caption: Australia's energy mix is rapidly changing.

4. Budget by market segment

AEMO's budget is structured around market segments. Revenue collected through fees and charges for services provided by each segment is ringfenced and allocated directly to the segment to offset the costs incurred. The market segments are:

National Electricity Market (NEM):
- **NEM Core**
- **NEM Functions**

East Coast Gas (ECG)

Western Australia electricity and gas

Victorian Transmission Network Service Provider (VIC TNSP)

AEMO Services Limited

Chart 1. Operating expenditure by segment FY24, $M

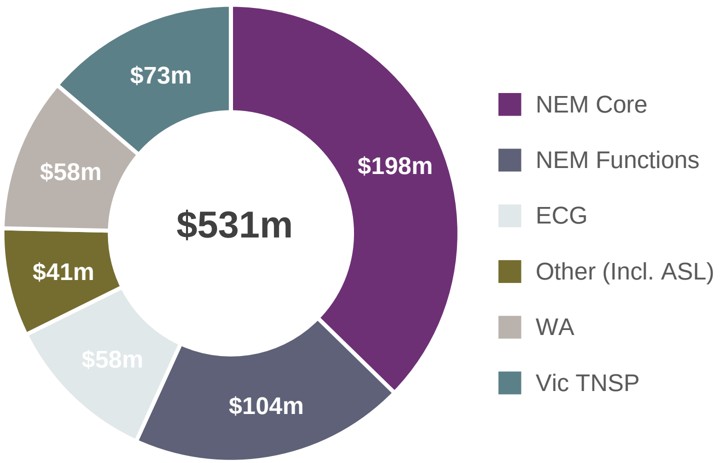
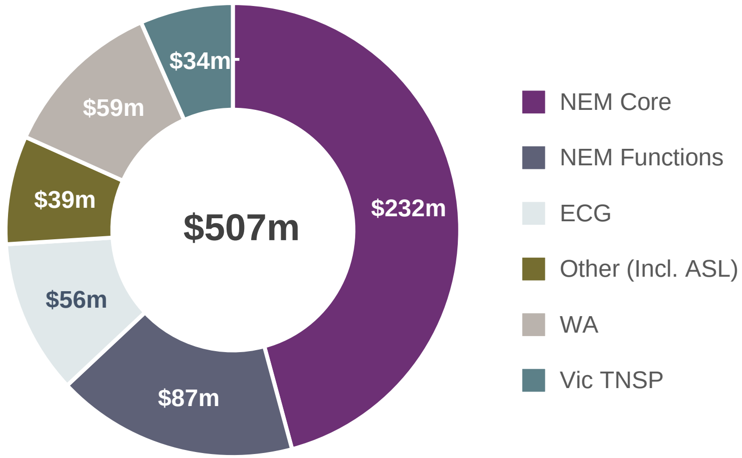


Chart 2. Revenue requirement by segment FY24, $M



'Other' primarily represents cost and revenue for services provided by ASL.

4.1. National Electricity Market (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 Appendix A: Segment, function and function purpose.

Participants

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

Segment health

Table 1 NEM Core profit and loss summary

	BUDGET FY23 ($M)	BUDGET FY24 ($M)	VARIANCE ($M)	VARIANCE (%)
Revenue	222.4	232.2	9.8	4.4%
Operating costs	188.6	198.1	9.5	5.0%
Annual surplus/(deficit)	33.8	34.1	0.3	N/A
Accumulated surplus/(deficit)	**(70.1)**	**(25.7)**	**44.4**	**N/A**

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.

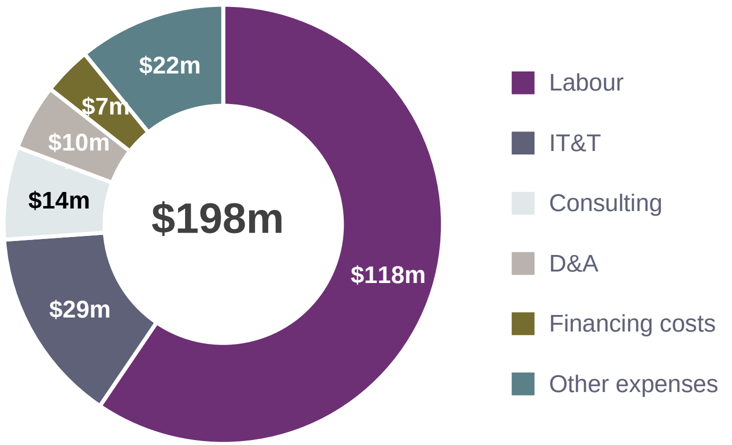
In FY23 recovery of the accumulated deficit is ahead of schedule, due to lower operating costs primarily resulting from slower recruitment in a tight labour market. We anticipate the 4.5% increase to NEM Core fees in FY24 and FY25 will achieve the stated objective of full recovery of the accumulated deficit and ensure we have sufficient revenue to continue to provide essential, core services to the NEM.

Segment investment

AEMO is being asked to take on more roles, as we contend with the renewable energy transition and the complexities it creates for reliable energy supply. The environment in which we are operating the energy markets is also fluid and ever-evolving, as we strive to take on new functions, respond to consumer sentiment and governments' priorities and seek to stay abreast of cyber threats.

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 FY24, $M



Labour

To meet the challenges of the energy transition AEMO is employing more skilled and experienced people to build our capabilities and capacity to resource our highly complex programs of work. This resourcing is supported by independent benchmarking, which compared AEMO's operations against other system operators globally and found that AEMO's investment in support functions needed to increase if it was to ably navigate our core work and energy reform.

Recruitment is occurring across the business to deliver the energy transition. Wage inflation (reflecting a tight labour market) is also a challenge.

Information Technology & Telecommunications (IT&T)

AEMO's digital operations need to evolve to manage the system volatility and exponential growth in energy resources and observable data points (as a result of new generators, batteries and connection points). As such, AEMO is investing in its system architecture to ensure we can be sufficiently flexible and agile to manage the complex system of the future and maintain electricity system reliability, security and resilience. Increased digitisation will improve AEMO's connections with the many subsystems and participants in a modern power system and improve demand management and grid flexibility.

Our corporate systems, such as enterprise resource planning and project management, also need investment to improve the effectiveness and efficiency of our work. An increasing portion of technology costs are operating expenditure in nature rather than capital expenditure, as we move to software-as-a-service models.

While costly, protecting Australia's energy sector from cyber threats is of national importance, as recognised by the inclusion of the Energy Sector in the *Security of Critical Infrastructure Act 2018* (SoCI Act). As a responsible entity under the Act, AEMO has a special role to protect market operations and continued investment is essential to protect the Australian energy market and to support participants to also continue to enhance their cyber posture.

Consulting

The budget accounts for the engagement of consulting services to support critical activities, including development of technical initiatives under the *Engineering Framework* to 100% renewables, the cyber security program and redesign of our operating models.

Depreciation and Amortisation (D&A)

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).

Financing costs

AEMO finances its capital investment program with bank debt. Higher market interest rates and increased borrowing requirements associated with additional reform program investments drives an increase in budgeted finance costs.

Other expenses

Other expenses primarily reflect costs associated with connections activities, 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 FY24 the NEM core revenue requirement increases by 3.0%, reflecting the planned 4.5% increase in the NEM benchmark fee, partly offset by reduction to forecast consumption in FY24.

The consumption forecast used in the FY24 budget is the *Step Change* scenario outlined in the 2022 *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 to the current *Electricity Market Participant Fee Structure*, effective from 1 July 2023, the NEM allocated fee will be structured as follows:

- 55.9% allocated to wholesale participants (FY23: 46%)
- 26.6% allocated to market customers (FY23: 54%), charged as a combination of $/MWh and $/NMI on a 50/50 basis (FY23: $/MWh).
- 17.5% allocated Transmission Network Service Providers (TNSP) (FY23: 0%).

In line with the National Electricity Rules (NER), AEMO published its *NEM fees for TNSP allocation* in February 2023.

Refer to 5.1 National Electricity Market (NEM) 'Core' fees and to *NEM fee structures* for more detail.

Sustainable, secure energy requires investment

Australians take it for granted that electricity will always be available: that our lights will turn on, the internet will work and that we'll be able to make our morning coffee. In fact, daily, across the energy sector, consumers may be surprised to know that thousands of cyber attacks occur, seeking to disrupt and disable Australia's energy supply. The consequence of these attacks in Australia may not only impact energy organisations, but have broader impacts to society, public health and safety, and our nation's economy. It is among Australia's most significant energy industry and national security risks.

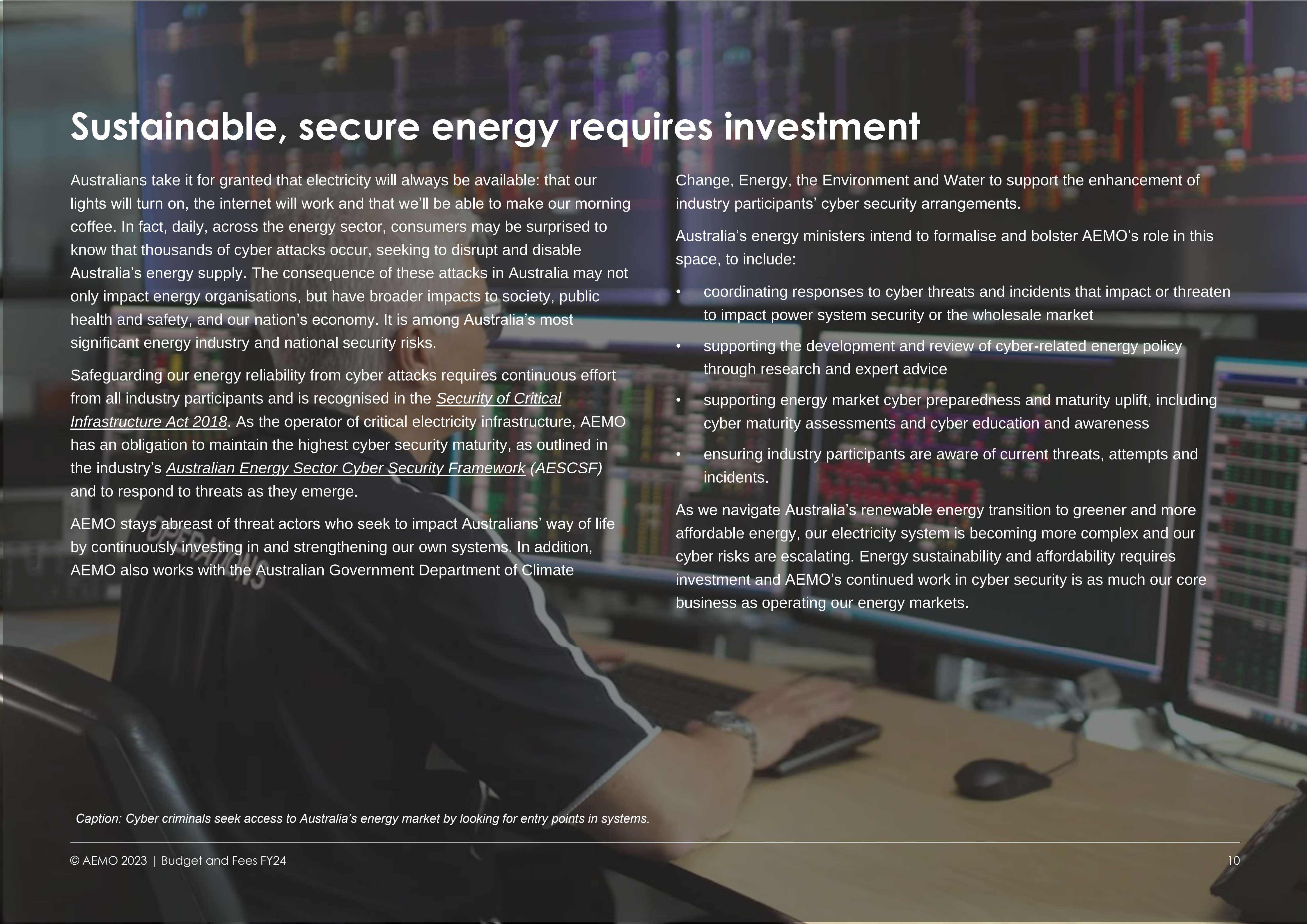
Safeguarding our energy reliability from cyber attacks requires continuous effort from all industry participants and is recognised in the *Security of Critical Infrastructure Act 2018*. As the operator of critical electricity infrastructure, AEMO has an obligation to maintain the highest cyber security maturity, as outlined in the industry's *Australian Energy Sector Cyber Security Framework (AESCSF)* and to respond to threats as they emerge.

AEMO stays abreast of threat actors who seek to impact Australians' way of life by continuously investing in and strengthening our own systems. In addition, AEMO also works with the Australian Government Department of Climate Change, Energy, the Environment and Water to support the enhancement of industry participants' cyber security arrangements.

Australia's energy ministers intend to formalise and bolster AEMO's role in this space, to include:

- coordinating responses to cyber threats and incidents that impact or threaten to impact power system security or the wholesale market
- supporting the development and review of cyber-related energy policy through research and expert advice
- supporting energy market cyber preparedness and maturity uplift, including cyber maturity assessments and cyber education and awareness
- ensuring industry participants are aware of current threats, attempts and incidents.

As we navigate Australia's renewable energy transition to greener and more affordable energy, our electricity system is becoming more complex and our cyber risks are escalating. Energy sustainability and affordability requires investment and AEMO's continued work in cyber security is as much our core business as operating our energy markets.



Caption: Cyber criminals seek access to Australia's energy market by looking for entry points in systems.

4.2. NEM ‘functions’

Purpose

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

- national transmission planning (NTP)
- management of five-minute settlements (5MS)
- trading in the Settlements Residue Auction (SRA)
- management of the NEM2025 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.

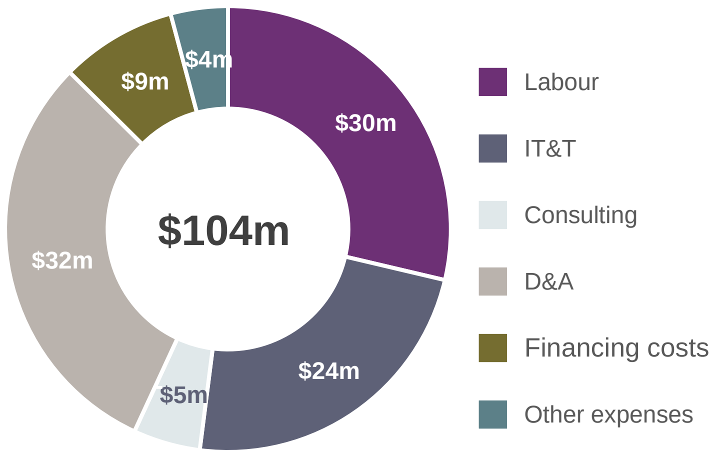
Segment health

Table 2 NEM Functions profit and loss summary

	BUDGET FY23 ($M)	BUDGET FY24 ($M)	VARIANCE ($M)	VARIANCE (%)
Revenue	92.8	87.2	(5.6)	(6.1%)
Operating costs	94.3	103.6	9.3	9.9%
Annual surplus/(deficit)	(1.5)	(16.4)	(14.9)	N/A
Accumulated surplus/(deficit)	**1.6**	**(3.6)**	**(5.2)**	**N/A**

Segment investment

Chart 4. Budgeted operating cost profile for NEM Functions FY24, $M



General

In FY24, segment costs increase by $9.3m (9.9%) compared to FY23, predominantly related to the NEM2025 program ($6.0m) and 5MS/GS ($3.6m), reflecting increased IT&T costs, financing costs, depreciation and amortisation.

The majority of costs (45%) within NEM functions relates to amortisation of the capital spend and IT&T costs to run 5MS/GS, which went live in October 2021, as well as the financing costs associated with the capital required for this program.

National transmission planner

National transmission planner accounts for 21% of the costs of the segment and includes additional investment relating to continued evolution and expansion of the Integrated System Plan (ISP). The 2024 ISP is currently being developed and is expected to deliver on further facets of the energy transition.

NEM reform

The segment also contains costs relating to the NEM2025 Reform Program – the most comprehensive reform package to be implemented since the NEM's inception in 1998. The NEM2025 Reform Program will transition the NEM into a modern energy system fit to meet consumers' evolving wants and needs. Elements of this program are scheduled to go live in FY24, including Fast Frequency Response, Ancillary Services and Integrating Energy Storage Systems. Review the full *NEM2025 Reform Implementation Roadmap*.

The segment budget captures the forecast operating costs for the NEM2025 Reform Program but has no corresponding forecast revenue for FY24. AEMO is consulting with industry participants on a fee structure for the NEM2025, which is expected to be finalised in late 2023, subsequent to which costs incurred will be recovered. To stay informed, visit AEMO's website.

Consumer Data Right (CDR)

The CDR is an important Commonwealth reform implemented via Part IVD of the *Competition and Consumer Act 2010* that will empower consumers to have greater control over their data and is seen as a key reform in moving to a digital economy. Through the reform, consumers and small businesses will be given the right to share their data between providers by using automated data technology. In February 2023, AEMO started its first round of consultation on a Participant fee structure for CDR declared NEM project, with the final determination expected to be released by late June 2023. In line with AEMO's final *Structure of participant fees for the Consumer Data Right (CDR) declared NEM project*, AEMO has updated its final Electricity Retail Markets fee to include cost recovery relating to the CDR reforms starting from 1 July 2023.

Revenue requirement and fees

Refer to 5.2 NEM 'functions' fees for the revenue requirement and associated fees for NEM Functions.

Energy markets investment yields first step in market modernisation

AEMO has reached a significant milestone in its NEM2025 Reform Program, designed to deliver the Energy Security Board's (ESB) Post 2025 Electricity Market Design and other energy market reforms.

Aggregators of small generating units (< 5 megawatts) can now register to provide Frequency Control Ancillary Services (FCAS). The introduction of these services will help keep the future power system secure and foster innovation in faster responding technologies that will help lower costs for consumers. The new market ancillary services will allow for fast frequency response to be procured by AEMO to help control power system frequency following sudden and unplanned generation or power system outages. The types of resources that are most likely to provide such services are those inverter-based technologies, such as wind, solar PV, batteries and demand-side resources.

The change modernises the Australian electricity market and will give participants access to additional value streams and promoting competition in the contingency ancillary services markets.

The initiative is the first to be delivered on the *NEM Reform Implementation Roadmap* which was released in collaboration with the NEM Reform Delivery Committee in Q3 2022. In March 2023 AEMO also released enhancements that enable important registration processes for other NEM2025 Reform Program initiatives.

Caption: The Neoen-Tesla Hornsdale Power Reserve battery storage project in South Australia.

4.3. East Coast Gas (ECG)

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 Appendix A: 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.

Segment health

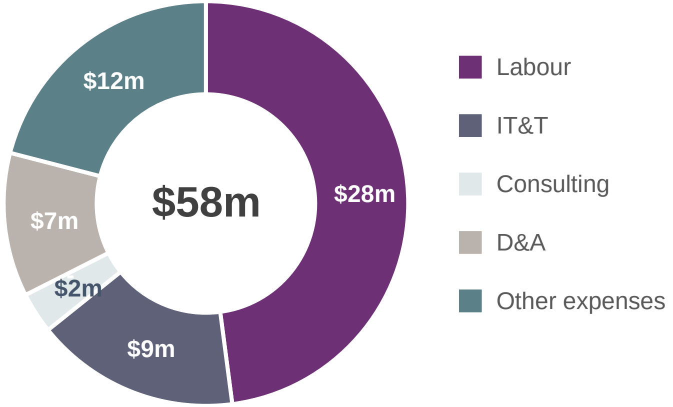
Table 3 East Coast Gas profit and loss summary

	BUDGET FY23 ($M)	BUDGET FY24 ($M)	VARIANCE ($M)	VARIANCE (%)
Revenue	47.6	55.8	8.2	17.2%
Operating costs	52.5	57.8	5.3	10.1%
Annual surplus/(deficit)	(4.9)	(2.0)	2.9	N/A
Accumulated surplus/(deficit)*	**31.3**	**67.2**	**35.9**	**N/A**

*Accumulated surplus/deficit includes a capital contribution of $8.7m relating to establishment of the DWGM market system at the formation of VENCorp.

Segment investment

Chart 5. Budgeted operating cost profile for East Coast Gas FY24, $M



Major costs

The functions drawing the largest costs in this segment ($36m or 62%) are AEMO's work on the DWGM, followed by the STTM ($6.3m or 11%).

East Coast 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 of the changes are being delivered in FY23 and in FY24 AEMO will progress stage 2 of the changes. The extension of AEMO's regulatory functions and powers to manage east coast gas supply adequacy is reflected in our labour budget. In FY24 the costs are budgeted to be ~$1.7m.

AEMO will consult on a separate fee mechanism for the ongoing recovery of these costs to come into effect from 1 July 2024.

LNG capacity and storage

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. This means AEMO is required to secure all uncontracted gas (excluding operational and non-market LNG storage) and storage capacity. In FY24 the storage costs are budgeted to be $10.8m allocated to the other cost category.

Revenue requirement

The segment revenue requirement reflects a forecast increase by $8.2m in FY24 due to:

- The Australian Energy Market Commission (AEMC) rule change, which requires AEMO to allocate capacity certificates primarily via the DGWM capacity certificates auction, thereby providing a new revenue stream for AEMO. This is forecast at $8.8m in FY24.
- A new revenue stream of $10.8m relates to recovery of the DLNG storage and liquefaction costs (previously this was recovered through part of AEMO's market fee), offset by a reduction to the DWGM tariff revenue of $14.7m.
- Interest income of $3m is budgeted in FY24 reflecting cash available as accumulated surplus in DWGM and STTM.
- Revenue is forecast to be $1m higher for day ahead auctions function due to increase in the forecast volumes.

Refer to 5.3 East Coast Gas (ECG) fees for the revenue requirement and associated fees for ECG.

4.4. WA Electricity and Gas

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 Appendix A: Segment, function and function purpose.

Participants

Participants in this segment include: market generators, network operators, and market customers.

Segment health

Following extensive public consultation, the revenue requirement for AEMO's West Australian Wholesale Electricity Market (WEM) and Gas Services Information functions for FY23 to FY25 have been determined by the Economic Regulation Authority (ERA).

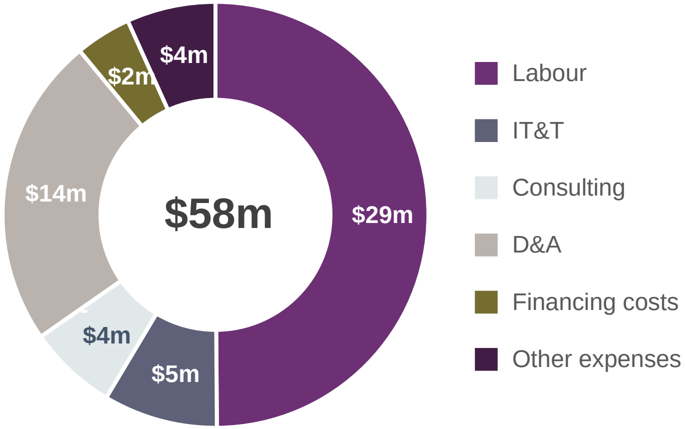
Table 4 WA electricity and gas functions profit and loss summary*

	BUDGET FY23 ($M)	BUDGET FY24 ($M)	VARIANCE ($M)	VARIANCE (%)
Revenue	44.9	59.1	14.2	31.6%
Operating costs	46.2	57.9	11.7	25.2%
Annual surplus/(deficit)	(1.3)	1.3	2.5	N/A
Accumulated surplus/(deficit)	**(0.7)**	**5.5**	**6.1**	**N/A**

*AEMO anticipates making an in-period submission to the Economic Regulation Authority (ERA) in relation to WEM reform, which could impact the FY24 budget for this segment.

Segment investment

Chart 6. Budgeted operating cost profile for WA FY24, $M



WEM reform

As part of the Energy Transformation Strategy, extensive changes are being made to the WEM, many of which are planned to commence in October 2023. AEMO is implementing these changes through the WEM Reform Program. An updated WEM Design Summary has been prepared to provide a high-level understanding of the new design.

The WEM Reform program consists of 26 work packages grouped into 11 implementation projects across six workstreams. It includes market/regulatory design and technical/process design, reserve capacity mechanism reform, constraint management, generator performance standards, integration of DERs, and power systems operations. The reform program drives the majority of increase in expenditure in the WA segment in FY24. Key areas of increased expenditure are:

- increased labour required to manage the transition to new market design
- development, and deployment of IT systems and interfaces required to implement the WEM Reform Program
- increased depreciation and amortisation associated with WEM reform.

Revenue requirement and fees

Fees and charges for WEM and GSI functions are based on the Economic Regulation Authority (ERA) determination of allowable revenue and forecast capital expenditure for the three-year period covering FY23-FY25. In WEM, the FY24 budgeted revenue reflects 50% of the remainder of the allowable revenue for this regulatory period. Further detail of Western Australia's fees is available at 5.4 Western Australia (WA) fees. Revenue for the retail gas market is determined on a cost-recovery basis, taking into account any accumulated funding position.

4.5. Victorian Transmission Network System Planning (Vic TNSP)

Purpose

AEMO has a unique role in Victoria, as we are responsible for ensuring the Victorian transmission network is developed in an efficient manner that will ultimately benefit all Victorian electricity consumers.

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: Victorian network users.

Segment health

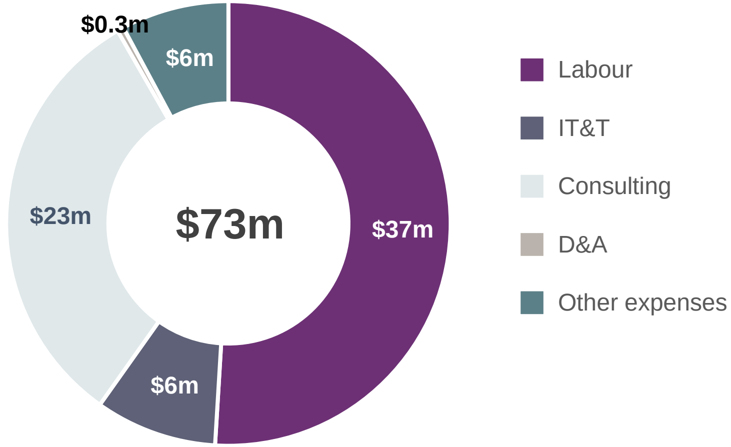
The revenue requirement and Transmission Use of System (TUoS) fees for Vic TNSP was determined in March 2023 in line with the requirement to publish TUOS prices. AEMO determined its TUoS fees ($650.2m, a 4.2% increase) in March 2023 in line with the publication requirement of the Shared Transmission Network Services Prices in Victoria – 1 July 2023 to 30 June 2024. The TUoS prices are calculated in accordance with AEMO's pricing methodology and the National Electricity Rules.

Vic TNSP Function profit and loss summary

	BUDGET FY23 ($M)	BUDGET FY24 ($M)	VARIANCE ($M)	VARIANCE (%)
Revenue	710.0	767.3	57.3	8.1%
Network Charges	(663.3)	(733.8)	(70.4)	10.6%
Net Revenue	46.6	33.5	(13.1)	(28.1%)
Operating costs	49.9	73.1	23.2	46.4%
Annual surplus/(deficit)	(3.3)	(39.5)	(36.3)	N/A
Accumulated surplus/(deficit)	**3.6**	**5.4**	**1.8**	**N/A**

Segment investment

Chart 7. Budgeted operating cost profile for Vic TNSP FY24, $M



Increases of $23m relates to higher costs of transmission activities, such as Victoria to NSW Interconnector (VNI) West, and the Western Renewable Link project (WRL), and an uplift in AEMO's internal resources and capability to effectively deliver the key responsibilities of the function.

4.6. AEMO Services Limited (ASL)

Purpose

AEMO Services Limited (ASL) is an independent subsidiary of AEMO, with an independent board, which carries out functions as appointed by National Electricity Market jurisdictions. ASL provides best-in-class energy and advisory services to member governments and their partners, supporting them to reshape our energy systems.

In its foundational role as the New South Wales (NSW) Consumer Trustee, an independent body appointed by the NSW Government, ASL acts independently and in the long-term financial interests of NSW electricity consumers. ASL is a key partner in the implementation of the *NSW Electricity Infrastructure Roadmap*, carrying out coordinated planning of long-term investment, managing competitive tenders to facilitate this investment, authorising Renewable Energy Zone transmission infrastructure, and provides financial risk management. This responsibility is at the core of everything we do.

Learn more about ASL.

Participants

The Crown in the right of the State of New South Wales (NSW).

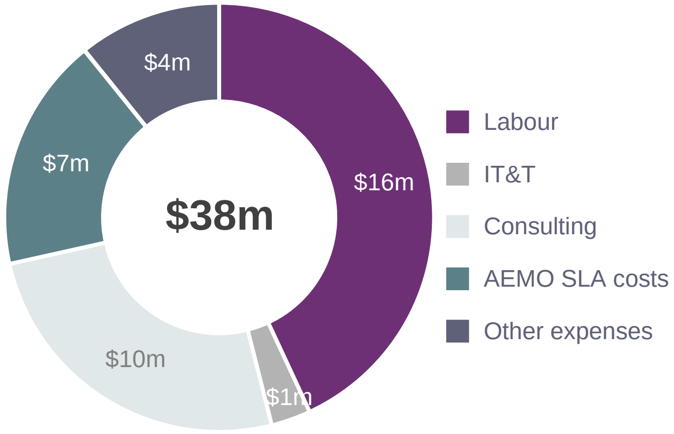
Financial health

ASL operates on a not-for-profit, full-cost recovery basis. It has specific funding arrangements to recover the cost of activities performed for NEM jurisdictions. As a separate entity, ASL's funding arrangements and budget are not covered in this document. Funding is provided via the NSW Electricity Infrastructure Fund. Ongoing funding requirements will be informed by an annual contributions determination process regulated by the Australian Energy Regulator (AER).

	BUDGET FY23 ($M)	BUDGET FY24 ($M)*	VARIANCE ($M)	VARIANCE (%)
Revenue	36.4	36.4	0.0	0.0%
Operating costs	36.4	38.1	1.7	4.6%
Annual surplus/(deficit)	-	(1.7)	(1.7)	N/A
Accumulated surplus/(deficit)	**10.1**	**2.2**	**(8.0)**	**N/A**

*FY24 based on Draft Budget. Final budget to be approved by ASL Board.

Investment



4.7. Profit and loss summary

AEMO's FY24 budget delivers a $24.1m in-year deficit overall. This reflects the return of accumulated surpluses (principally in the Victorian TNSP segment), partially offset by the reduction in the accumulated deficit in NEM Core.

Table 5 AEMO Group profit and loss summary

($M)	AEMO (EXCL. VIC TNSP)			VICTORIAN TNSP			AEMO		
	BUDGET FY23 ($M)	BUDGET FY24 ($M)	VARIANCE ($M)	BUDGET FY23 ($M)	BUDGET FY24($M)	VARIANCE ($M)(($M))	BUDGET FY23 ($M)	BUDGET FY24 ($M)	VARIANCE ($M)
REVENUE									
Fees and tariffs	378.5	391.1	12.6	-	-	-	378.5	391.1	12.6
TUoS income	(0.0)	-	0.0	623.9	650.2	26.2	623.9	650.2	26.3
PCF fees	0.1	-	(0.1)	-	-	-	0.1	-	(0.1)
Settlement residue	(0.0)	(0.0)	0.0	20.0	25.6	5.6	20.0	25.6	5.6
Other revenue	60.4	82.3	21.9	66.0	91.5	25.5	126.4	173.9	47.4
Network charges	-	-	-	(663.3)	(733.8)	(70.4)	(663.3)	(733.8)	(70.4)
NET REVENUE	**438.9**	**473.4**	**34.5**	**46.6**	**33.5**	**(13.1)**	**485.6**	**507.0**	**21.4**
OPERATING EXPENDITURE									
Labour	205.2	235.4	30.2	17.8	26.8	9.0	223.0	262.2	39.2
Consulting	33.4	36.3	3.0	10.7	21.3	10.6	44.1	57.6	13.5
IT & telecommunications	72.4	75.7	3.3	-	0.3	0.3	72.4	76.0	3.6
Occupancy	10.5	13.0	2.5	-	-	-	10.5	13.0	2.5
Other expenses	31.4	40.7	9.3	3.3	5.2	1.9	34.7	46.0	11.3
Depreciation and amortisation	69.0	61.6	(7.4)	0.1	0.3	0.2	69.1	61.9	(7.2)
Financing costs	9.4	17.7	8.3	-	(3.2)	(3.2)	9.4	14.4	5.0
Corporate recovery (TNSP)	(18.0)	(22.3)	(4.3)	18.0	22.3	4.3	-	(0.0)	(0.0)
TOTAL OPERATING EXPENDITURE	**413.2**	**458.0**	**44.8**	**49.9**	**73.1**	**23.2**	**463.1**	**531.1**	**68.0**
SURPLUS / (DEFICIT)									
Annual surplus / (deficit)	25.7	15.4	(10.3)	(3.3)	(39.5)	(36.3)	22.4	(24.1)	(46.6)
ACCUMULATED SURPLUS / (DEFICIT)	**(37.3)**	**44.7**	**82.0**	**3.6**	**5.4**	**1.8**	**(33.7)**	**50.1**	**83.8**

4.8. Balance sheet summary

The AEMO FY24 budget is for net assets to return to a positive position. The FY23 AEMO Group Consolidated balance sheet had a budgeted $12m negative net assets position, which was the result of an accumulated operating deficit driven by historic under recovery of costs for NEM Core from prior periods.

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. The reduction in cash and cash equivalents is driven by a reduction in participant security deposits on the assumption of stable conditions in energy market over the year ahead.

Current liabilities include participant security deposits liabilities, equivalent to the asset noted above.

Borrowings represent drawn debt from AEMO's commercial bank facilities. The borrowed funds are used to finance capital investment requirements and working capital requirements. A reduction in budgeted borrowings for FY24 reflects lower capital expenditure requirements in FY23 and 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's is committed to achieving a debt to assets ratio of under 100% and maintain a liquidity ratio above 50%.

Table 6 FY24 AEMO Group Consolidated Balance Sheet summary

	BUDGET FY23 ($M)	BUDGET FY24 ($M)	VARIANCE ($M)
ASSETS			
Cash and cash equivalents	210.6	137.1	(73.5)
Other current assets	145.0	149.8	4.7
Non-current assets	531.0	657.4	126.4
Total assets	**886.7**	**944.3**	**57.6**
LIABILITIES			
Current liabilities	355.3	313.2	(42.1)
Borrowings (non-current)	529.6	527.1	(2.5)
Other non-current liabilities	13.9	32.0	18.2
Total liabilities	898.7	872.3	(26.4)
Net assets	**(12.0)**	**72.0**	**84.0**
EQUITY*			
Capital contribution	7.1	7.1	-
Participant Compensation Fund reserve	10.7	10.7	(0.0)
Land reserve	3.9	4.1	0.2
Accumulated surplus/ (deficit)	(33.7)	50.1	83.8
TOTAL EQUITY*	**(12.0)**	**72.0**	**84.0**
RATIOS			
Debt / total assets	59.7%	55.8%	(3.9%)
Current assets / liabilities	100.1%	91.6%	(8.5%)

*Total equity includes non-controlling interest share of $3.0M (FY23) and $0.7M (FY24) relating to AEMO Services Limited. AEMO has 70% controlling interest in ASL.

4.9. 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 by 2025.

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 will go live from 1 October 2023. In parallel we are enabling Distributed Energy Resources and new technologies to be an integral part of the SWIS.

Four key investment programs are in progress across AEMO:

CAPITAL PROGRAM	AEMO PRIORITY ALIGNMENT
NEM and gas reforms, including the NEM Reform Program, Project EDGE, retail reforms and gas reforms	Priority 1, Priority 2
WA market reforms, including the WEM Reform Program and the WEM Distributed Energy Resources Program	Priority 1, Priority 2
Modernising market operations systems, including implementing the Operations Technology Roadmap, the forecasting roadmap and the cyber security program to meet the evolving energy market needs and to reduce operational risks.	Priority 1, Priority 2
Modernising business systems, including our enterprise resources planning system, to improve efficiencies and streamline core business processes.	Priority 4

Legend

- Priority 1: Operating today's systems and markets
- Priority 2: Navigating the energy future
- Priority 4: Evolving the way we work

Expenditure on these programs is mostly labour, consultancy and IT&T, reflecting the digital nature of these activities.

These investments programs also result in ongoing operating costs, including finance costs as they become operational.

Table 7 Investment profile for FY24

CAPITAL EXPENDITURE ($M)	BUDGET FY23 ($M)	BUDGET FY24 ($M)	VARIANCE ($M)	VARIANCE (%)
Reform (NEM and gas)	62.0	69.8	7.8	13%
WA market reform	32.9	36.2	3.3	10%
Modernising market operations systems	36.0	27.7	(8.3)	(23%)
Modernising business systems	44.4	41.2	(3.2)	(7%)
AEMO CAPITAL EXPENDITURE ($M)	**175.3**	**174.9**	(0.4)	(0%)
VNI West# initial works (within VIC TNSP segment)	-	26.6	26.6	N/A
CAPITAL EXPENDITURE ($M) *	**175.3**	**201.5**	26.2	15%

VNI West capital expenditure is budgeted within Transmission Company Victoria (TCV), a wholly owned subsidiary of AEMO, and will be recovered through the VIC TNSP segment.
* Gross of capital grants of $1.13M

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

4.10. 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 the 'smoothing' of capital costs to market participants 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
- seeking concessional debt facilities for specific initiatives

4.11. Cash flow summary

AEMO's FY24 budgeted cash flow is shown in Table 8 FY24 cash flow summary. The reduction in net cash flows from operating activities is due to higher payments to suppliers and employees, partially offset by receipts from customers in Vic TNSP and East Coast Gas.

The level of investment in intangible assets has increased due to the work on VNI West and is driven by energy transformation reform initiatives. Cash held has reduced, however AEMO has sufficient liquidity in the form of undrawn committed debt facilities.

Table 8 FY24 cash flow summary

	BUDGET FY23 ($M)	BUDGET FY24 ($M)	VARIANCE ($M)
Receipts from customers	463.4	498.8	35.4
Payments to suppliers and employees	(368.0)	(427.2)	(59.2)
Net interest and finance costs paid	(9.0)	(6.8)	2.2
Net receipts into Participant Compensation Fund	0.1	-	(0.1)
NET CASHFLOWS FROM OPERATING ACTIVITIES	**86.5**	**64.8**	**(21.7)**
Net receipt of participant security deposits	8.2	(5.3)	(13.5)
Net payments for intangible assets	(175.3)	(200.4)	(25.1)
NET CASHFLOWS FROM INVESTING	**(167.1)**	**(205.7)**	**(38.6)**
Net borrowings	27.4	65.1	37.7
Repayments of lease liabilities	(1.3)	(5.4)	(4.1)
NET CASHFLOWS FROM FINANCING	**26.1**	**59.8**	**33.6**
NET INCREASE/DECREASE CASH HELD	**(54.5)**	**(81.1)**	**(26.7)**

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

5. Revenue requirements and fees

The following tables present the revenue requirement and fees (excluding any applicable GST) that will apply from 1 July 2023 for each function.

5.1. 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. A reduction in forecast volumes has resulted in a lower revenue requirement of 3.0% inclusive of a minor update in volumes post the finalisation of the Vic TNSP allocation.

The FY24 budget is based on the *Step Change* scenario from the 2022 *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 2020, AEMO conducted a review of its current *Electricity Market Participant Fee Structure*. An outcome of this review was a change to the fee structure of the NEM. The change applies from 1 July 2023, with the following adjustments to allocated fees:

- 17.5% of the NEM fees to be levied on the Transmission Network Service Provider (TNSP) (FY23: 0%)
- 55.9% allocated to wholesale participants (FY23: 46%)
- 26.6% allocated to market customers (FY23: 54%) – a combination of $/MWh and $/NMI on a 50/50 basis (FY23: $/MWh).

In accordance with the National Electricity Rules, AEMO has published its participant fees for Transmission Network Service Providers in February 2023.

Table 9 NEM Core revenue requirement and fees FY24

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
NEM revenue requirement ($M)	195.76	201.72	5.96	3.0%
Consumption (GWh)	176,022	173,560	(2,462)	(1.4%)
Connection points (Million)	10.59	10.70	0.10	1.0%
NEM FEE BY PARTICIPANT TYPE				
Market customer fee ($/MWh)	0.75400	0.28255	(0.47145)	(62.5%)
Market customer fees ($ per connection point per week)	NA	0.08817	0.08817	100.0%
Wholesale participants allocation ($M)	63.00	78.93	15.93	25.3%
TNSP allocation ($M)	NA	25.11	25.11	100.0%
NEM benchmark fee# $/MWh	1.11220	1.16225	0.05005	4.5%
Participant Compensation Fund* ($M)	0.1	0	(0.1)	(100%)

* There is no requirement for collection of participant compensation fund (PCF) in FY24. 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 10 NEM Core revenue requirement breakdown

FUNCTION	RATE ($)	RECOVERY BASIS
NEM UNALLOCATED FEES (30%)		
Market customers	0.17434	MWh of customer load
Market customers	0.05440	Per connection point per week
NEM ALLOCATED FEES (70%)		
Market customers	0.10821	MWh of customer load
Market customers	0.03377	Per connection point per week
Wholesale participants	N/A	Daily rate calculated on 2022 capacity/ energy basis
Transmission Network Service Providers	N/A	Energy consumed for the latest completed financial year

5.2. NEM 'functions' fees

5.2.1. Electricity retail market

The FY24 electricity retail market revenue requirement and fees were updated to include the cost recovery relating to Consumer Data Right (CDR) Reforms in line with *the Structure of Participant Fees for the Consumer Data Right (CDR) Declared NEM Project*, partly offset by a return of accumulated surplus.

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

Table 11 Electricity retail market revenue requirement and fee

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
Electricity retail market revenue requirement ($M)	13.92	16.25*	2.34	17%
Connection points (Million)	10.59	10.70	0.10	1.0%
Electricity retail market fees ($ per connection point per week)	0.02519	0.02923	0.00404	16%

* Includes $2.33m relating to Consumer Data Right (CDR).

5.2.2. 5MS and Global Settlements (GS) compliance (5MS/GS) and IT upgrade

The FY24 5MS/GS/GS revenue requirement is 1.9% lower than FY23, reflecting a return of accumulated surplus.

The change of AEMO's *Electricity Market Participant Fee Structure* adjusts the revenue allocation between market customers and wholesale participants. Effective from 1 July 2023, market customers are allocated 82% (FY23: 87%) and wholesale participants are allocated 18% (FY23: 13%) of the revenue requirement. The basis of recovery for market customers is also changing to a combination of $/MWh and $/NMI on a 50/50 basis (FY23: $/MWh).

Table 12 5MS/GS revenue requirement and fee

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
5MS/GS revenue requirement ($M)	43.15	42.31	(0.84)	(1.9%)
Consumption (GWh)	176,022	173,560	(2,462)	(1.4%)
Connection points (Million)	10.59	10.70	0.10	1.0%
5MS/GS FEE BY PARTICIPANT TYPE				
Market customer fee ($/MWh)	0.21327	0.09996	(0.11332)	(53.1%)
Market customer fees ($ per connection point per week)	NA	0.03119	0.03119	100.0%
Wholesale participants allocation ($M)	5.6	7.6	2.0	35.8%
5MS/GS benchmark fee# ($/MWh)	0.24513	0.24379	(0.00134)	(0.5%)

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

5.2.3. Distributed Energy Resources Integration Program (DER)

The FY24 DER revenue requirement is 1.9% lower than FY23, reflecting a return of accumulated surplus.

The FY24 fee by participant type reflects the changes to AEMO's *Electricity Market Participant Fee Structure*, where the market customer fee is levied on $/MWh and $/NMI, a 50/50 basis effective from 1 July 2023 (FY23: $/MWh). The revenue allocation between market customers and wholesale participants is unchanged.

Table 13 DER revenue requirement

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
DER revenue requirement ($M)	5.24	5.14	(0.10)	(1.9%)
Consumption (GWh)	176,022	173,560	(2,462)	(1.4%)
Connection points (Million)	10.59	10.70	0.10	1.0%
DER FEE BY PARTICIPANT TYPE				
Market customer fee ($/MWh)	0.02382	0.01184	(0.01198)	(50.3%)
Market customer fees ($ per connection point per week)	-	0.00370	0.00370	100.0%
Wholesale participants allocation ($M)	1.05	1.03	(0.02)	(1.9%)
DER benchmark fee # $/MWh)	0.02977	0.02961	(0.00016)	(0.5%)

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

5.2.4. National Transmission Planner (NTP)

The FY24 NTP revenue requirement was published on 15 February 2023, as per the National Electricity Rule requirement. This fee applies to Coordinating Network Service Providers.

Table 14 National Transmission Planner revenue requirement

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
NTP revenue requirement ($M)	19.63	19.57	(0.06)	(0.3%)

5.2.5. 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 FY24 is set to remain consistent with FY23.
- 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 15 Other revenue requirement and fees

	BUDGET FY23 ($M)	BUDGET FY24 ($M)	VARIANCE ($)	VARIANCE (%)
SA planning	1.00	1.00	0.00	0.0%
Settlement Residue Auctions	0.75	0.74	(0.01)	(0.9%)
Consumer Data Platform	0.56	0.67	0.10	18.3%

5.3. East Coast Gas (ECG) fees

5.3.1. Declared Wholesale Gas Market (DWGM)

The DWGM revenue requirement for FY24 is 55.8% lower compared to FY23, reflecting additional income relating to the Wholesale Market Capacity Certificate Auction (CC auction) and the Dandenong LNG storage and liquefaction costs ($10.8 million), which are directly recovered from DWGM market customers.

The DWGM tariff for FY24 is 50% lower compared to FY23 driven by a reduction in forecast consumption in the budget year. The FY24 consumption forecast is based on the *Orchestrated Step Change (1.8°C)* scenario from the 2023 *Gas Statement of Opportunities* (GSOO). The GSOO forecasts reflect a decline in gas export volumes (29%), driven by lower gas production from facilities within the DWGM; this trend down is forecasted to continue in forward years. The forecasts also show a decrease (7%) in gas powered generation, and a smaller decline in residential and commercial consumption (5%) and industrial consumption (4%), due in part to increased electrification.

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 FY24, the meter fee is set at $1.41268 per meter per day, which is 6.3% higher compared with FY23 primarily reflecting the impact of cost inflation.

Table 16 DWGM revenue requirement and fees

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
DWGM revenue requirement (Energy tariffs) ($M)	27.90	12.33	(15.58)	(55.8%)
Gas consumption (TJ)	244,409	222,686	(21,723)	(8.9%)
Distribution meters (Avg)	1,084	1,087	3	0.2%
DWGM VARIABLE FEES				
Energy tariff ($/GJ withdrawn)	0.11071	0.05535	(0.05536)	(50.0%)
Distribution meter ($/day per meter)	1.32870	1.41268	0.08398	6.3%
Participant compensation fund (PCF)	0	0	0	0

Table 17 FY24 budget DWGM energy consumption

TJ	BUDGET FY23	FORECAST * FY23	BUDGET FY24
Residential and commercial	130,956	126,522	124,269
Industrial	64,870	65,434	62,049
Export	40,708	39,002	29,066
GPG	7,875	8,892	7,302
Total	244,409	239,851	222,686
% change	2.0%	(1.9%)	(8.9%)

* Forecast annual FY23 consumption as at February 2023.

5.3.2. Short-Term Trading Market (STTM)

The STTM revenue requirement for FY24 is $1.51m (32%) lower compared to FY23, reflecting a return of accumulated surplus and increase in consumption forecast in the budget year.

The STTM activity fee includes the STTM Market Operator Service (MOS) allocation fee. Excluding the STTM MOS fees, the activity fee is 30% lower to FY23, reflecting reduction to revenue requirement and increase in FY24 forecast consumption. STTM MOS revenue requirement is set to increase by $0.3m (or a 152.5% increase in fee), driven by the change to AEMO's cost recovery approach. Currently, AEMO is funding the MOS allocation cost in advance, in line with AEMO's financial principle – not for profit, not for loss.

The FY24 consumption is forecast to be 2.3% higher compared to FY23 budget, reflecting moderate growth in residential, commercial and industrial for the Adelaide and Sydney hubs. For the Brisbane hub, a decline in industrial consumption is forecasted due to the closure of Incitec Pivot's Gibson Island facility from January 2023, partly offset by growth in residential and commercial load. The FY24 forecast consumption is based on the *Orchestrated Step Change (1.8°C)* scenario from the 2023 GSOO.

Table 18 STTM revenue requirement and fees

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
STTM revenue requirement ($M)	4.73	3.22	(1.51)	(32.0%)
Gas consumption (TJ)	140,909	144,211	3,302	2.3%
STTM VARIABLE FEES ($/GJ withdrawn)				
Activity fee	0.03382	0.02686	(0.00696)	(20.6%)
Activity fees (excluding STTM MOS)	0.03202	0.02231	(0.00971)	(30.3%)
STTM MOS allocation fee	0.00180	0.00455	0.00275	152.5%
PARTICIPANT COMPENSATION FUND (PCF)				
PCF Fee – Syd ($/GJ withdrawn per hub per ABN)	0	0	0	0
PCF Fee – Adel ($/GJ withdrawn per hub per ABN)	0	0	0	0
PCF Fee – Bris ($/GJ withdrawn per hub per ABN)	0	0	0	0

Table 19 STTM energy consumption

TJ	BUDGET FY23	FORECAST * FY23	BUDGET FY24
Adelaide	18,534	19,818	19,544
Brisbane	33,356	29,431	26,387
Sydney	89,019	96,819	98,280
Total	140,909	146,068	144,211
Percentage change	(3.2%)	3.7%	2.3%

* Forecast annual 2022-23 consumption as at February 2023.

5.3.3. Victorian (VIC) retail gas market

The lower Victorian retail gas market revenue requirement in FY24 reflects a return of accumulated surplus.

Table 20 VIC retail gas market revenue requirement and fees

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
VIC retail gas market revenue requirement ($M)	1.68	1.38	(0.30)	(18.0%)
Customer supply points (Million)	2.29	2.31	0.02	1.0%
VIC retail gas market tariff ($ per customer supply point per month)	0.05650	0.04803	(0.00847)	(15.0%)

5.3.4. Queensland (QLD) retail gas market

The revenue requirement increased by 25.2% in FY24 principally reflecting recovery of an accumulated deficit, in addition to inflationary cost increases.

Table 21 QLD retail gas market revenue requirement and fees

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
QLD retail gas market revenue requirement ($M)	0.86	1.08	0.22	25.2%
Customer supply points (million)	0.24	0.23	(0.00)	(0.6%)
QLD retail gas market fee ($ per customer supply point per month)	0.28627	0.37219	0.08592	30.0%

5.3.5. South Australia (SA) retail gas market

The revenue requirement increased by 0.8%, reflecting increase in the overall number of customer supply points.

Table 22 SA retail gas market revenue requirement and fees

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
SA retail gas market revenue requirement ($M)	1.35	1.36	0.01	0.8%
Customer supply points (million)	0.49	0.50	0.00	0.8%
South Australia retail gas market fee ($ per customer supply point per month)	0.21905	0.21910	0.00005	0.0%

5.3.6. New South Wales (NSW) retail gas market

The revenue requirement decreased by 8.8%, reflecting the reflecting a return of accumulated surplus.

Table 23 NSW retail gas market revenue requirement and fees

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
NSW retail gas market revenue requirement ($M)	2.99	2.73	(0.26)	(8.8%)
Customer supply points (million)	1.79	1.77	(0.02)	(1.0%)
NSW retail gas market fee ($ per customer supply point per month)	0.13949	0.12555	(0.01394)	(10.0%)

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

The annual revenue requirement for this function has been set lower than its operating cost since FY2021 due the return of accumulated surplus. The level of surplus available in FY24 is lower than FY23. In addition, the increase in the FY24 revenue requirement reflects an increase in cloud cost ($0.5m) required to deliver the 2024 GSOO.

The FY24 producer fee is 60.8% higher than FY23, reflecting the increase in the revenue requirement noted above and a decline in PJ gas production[1] due to delays in production projects and revisions to production expectations.

Table 24 GSOO revenue requirement and fees

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
GSOO revenue requirement ($M)	1.94	3.00	1.07	55.0%
Gas producers' production (PJ)	2,078	2,015	(63)	(3.0%)
MIRNs basic meters - total (millions)	4.81	4.81	0.01	0.1%
GSOO FEES				
Producer fee ($ per GJ)	0.00028	0.00045	0.00017	60.8%
Retailer fee ($ per customer supply point)	0.02352	0.03589	0.01237	52.6%

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

5.3.8. 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 25 GSH revenue requirement and fees

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
GSH revenue requirement ($M)	1.70	2.05	0.35	20.8%
Gas consumption (TJ)	23,985	35,100	11,115	46.3%
TRADING PARTICIPANT FEES				
Fixed fee - on licence per annum	12,000	12,000	0	0.0%
Fixed fee - additional licence per annum	12,000	12,000	0	0.0%
Variable transaction fee - daily product fee ($/GJ)	0.03	0.03	0	0.0%
Variable transaction fee - weekly product fee ($/GJ)	0.02	0.02	0	0.0%
Variable transaction fee - monthly product fee ($/GJ)	0.01	0.01	0	0.0%
OTHER PARTICIPANT FEES				
Reallocation participants - fixed fee per annum	9,000	9,000	0	0.0%
Viewing participants - fixed fee per annum	3,600	3,600	0	0.0%

5.3.9. Operational Transportation Service (OTS) Code Panel

The revenue requirement is set lower in FY24 reflecting lower operating cost and a return of accumulated surplus in this function. The fee for FY24 is 49.9% lower than FY23, driven by an increase in total GJ gas consumption forecast in DAA.

Table 26 OTS Code Panel revenue requirement and fee

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
OTS revenue requirement ($M)	0.14	0.12	(0.02)	(15.5%)
OTS Code Panel ($/GJ)	0.00294	0.00147	(0.00147)	(49.9%)

5.3.10. Gas Capacity Trading Platform (CTP)

The fixed and variable fee for CTP is proposed to reduce by 31.2% in FY24 to encourage greater participation in this market.

Table 27 CTP revenue requirement and fees

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
Fixed fee - on licence per annum (commodity and capacity) ($)	12,000	12,000	0	0.0%
Fixed fee - on licence per annum (capacity only)	7,000	7,000	0	0.0%
TRADING PARTICIPANT FEES				
Variable transportation fee ($/GJ) Daily/ Weekly/ Monthly	0.00790	0.00544	(0.00246)	(31.2%)
Variable compression fee ($/GJ) Daily/ Weekly/ Monthly	0.00790	0.00544	(0.00246)	(31.2%)

Note: the variable transaction fees for CTP includes a fee of $0.00147 relating to OTS Code Panel.

5.3.11. Day Ahead Auction (DAA)

Revenue requirement is higher in FY24 reflecting increasing GJ gas consumption forecast for the budget year. Participant fees, including fees relating to Operational Transportation Service (OTS) Code Panel, are lower in FY24, reflecting a reduction of 49.9% in OTS Code Panel fee and a general reduction of 10% in DAA fee driven by increase in total GJ gas consumption forecast.

Table 28 DAA revenue requirement and fees

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
DAA revenue requirement ($M)	1.38	2.32	0.94	68.1%
Gas consumption (GJ) - transportation	39,556	64,000	24,444	61.8%
Gas consumption (GJ) - gas compression	7,810	16,000	8,190	104.9%
TRADING PARTICIPANT FEES				
Other transportation fee ($/GJ)	0.03324	0.03139	(0.00185)	(5.6%)
Compression fee ($/GJ)	0.02818	0.02683	(0.00135)	(4.8%)

Note: the variable transaction fees for DAA includes a fee of $0.00147 relating to OTS Code Panel.

5.3.12. Gas Bulletin Board (GBB)

The revenue requirement is set 2.7% lower in FY24 to an accumulated surplus, while operational cost remaining stable for this function. Producer fees have been reduced by 3.2% reflecting the reduction in the revenue requirement. The Participant in wholesale gas market fee increased by 4.0% in FY24 due mainly to a reduction in the DWGM consumption forecast.

Table 29 GBB revenue requirement and fees

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
GBB revenue requirement ($M)	2.52	2.45	(0.07)	(2.7%)
Gas producer production (PJ) [2]	2,078	2,015	(63)	(3.0%)
Gas consumption (TJ)	385,318	366,897	(18,421)	(4.8%)
GBB FEES				
Producer ($/GJ)	0.00063	0.00061	(0.00002)	(3.2%)
Participants in wholesale gas market ($/GJ withdrawn)	0.00321	0.00334	0.00013	4.0%

[2] 2023 GSOO, Table 5 - Forecast of available annual production as provided by gas producers, 2023-27 (PJ)

5.4. Western Australia (WA) fees

5.4.1. WA Wholesale Electricity Market (WEM)

The WEM revenue requirement for FY24 is set to increase by $14.18m (33.9%) compared to FY23, and is consistent with the Allowable Revenue – Period 6 (AR6) determination. The increase in the revenue requirement reflects an operating expenditure increase driven by the WEM Reform and the WA DER projects.

The FY24 forecast consumption is in line with FY23. The forecast assumption is based on the *expected* scenario from the 2023 WEM Electricity Statement of Opportunities, which is currently under development.

AEMO anticipates making an in-period budget submission to the Economic Regulation Authority (ERA) in relation to WEM reform, which could impact the FY24 budget for this segment.

Table 30 WEM revenue requirement and Fees

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
WEM revenue requirement ($M)	41.90	56.08	14.18	33.9%
Energy consumption (GWh)	17,950	17,948	(2)	(0%)
WEM FEES				
WEM market operator fee ($/MWh)	0.4913	0.6868	0.19551	39.8%
WEM system management fee ($/MWh)	0.6646	0.8395	0.17489	26.3%
WEM fee ($/MWh) #	1.1559	1.5263	0.37041	32.0%
WEM fee (indicative benchmark) * ($/MWh)	2.3118	3.0526	0.74082	32.0%
WEM REGULATOR & COORDINATOR FEES ($/MWh)				
WA Economic Regulation Authority – Regulator fee	0.1727	0.2063	0.0336	19.5%
Energy Policy WA – Coordinator fee	0.0718	0.0779	0.0061	8.5%

WEM fee applies to Market Customers and Generators.

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

5.4.2. Western Australian Gas Services Information (GSI)

The GSI revenue requirement for FY24 is set to increase to $1.61m (3%), reflecting an increase in operating cost mainly driven by inflation. The GSI revenue requirement is determine by the ERA and is tracking within the Allowable Revenue – Period 6 (AR6) determination.

Table 31 GSI revenue requirement and fees

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
GSI revenue requirement ($M)	1.56	1.61	0.05	3.0%
WA Economic Regulation Authority – Regulator fee ($M)	0.15	0	(0.15)	(100%)
Energy Policy WA – Coordinator fee ($M)	0.16	0.15	(0.01)	(0.03%)

5.4.3. Western Australia (WA) retail gas market

The WA retail gas market revenue requirement include annual member fees. For FY24, the revenue is set to reduce by 2.1% due to a funding 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

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
WA retail gas market gas revenue requirement ($M)	1.46	1.43	(0.03)	(2.1%)
Customer supply points (Million)	0.80	0.81	0.01	1.6%
WA FRC GAS FEES				
WA retail gas market fee ($ per customer supply point per month)	0.12286	0.12290	0.00004	0.0%
Annual fee – member	22,434	24,009	1,575	7.0%
Annual fee - associate member	4,375	4,682	307	7.0%

Note: associate members are self-contracting users that are partly to the WA Gas Retail Market Agreement. The FY24 registration and annual fees are calculated according to clause 362A(5) of the Retail market Procedures (WA)

5.5. Victorian Transmission Network Service Provider (TNSP) fees

TNSP Transmission Use of Systems (TUoS) fees were published in March 2023. 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 32 Victorian Transmission Network Service Provider revenue requirement

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
TUoS revenue requirement ($M)	623.9	650.2	26.2	4.2%

5.6. 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.

5.6.1. Fee schedule of new registrations

Table 33 Fee schedule of new NEM registrations ($ per registration)

Fees are rounded to the nearest $50.

APPLICATION TYPE	BUDGET FY23 ($)	BUDGET FY24 ($)	VARIANCE ($)	VARIANCE (%)
Registration as scheduled market generator [A]	25,011	26,400	1,389	5.6%
Registration as semi-scheduled market generator	33,710	35,600	1,890	5.6%
Registration as non-scheduled market generator	21,748	22,950	1,202	5.5%
Registration as scheduled non-market generator	18,486	19,550	1,064	5.8%
Registration as semi-scheduled non-market generator	28,273	29,850	1,577	5.6%
Registration as non-scheduled non-market generator	15,224	16,100	876	5.8%
Transfer of registration	11,962	12,650	688	5.8%
Registration as market customer	11,962	12,650	688	5.8%
Registration as market small generation aggregator	11,962	12,650	688	5.8%
Registration as network service provider	10,874	11,500	626	5.8%
Registration as metering coordinator (MC) [B]	11,962	12,650	688	5.8%
Registration as trader	15,224	16,100	876	5.8%
Registration as reallocator	14,136	14,950	814	5.8%
Registration as an intending participant	6,525	6,900	375	5.7%
Classification of a dedicated connection asset	5,437	5,750	313	5.8%
Exemption from registration	6,525	6,900	375	5.7%
FREQUENCY CONTROL ANCILLARY SERVICES				
Classification of generating units as frequency control ancillary services (FCAS) generating units [B]	10,874	11,500	626	5.8%
Classification of load as frequency control ancillary services load – new ancillary services or classify load in a new region [C]	10,874	11,500	626	5.8%
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	2,175	2,300	125	5.7%
WHOLESALE DEMAND RESPONSE				
Registration as demand response service provider	17,399	18,400	1,001	5.8%
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	11,500	626	5.8%
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	2,300	125	5.7%
Aggregation of existing load already classified as wholesale demand response unit	2,175	2,300	125	5.7%

APPLICATION TYPE	BUDGET FY23 ($)	BUDGET FY24 ($)	VARIANCE ($)	VARIANCE (%)
DISBURSEMENT CHARGES				
Disbursement charge – additional energy conversion model – semi scheduled market generator	5,437	5,750	313	5.8%
Disbursement charge – additional energy conversion model – non-scheduled market generator	2,719	2,900	181	6.7%
STAND ALONE POWER SYSTEM				
New participant as a market stand-alone power system resource provider (MSRP)	12,461	13,150	689	5.5%
Existing market participant registering as a market stand-alone power system resource provider (MSRP)	8,168	8,650	483	5.9%

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.
Note: Registration fee as a Market Stand-alone Power Systems Resource Provider (MSRP) will be applied from 30 May 2023.

Table 34 Fee schedule of new WA WEM registrations ($ per registration)

APPLICATION TYPE	BUDGET FY23 ($)	BUDGET FY24 ($)	VARIANCE ($)	VARIANCE (%)
Rule participant registration application fee	2,450	2,650	200	8.2%
Facility registration application fee	4,550	4,900	350	7.7%
Facility transfer application fee	2,450	2,650	200	8.2%
Conditional certification of reserved capacity	1,230	1,350	120	9.8%
Resubmission - application for early certified reserved capacity	11,250	12,050	800	7.1%
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)	550	600	50	9.1%

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

Table 35 Fee schedule of new power of choice accreditations ($ per application)

APPLICATION TYPE	BUDGET FY23 ($)	BUDGET FY24 ($)
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 40 AEMO charge-out rates ($ per hour)	

Table 36 Fee schedule of new gas registrations

Fees are rounded to the nearest $50.

MARKET	APPLICATION TYPE	BUDGET FY23 ($)	BUDGET FY24 ($)	VARIANCE ($)	VARIANCE (%)
Victoria Retail Gas	Market participant - retailer	20,661	21,800	1,139	5.5%
	Market participant - functions	20,661	21,800	1,139	5.5%
QLD Retail Gas	Retailer	18,486	19,550	1,064	5.8%
	Self-contracting user	18,486	19,550	1,064	5.8%
SA Retail Gas	Retailer	17,399	18,400	1,001	5.8%
	Self-contracting user	17,399	18,400	1,001	5.8%
NSW Retail Gas	Retailer	20,661	21,800	1,139	5.5%
	Self-contracting user	20,661	21,800	1,139	5.5%
WA Retail Gas	WA retail gas - member	13,904	14,880	976	7.0%
	WA retail gas - associate member	2,780	2,975	195	7.0%
DWGM	Market participant - retailer	21,084	22,250	1,166	5.5%
	Market participant - trader	21,084	22,250	1,166	5.5%
	Market participant - distribution centre	20,469	21,600	1,131	5.5%
STTM	STTM user (BRI, ADL, SYD hubs)	21,392	22,600	1,208	5.6%
	STTM shipper (BRI, ADL, SYD hubs)	21,392	22,600	1,208	5.6%
	STTM allocation agent	17,394	18,400	1,006	5.8%
	STTM pipeline operator	37,382	39,450	2,068	5.5%
	STTM distributor	37,074	39,150	2,076	5.6%
	STTM storage facility operator	37,382	39,450	2,068	5.5%
	STTM production facility operator	37,382	39,450	2,068	5.5%
Pipeline Capacity	Part 24 facility operator	16,311	17,250	939	5.8%
	Day ahead auction – auction participant	16,311	17,250	939	5.8%
Gas Bulletin Board	BB allocation agents	16,311	17,250	939	5.8%
	BB transportation facility user	11,962	12,650	688	5.8%
	BB capacity transaction reporting agents	11,962	12,650	688	5.8%

Note: the above registration fees are per registration per registrable capacity in exception to Gas Bulletin Board, which is per registration.

Table 37 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

5.6.2. Other fees

Table 38 Other fees

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
NEMDE queue ($ per application)	15,836	16,750	914	5.8%
Project developer ($ per facility)	6,524	6900	376	5.8%
Voluntary book build participant accreditation fee ($ per application)	897	950	53	5.9%
Additional participant ID ($ per additional ID)	5,807	6150	343	5.9%

5.6.3. 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 39 AEMO charge-out rates ($ per hour)

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
Senior leadership	510	530	20	3.9%
Manager/ specialist	430	440	10	2.3%
Principal	340	350	10	2.9%
Senior	300	320	20	6.7%
Analyst/ engineer	280	300	20	7.1%
Office/ intern	240	250	10	4.2%

5.7. 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 FY24, ECA has budgeted to collect $9.28m (FY23: $8.28m).

The electricity ECA fee for FY24 is $0.01260 per connection point for small customer per week, a 14.1% increase compared with FY23, reflecting increases in funding requirements (10%), combined with a lower return of prior year surplus funds. This fee is applicable to Market Customers.

The gas ECA fee for FY24 is $0.03548 per customer supply point per month, 9.6% lower compared with FY23. The fee reduction driven by return of prior year surplus, partly offset by an increased funding requirement (10%). 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 40 ECA revenue requirement and fees

	BUDGET FY23	BUDGET FY24	VARIANCE ($)	VARIANCE (%)
ELECTRICITY				
Revenue requirement ($M)	6.02	6.92	0.90	15.0%
Electricity retail market - connection points for small customers	10.59	10.56	(0.03)	(0.3%)
Electricity ($/connection point for small customers per week)	0.01104	0.01260	0.00156	14.1%
GAS				
Revenue requirement ($M)	2.26	2.05	(0.21)	(9.3%)
MIRNs basic meters - total (millions)	4.81	4.81	0.00	0.1%
Gas ($/customer supply point per month)	0.03925	0.03548	(0.00377)	(9.6%)

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 41 Segment, function and function purpose

FUNCTION	SUMMARY OF RESPONSIBILITIES[3]
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 Auction 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 2025 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.

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

FUNCTION	SUMMARY OF RESPONSIBILITIES[4]
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.
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.
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.

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

FUNCTION	SUMMARY OF RESPONSIBILITIES[4]
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

TERM	DEFINITION
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

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AUSTRALIAN ENERGY MARKET OPERATOR