2020-21 AEMO Draft Budget and Fees

Introduction and overview

AEMO is a not-for-profit company limited by guarantee, with government and industry members. AEMO receives no ongoing Government funding but recovers its operating and capital expenses through approximately 20 different fees levied to participants. Each fee is limited to recovering the costs of providing that particular service.

AEMO sets its budget on an annual basis and is providing this draft to enable industry feedback, consideration and consultation to occur. This document focuses on the draft 2020-21 budget and fees that will support the provision of services across all of AEMO's functions. Further, in July 2020, AEMO will publish its annual Corporate Plan that will detail the activities, priorities and key performance indicators for AEMO for the financial year.

AEMO's current fee structure expires 30 June 2021. As required by the National Electricity and Gas Rules, AEMO will initiate a separate consultation in July 2020 to discuss with market participants and other stakeholders an optimum fee structure to commence in July 2021. In addition to specific consultation on the structure of participant fees, AEMO is also proposing to explore with stakeholders in the upcoming year, potential changes to AEMO's business and financial model to make it less debt reliant and enable AEMO and industry participants to collaboratively consider opportunities to remove costs from the energy value chain.

Financial summary

Labour-related expenses and IT, forecasting and operating system maintenance, and investments required to plan and operate Australia's electricity and gas systems and markets represent the bulk of AEMO's expenses. AEMO funds its technology-related investments through debt borrowings and participants' fees are set to recover the debt over the life of the asset. Where possible, AEMO also seeks grant funding for some of its capital investments.

AEMO's operating and capital budgets reflect the direct impact the significant transformation occurring in the energy industry is having on the organisation. For example, the volume of rule changes in the NEM has tripled in the past three years and virtually all the rule changes directly impact AEMO. Along with implementation expenses associated with rule and market changes, the obligations and technology investments associated with system planning, cyber security protections, connections analysis and commissioning, market and operations consultation, and compliance reporting have increased.

Moreover, the sheer complexities associated with planning and operating systems with the rapid changes and dependence on variable renewable and distributed resources, along with the forecasting and analysis of the operating capabilities of aging thermal resources, have required increases in both personnel and capital investments in the systems AEMO uses to forecast, model and operate the power systems.

Apart from these requirements, after a decade of operations, AEMO's existing information architecture was no longer capable of keeping up with both the data requirements and speed required to meet the needs of the sector. Absent the requisite investment, AEMO's technology platforms and systems will not be capable of meeting the changing needs of Australia's energy systems.

AEMO is now in the second year of a five-year program to replace its aging systems with a digital system that will increase the cost-effectiveness of its operations, such as reducing the timing of implementation and transactional costs, taking advantage of cloud computing, and more efficiently meeting participant and consumer information needs.

The COVID-19 pandemic is impacting AEMO's actual and forecast revenue, due to falling electricity demand reducing total MWh volumes. AEMO has managed this impact on its revenue to date through reductions in operating costs and improved use of technology. Based on best current estimates, AEMO expects to be able to continue to manage the forecast reduction in revenue into 2020-21, however this will be dependent on the impact of the pandemic on the broader economy.

While the above drivers impact AEMO's largely fixed costs, AEMO wants to make certain that it is operating efficiently and adding value for what is ultimately the consumer's energy dollar. To this end, AEMO is undertaking a comprehensive review of both its ways of working and its approaches to technology investment. This review will be supported through an external consultancy and is expected to drive further efficiencies and become part of the operating model adopted to guide AEMO's future operations.

Draft budget

AEMO's draft budget for 2020-21 is $250.4 million, and its accumulated deficit at the end of the fiscal year (excluding the Victorian transmission network service provider [TNSP] function) is estimated to be $67.1 million. AEMO requires approximately $500 million to fund capital investments in its operating systems in coming years, and has secured debt facilities for this purpose, with the costs recovered over the useful life of each asset.

For many markets and services that AEMO operates, fees will decline in the coming year. Across 11 fee sets, AEMO is pleased to be able to provide for a reduced fee in 2020-21. However, for connections and registrations, NEM fees, and some other fee categories, increases are projected.

Given the rate of change occurring across the NEM in both markets and operations, in 2018 AEMO elected to cap the rate of its NEM fee increases to 12% a year to mitigate the impact on participants. The accumulated deficit reflects the delay in recovery of AEMO's costs that are the result of this voluntary fee cap.

The table below provides a summary of the draft 2020-21 profit and loss and accumulated surplus/(deficit) position, in comparison to the 2019-20 budget.

Table 1 Summary profit and loss

Profit and loss ($m)	AEMO (ex Vic TNSP) 2019-20 Budget	AEMO (ex Vic TNSP) 2020-21 Budget	Variance	Vic TNSP 2019-20 Budget	Vic TNSP 2020-21 Budget	Variance
Net revenue	198.4	222.6	24.2	19.1	34.3	15.2
Operating expenditure	235.6	250.4	14.8	22.3	31.0	8.7
Surplus/(deficit)	(37.3)	(27.7)	9.6	(3.2)	3.3	6.5
Acc. surplus/(deficit)	**(42.0)**	**(67.1)**	**(25.1)**	**(0.1)**	**(0.9)**	**(0.8)**

Capital program

AEMO's planned capital expenditure relates primarily to:

- A refresh of information technology systems that are nearing end-of-life, end-of-service with a digital capability.
- Ongoing maintenance and improvements of legacy systems, including licensing fees.
- Enhancements to cyber security, forecasting, modelling, and operational decision analysis tools.
- The design and implementation of the technical integration of DER into the network.
- Regulatory compliance programs, including market implementations such as Five Minute Settlement (5MS) and Global Settlements.

Table 2 is a summary of the capital program.

Table 2 Capital program summary

Capital Expenditure ($'m)	2019-20 and prior	Budget 2020-21	Estimate 2021-22	Estimate 2022-23
Digital Platform, System and Cyber Refresh and ongoing maintenance	104.6	87.4	73.3	83.0
DER Integration – Net of estimated Govt funding	21.6	20.4	(2.3)	1.4
Regulatory Compliance Programs	43.2	56.2	25.0	18.4
Net Capital Expenditure	**169.4**	**164.0**	**96.0**	**102.8**

Further detail is provided in Section 3 of this document.

Impact on fees

AEMO has a number of separate functions, of which operating the systems and markets in the National Electricity Market (NEM) is the largest. Each function has its own fees, which are set in accordance with published fee structures. Fees are set on a cost recovery basis, and new initiatives and any under-recovery are funded via a debt facility.

The key points of the 2020-21 draft fees are:

- Most gas fees will be decreasing in 2020-21.

As foreshadowed last year, the NEM fee is increasing by 12% in line with the estimate provided, drven by the factors outlined above:

- Western Australian fees are aligned to the allowable revenue approved by the Western Australian Economic Regulation Authority (ERA).
- National Transmission Planner fees are increasing as a result of AEMO's expanded role to deliver an actionable Integrated System Plan (ISP). The costs associated with the development of the first actionable ISP will continue to be reviewed and refined.
- The Victorian TNSP fees are increasing, predominantly due to costs relating to the procurement of Western Murray System Strength Remediation services, operating costs linked with the Western Victoria Renewable Integration project, and a ramp up in regulatory investment activities associated with the Victoria to New South Vales Interconnector (VNI) West project.

Expenses and fees beyond 2020-21

There are a number of factors that may impact fees beyond 2020-21, which include:

- As the current determinations on the structure of participant fees for both electricity and gas conclude on 30 June 2021, AEMO will be undertaking an extensive consultation to determine new structures for participant fees for future years that will consider the evolving nature of the energy system and the services that AEMO provides in accordance with the principles set out in the relevant rules.
- New regulatory developments, which are being considered by the Energy Security Board (ESB) and the Australian Energy Market Commission (AEMC) through the rule change process. For instance, this would include the timing of the introduction of markets to procure demand response, and other potential changes including ahead, two-sided and essential security markets.
- Unforeseen revenue and system impacts, as well as new responsibilities, as a result of the COVID-19 pandemic and its aftermath.

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1. Fees

1.1 National Electricity Market

Purpose of this function	**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)**
Fees	The projected NEM fee for 2020-21 is $0.56/MWh (+12%). As projected in last year's budget process, the NEM fee is increasing by 12% in 2020-21, reflecting the need for additional investment as well as smoothing the recovery of costs over a longer period. As detailed above, the additional investment is being driven by: • Increased system and market complexity • Increased compliance obligations • Increased stakeholder engagement and reporting requirements The costs associated with the Five Minute Settlement (5MS) project are not included, as cost recovery is not expected to commence before 2021-22.

Table 3 NEM projected fees (indicative benchmark)

Fee	Actual 2019-20	Budget 2020-21
NEM fee $/MWh)	0.50	0.56 +12%

AEMO's costs represent approximately 0.2% - 0.3% of an average household electricity bill.

This equates to a cost of approximately $4 per customer per year.*

* Key assumptions:

- 10m NMIs in the NEM of which 8,8m are households, 1.1m small businesses and 0.1m large businesses.
- 57% of consumption relates to large business, 28% to households and 15% to small business.
- Consumption of less than 10Mwh per annum is considered a household.

1.1.1 NEM energy consumption

NEM consumption is forecast to decline in 2020-21, reflecting the current best estimate as a result of the economic slowdown due to COVID-19. This in turn impacts those elements of the NEM fees that are linked to energy consumption.

The budgeted consumption for 2020-21 is based on recent estimates adjusted for COVID-19 and will be updated in the Final Budget and Fees document. Table 4 below outlines the budget energy consumption used to calculate the NEM fee. This fee will be reviewed for the reasons indicated in the Introduction and overview.

Table 4 NEM consumption

GWh	Budget 2019-20	Forecast* 2019-20	Budget 2020-21
NEM	179,387	178,270 -0.6%	174,472 -2.7%

* Forecast annual consumption at May 2020.

1.2 Full Retail Contestability (FRC) Electricity

Purpose of this function	**To facilitate retail market competition in the east coast and southern states of Australia by managing and supporting:** • **Data for settlement purposes** • **Customer transfers** • **Business to business processes** • **Market procedure changes**
Fees	The projected FRC Electricity fee for 2020-21 will remain unchanged at $0.02550 per connection point per week.

Table 5 FRC electricity projected fees

Fee	Actual 2019-20	Budget 2020-21
$ per connection point per week	0.02550	0.02550 0%

1.3 National Transmission Planner (NTP)

Purpose of this function	**Delivering an actionable Integrated System Plan (ISP)**
Fees	On 1 July 2020, the ISP will replace the initial stages of the RIT-T process, providing a ready-made modelling suite with assumptions, transparent justifications for actionable projects and greater certainty of success once a project has been determined actionable. The plan will also include Renewable Energy Zones for the first time. The above changes along with prior year under-recovery of NTP costs has increased the proposed fee for 2020-21. The costs associated with the development of the first actionable ISP will continue to be reviewed and refined.

Table 6 National Transmission Planner projected revenue requirement and operating costs

($m)	Budget 2019-20	Budget 2020-21
Revenue requirement	$5.5m	$20.1m
Annual operating costs	$10.1m	$16.0m

1.4 Victorian Electricity Transmission Network Service Provider (TNSP)

Purpose of this function	• **AEMO provides shared transmission network services to users of the Victorian Declared Transmission System (DTS).** • **These services include the planning of future requirements and procuring of augmentations in the DTS.**
Fees	Transmission Use of System (TUOS) fees are calculated on an annual break-even basis, and are predominately influenced by network charges billed by the Victorian electricity transmission network owners and by estimations of settlement residue receipts. The projected fees for 2020-21 are 7.6% higher than the 2019-20 fees, mainly due to: • An increase relating to procurement of Western Murray System Strength Remediation services, operating costs linked with the Western Victoria Renewable Integration project, and a ramp up in regulatory investment activities associated with the Victoria to New South Vales Interconnector (VNI) West project; and • Lower settlement residue income for the Victorian region as a result of lower estimated spot prices, partly offset by higher estimated Settlement Residue Auction proceeds.

Table 7 Projected TUOS revenue requirement

Fee	Actual 2019-20	Budget 2020-21
TUOS fees ('000)	549,555	591,499 +7.6%

1.5 Western Australia Wholesale Electricity Market (WEM)

Purpose of this function	• **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**
Fees	The current WEM fee is $0.861/MWh. This fee is proposed to increase to $0.906 (+5%) in 2020-21 in line with the prior year estimate. The proposed increase is as a result of additional activities and complexity in the WEM including ongoing system management transition work. This increase is in line with the ERA's allowable revenue determination.
Other notes	The current three-year ERA determination on AEMO's allowable revenue and capital expenditure covers the period from 1 July 2019 to 30 June 2021.

Table 8 WA WEM fees

Fee	Actual 2019-20	Budget 2020-21
WEM Market Operator fee ($/MWh)	0.362	0.387 +7%
WEM System Management fee ($/MWh)	0.499	0.519 +4%
WEM fee ($/MWh)	0.861	0.906 +5%
WEM fee (indicative benchmark) * ($/MWh)	1.722	1.812

* The fee listed above is a benchmark fee calculated by dividing the total cost of the WEM functions by the total forecast consumption. The actual fee charged to both Market Customers and Generators is $0.387/MWh and 0.519/MWh for the Market Operations and System Management functions respectively.

1.5.1 WEM energy consumption

Consumption is expected to decrease by 3.5% in 2020-21 due to the impact of an expected economic slowdown as a result of COVID-19, continued increases in rooftop PV, and lower industrial load forecast.

Table 9 WEM consumption

GWh	Budget 2019-20	Forecast* 2019-20	Budget 2020-21
Load forecast	18,221	17,672 -3.0%	17,589 -3.5%

* Forecast annual consumption at May 2020.

1.6 Declared Wholesale Gas Market (DWGM)

Purpose of this function	**To enable competitive dynamic trading based on injections and withdrawals from the transmission system that links producers, major users and retailers** **This market provides the following broad services:** • **Gas system security, market operations and systems** • **Gas system reliability and planning** • **Wholesale metering and settlements** • **Prudential management**
Fees	**Energy tariff** The current energy tariff is $0.08713/GJ. This fee is proposed to increase by 2% to $0.08887/GJ in 2020-21. The fee increase is driven by lower forecast energy consumption in 2020-21. **Distribution meter fee** The distribution meter fee is paid by each market participant connected to a Declared Distribution System, or whose customers are connected to a Declared Distribution System, at a connection point which there is an interval metering installation. The distribution meter fee relates to metering data services and is proposed to decrease by 6% to $1.28580 per meter per day in 2020-21 to return a prior year surplus. **Participant Compensation Fund** The Participant Compensation Fund fee is not required to be charged in 2020-21, as the current level of DWGM PCF funds being held meets the Rules requirement.

Table 10 Projected DWGM fees

Fee	Actual 2019-20	Budget 2020-21
Energy tariff ($/GJ)	0.08713	0.08887 +2%
Distribution Meter ($/day per meter)	1.36970	1.28580 -6%
PCF Fee ($/GJ)	0	0

1.6.1 DWGM energy consumption

The budgeted consumption for 2020-21 is based on data used in the March 2020 Gas Statement of Opportunities (GSOO) with updated information to reflect the current outlook.

Table 11 DWGM energy consumption

TJ	Budget 2019-20	Forecast * 2019-20	Budget 2020-21
Domestic	126,870	131,430	127,993
Industrial	65,609	66,821	65,745
Export	41,982	34,192	22,909
GPG	4,519	15,009	14,553
Total	238,980	250,451	231,200
		+4.8%	-3.3%

* Forecast annual 2019-20 consumption at May 2020.

1.7 Short Term Trading Market (STTM)

Purpose of this function	**To enable a wholesale market gas balancing mechanism at the gas hubs – Sydney, Adelaide and Brisbane** **The market is a day ahead market for each hub, and the market sets a daily market price** **The STTM function provides the following broad services:** • **Market operations and systems** • **Market Operator Service (MOS) – AEMO recovers the pipeline operators' service costs for their portion of operating costs in relation to the STTM and recovers this from participants** • **Wholesale metering and settlements** • **Prudential management**
Fees	The current STTM fee is $0.04258/GJ. This fee is proposed to decrease by 13% to $0.03684/GJ in 2020-21 as the costs associated with the establishment of the STTM have been fully recovered. **Participant Compensation Fund** The Participant Compensation Fund fee is not required to be charged in 2020-21, as the current level of STTM PCF funds being held meets the Rules requirement.

Table 12 Projected STTM fees

Fee	Actual 2019-20	Budget 2020-21
Activity Fee ($/GJ withdrawn)	0.04258	0.03684 -13%
PCF Fee – Syd ($/GJ withdrawn per hub per ABN)	0	0
PCF Fee – Adel ($/GJ withdrawn per hub per ABN)	0	0
PCF Fee – Bris ($/GJ withdrawn per hub per ABN)	0	0

1.7.1 STTM energy consumption

The STTM energy consumption forecast is based on data used in the March 2020 GSOO, with updated information to reflect the current outlook. Forecast 2020-21 consumption is closely aligned to the 2019-20 forecast.

Table 13 Projected STTM energy consumption

TJ	Budget 2019-20	Forecast* 2019-20	Budget 2020-21
Adelaide	21,543	20,656	20,327
Brisbane	31,489	32,157	31,845
Sydney	92,239	91,047	91,265
Total	145,272	143,860	143,437
		-1.0%	-1.3%

* Forecast annual 2019-20 consumption at May 2020.

1.8 FRC Gas Markets

Purpose of these functions	To provide 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. The following broad services are provided: • Support retail market functions and customer transfers. • Manage data for settlement purposes. • Implement market procedure changes. • Operate the central IT systems that facilitate retail market services. (Operated in Victoria, Queensland, South Australia, New South Wales and Western Australia)

1.8.1 Victorian FRC Gas

Fees

The current Victorian FRC Gas fee is $0.06548 per customer supply point/month.

This fee is proposed to decrease to $0.06221 (down 5%) in 2020-21, due to a reduction in costs to provide this service.

Table 14 Projected Victorian FRC gas fees

Fee	Actual 2019-20	Budget 2020-21
FRC Gas Tariff ($ per customer supply point per month)	0.06548	0.06221 -5%
Initial Registration Fee ($ per participant)	19,000	19,570 +3%

1.8.2 Queensland FRC Gas

Fees

The current Queensland FRC Gas fee is $0.24482 per customer supply point/month. This fee is proposed to increase to $0.26441 in 2020-21. This fee has been reduced over recent years to return an accumulated surplus to participants, and the proposed increase reflects the fee returning to its base level.

Table 15 Projected Queensland FRC gas fees

Fee	Actual 2019-20	Budget 2020-21
FRC fee ($ per customer supply point per month)	0.24482	0.26441 +8%
Initial Registration Fee ($ per participant)	17,000	17,510 +3%

1.8.3 South Australia FRC Gas

Fees

The current South Australian FRC Gas fee is $0.20839 per customer supply point/month.

This fee is proposed to decrease to $0.20214 (down 3%) in 2020-21, due to a reduction in costs to provide this service.

Table 16 Projected South Australia FRC gas fees

Fee	Actual 2019-20	Budget 2020-21
FRC fee ($ per customer supply point per month)	0.20839	0.20214 -3%
Initial Registration Fee ($ per participant)	16,000	16,480 +3%

1.8.4 New South Wales FRC Gas

Fees	The current New South Wales (including Australian Capital Territory) FRC Gas fee is $0.15097 per customer supply point/month. This fee is proposed to decrease to $0.14040 (down 7%), due to system costs being fully amortised by end of 2020-21.

Table 17 Projected New South Wales FRC gas fees

Fee	Actual 2019-20	Budget 2020-21
FRC fee ($ per customer supply point per month)	0.15097	0.14040 -7%

1.8.5 Western Australia FRC Gas

Fees	The fee for 2020-21 is proposed to decrease by 5% to $0.12170, due to a reduction in costs to provide this service.

Table 18 Projected Western Australia FRC gas fees

Fee	Actual 2019-20	Budget 2020-21
FRC fee ($ per customer supply point per month)	0.12811	0.12170 -5%
Initial Registration Fee – member	13,163	13,435
Initial Registration Fee – associate member	2,632	2,686
Annual Fee – Member	20,231	20,649
Annual Fee - Associate Member	3,945	4,027

Note: associate members are self-contracting users that are party to the WA Gas Retail Market Agreement. The 2020-21 registration and annual fees are calculated according to clause 362A(5) of the Retail Market Procedures (WA).

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

Purpose of this function	**To report the supply adequacy of eastern and south-eastern Australian gas markets to meet energy needs – AEMO reports on demand and supply, and delivery constraints projected for the next 20 years** **Retailers across the FRC gas market jurisdictions are currently charged for GSOO costs at a flat rate per customer supply point**
Fees	The current GSOO fee is $0.03989 per customer supply point/month. This fee is proposed to decrease to $0.03869 (down 3%) in 2020-21, due to a reduction in costs to provide this service.

Table 19 Projected GSOO fees

Fee	Actual 2019-20	Budget 2020-21
GSOO ($ per customer supply point per month)	0.03989	0.03869 -3%

1.10 Gas Supply Hub (GSH)

Purpose of this function	**To provide an exchange for the wholesale trading of natural gas to enable improved wholesale trading for an east coast gas market affected by significant liquefied natural gas (LNG) exports in Queensland – through an electronic platform, GSH participants can trade standardised, short-term physical gas products at each of the three foundation pipelines connecting at Wallumbilla** **AEMO centrally settles transactions, manages prudential requirements and provides reports to assist participants in managing their portfolio and gas delivery obligations**
Fees	Fees are determined outside of AEMO's budget and fee setting process and are set within the Gas Supply Hub exchange agreement with consultation with stakeholders when changes are made. The GSH fee schedule is included in this report for information purposes.

Table 20 Projected GSH fees

Fee	Fee type	Actual 2019-20	Budget 2020-21
Trading participants	Fixed Fee - one licence per annum	12,000	12,000
	Fixed Fee - additional licence per annum	12,000	12,000
	Variable transaction fee		
	• Daily product fee ($/GJ)	0.03	0.03
	• Weekly product fee ($/GJ)	0.02	0.02
	• Monthly product fee ($/GJ)	0.01	0.01
Reallocation participants	Fixed fee per annum	9,000	9,000
Viewing participants	Fixed fee per annum	3,600	3,600

1.11 Gas Capacity Trading (CTP)

Purpose of this function	**To facilitate the secondary trading of pipeline capacity.** **The following broad services are provided:** • **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.**
Fees	There is minimal change proposed to the fees for 2020-21.

Table 21 Projected CTP fees

Fee	Fee type	Actual 2019-20	Budget 2020-21
Capacity Trading Platform (CTP)	Fixed Fee - one licence per annum (commodity & capacity)	12,000	12,000
	Fixed Fee - one licence per annum (capacity only)	7,000	7,000
	Variable transaction fee		
	• Daily product fee ($/GJ)	0.044	0.045
	• Weekly product fee ($/GJ)	0.034	0.035
	• Monthly product fee ($/GJ)	0.024	0.025
	Initial Registration Fee - Facility Operators ($ per participant)	15,000	15,450

Note: the variable transaction fees for CTP are including a fee of $0.00309 relating to OTS code panel.

1.12 Day Ahead Auction (DAA)

Purpose of this function	**To reallocate contracted but unnominated transportation capacity to shippers that value it the most** **The following broad services are provided:** • **Auction platform to allocate capacity to shippers** • **Settlement and prudential management of auction transactions** • **Provide auction results to facility operators to facilitate the delivery of auction transactions** • **Update DWGM accreditations in accordance with transactions to a DWGM interface point**
Fees	There is minimal change proposed to the fees for 2020-21.

Table 22 Projected DAA fees

Fee	Fee type	Actual 2019-20	Budget 2020-21
Day ahead Auction (DAA)	Variable fee ($/GJ)	0.034	0.035 +3%
	Initial Registration Fee - Auction participants ($ per participant)	15,000	15,450

Note: the variable fee for DAA is including a fee of $0.00309 relating to OTS code panel.

1.13 Operational Transportation Service (OTS) Code Panel

Purpose of this function	**To assess and consult on proposals to amend the Operational Transportation Service Code and develop proposals to amend the Code, prepare impact and implementation reports on proposals, make recommendations in relation to proposals, report to the AER on proposals, develop proposals at the request of the AER and other related functions**
Fees	OTS code panel fee of $0.00309 per GJ is levied on all CTP and DAA trades.
Other notes	AEMO is permitted to recover costs incurred in relation to the OTS Code Panel including establishing and operating the OTS Code Panel, the participation of the AEMO member of the OTS Code Panel and providing services to facilitate the functioning of the OTS Code Panel.

Table 23 Projected OTS Code Panel fees

Fee	Fee type	Actual 2019-20	Budget 2020-21
OTS Code Panel ($/GJ)	Variable fee ($/GJ)	0.00300	0.00309 +3%

1.14 Gas Bulletin Board (GBB)

Purpose of this function	**To provide information relating to gas production, transmission, storage and usage for facilities that are connected to the east coast gas market** **GBB provides market participants timely data to assist in decision making. This includes capacity outlooks, nominations and forecasts, actual flows, linepack adequacy and additional information for maintenance planning**
Fees	The proposed fee is $0.00048/GJ for Producers and $0.00244/GJ for Participants in Wholesale Gas Markets. These fees are proposed to decrease by 12% and 9% in 2020-21 as a result of lower costs to provide the service.

Table 24 Projected GBB fees

Fee	Actual 2019-20	Budget 2020-21
Producer ($/GJ)	0.00054	0.00048 -12%
Participants in Wholesale Gas Market ($/GJ)	0.00268	0.00244 -9%

1.15 Western Australian Gas Services Information (GSI)

Purpose of this function	**To ensure:** • **Security, reliability and availability of the supply of natural gas** • **Efficient operation and use of natural gas services** • **Efficient investment in natural gas services** • **Facilitation of competition in the use of natural gas services** **The GSI function includes the GBB [WA] and WA GSOO:** • **Similar to the GBB on the East Coast, the WA GBB is an information website hub to provide flow information on gas, transmission, storage, emergency management with supply disruptions, and demand in WA** • **The WA GSOO is an annual planning document providing medium to long-term outlook of WA gas supply and demand and transmission and storage capacity**
Fees	The current GSI recovery is $1.708m. The recovery is proposed to reduce to $1.185 in 2020-21, as a result of lower costs to perform the function.
Other notes	The current three-year ERA determination on AEMO's allowable revenue and capital expenditure covers the period from 1 July 2019 to 30 June 2021.

Table 25 Projected GSI fees

Revenue requirement	Actual 2019-20	Budget 2020-21
AEMO GSI revenue requirement ($'000)	1,708	1,185

1.16 Other budgeted revenue requirements

AEMO also collects revenue to recover the costs of the following functions. The SA planning function costs have remained stable while the settlement residue aution revenuw requirements have reduced.

Table 26 Other revenue requirements

Other revenue requirement	Actual 2019-20	Budget 2020-21
SA Planning ($'000)	1,000	1,000
Settlement Residue Auctions ($'000)	718	626

1.17 Energy Consumers Australia (ECA)

Purpose of this function	To promote the long-term interests of energy customers, residential and small business customers
Fees	AEMO is required to recover the funding for the ECA from market participants (i.e. pass through recovery). Total expenditure budgeted by the ECA to be recovered in 2020-21 is $7.9m (2019-20: $7.6m). The electricity ECA fee is $0.01117 per connection point per week in 2020-21 (3% increase) to reflect the increase in the ECA budgeted revenue requirement. The gas ECA fee is $0.04070 per customer supply point per month in 2020-21 (14% increase) mainly due to an under-recovery in 2018-19 that was not fully accounted for in the 2019-20 fee.

Table 27 ECA requirements

AEMO's ECA Fees	Actual 2019-20	Budget 2020-21
Electricity ($/connection point for small customers per week)	0.01082 +10%	0.01117 +3%
Gas ($/customer supply point per month)	0.03556 +0%	0.04070 +14%

2. Financials

2.1 Draft consolidated profit and loss 2020-21

Table 28 Draft consolidated profit and loss 2020-21

	AEMO (excl. Vic TNSP)			Victorian TNSP			AEMO			Note
	Budget 2019-20 $'000	Budget 2020-21 $'000	Variance $'000	Budget 2019-20 $'000	Budget 2020-21 $'000	Variance $'000	Budget 2019-20 $'000	Budget 2020-21 $'000	Variance $'000	
REVENUE										
Fees and Tariffs	186,896	208,132	21,237	-	-	-	186,896	208,132	21,237	A
TUoS Income	-	-	-	549,555	591,499	41,944	549,555	591,499	41,944	B
PCF Fees	1,000	1,000	-	-	-	-	1,000	1,000	-	
Settlement Residue	-	-	-	63,000	52,017	(10,983)	63,000	52,017	(10,983)	C
Other Revenue	10,461	13,421	2,960	59,884	60,662	778	70,345	74,083	3,738	D
TOTAL REVENUE	**198,357**	**222,553**	**24,196**	**672,439**	**704,178**	**31,739**	**870,796**	**926,731**	**55,935**	
NETWORK CHARGES	-	-	-	(653,394)	(669,893)	(16,499)	(653,394)	(669,893)	(16,499)	E
NET REVENUE	**198,357**	**222,553**	**24,196**	**19,045**	**34,284**	**15,240**	**217,402**	**256,838**	**39,436**	
OPERATING EXPENDITURE										
Total Labour	174,372	203,044	28,672	9,480	10,249	769	183,852	213,293	29,441	
Contractors	1,508	2,817	1,309	260	244	(16)	1,768	3,061	1,293	F
Capitalised internal labour	(44,273)	(50,991)	(6,718)	(115)	(96)	18	(44,388)	(51,087)	(6,700)	
Consulting	19,846	11,601	(8,245)	4,578	11,641	7,063	24,423	23,241	(1,182)	G
Fees-Agency, Licence and Audit	2,166	2,133	(33)	-	-	-	2,166	2,133	(33)	
Information Technology and Telecommunication	31,333	33,212	1,879	188	16	(172)	31,522	33,228	1,706	H
Occupancy	7,467	8,274	807	-	-	-	7,467	8,274	807	I
Training & Recruitment	4,019	4,785	766	64	102	38	4,082	4,886	804	J
Travel & Accommodation	3,424	2,436	(988)	78	87	9	3,502	2,523	(980)	
Other Expenses from Ordinary Activities	8,418	8,839	421	11	38	27	8,429	8,877	448	K
Depreciation and Amortisation	31,017	28,445	(2,573)	9	12	3	31,026	28,457	(2,569)	L
Financing Costs	869	1,393	524	-	-	-	869	1,393	524	M
OPERATING EXPENDITURE (excluding external recoverable costs)	**240,166**	**255,986**	**15,820**	**14,553**	**22,292**	**7,739**	**254,719**	**278,279**	**23,560**	
External Recoverable Consultancy	1,367	1,834	467	1,821	1,177	(644)	3,188	3,011	(177)	
Corporate Recovery	(5,887)	(7,553)	(1,667)	5,887	7,553	1,667	-	0	0	
TOTAL OPERATING EXPENDITURE	**235,646**	**250,267**	**14,621**	**22,261**	**31,023**	**8,762**	**257,907**	**281,290**	**23,383**	
ANNUAL SURPLUS / (DEFICIT)	**(37,289)**	**(27,714)**	**9,576**	**(3,216)**	**3,262**	**6,478**	**(40,505)**	**(24,452)**	**16,053**	
Transfer to Reserves	(1,387)	(1,387)	0	-	-	-	(1,387)	(1,387)	0	
Brought Forward Surplus	(3,329)	(38,021)	(34,692)	3,085	(4,124)	(7,209)	(244)	(42,145)	(41,901)	
ACCUMULATED SURPLUS / (DEFICIT)	**(42,005)**	**(67,122)**	**(25,116)**	**(130)**	**(862)**	**(731)**	**(42,136)**	**(67,984)**	**(25,848)**	

Notes to consolidated profit and loss 2020-21

Revenue

A Higher fees and tariffs mostly due to additional revenue in the NEM reflecting the 12% uplift in fees. National Transmission Planner (NTP) revenues are also budgeted to materially increase given the broadening of AEMO's role.

B & E TUOS income and Network Charges. Refer to comments in *Section 1.4 Victorian Electricity Transmission Network Service Provider (TNSP)*.

C Decrease in settlement residue estimated in the Victorian region due to lower estimated spot prices, partly offset by higher estimated Settlement Residue Auction proceeds.

D Higher other revenue due to an increase in pass-through costs in the Victorian TNSP function and higher connection revenue.

Expenditure

F Labour uplift reflects a combination of additional resources required to manage:

- The ISP – uplifting the ISP to be an actionable energy roadmap that will replace the initial stages of the Regulatory Investment Test – Transmission (RIT-T), providing a ready-made modelling suite with assumptions, transparent justifications for actionable projects, and, most importantly, greater certainty of project success once a project has been declared actionable.
- The VNI West (RIT-T) project that is being jointly run by AEMO and TransGrid to assess the viability of increasing interconnector capacity between Victoria and New South Wales.
- Additional resources to increase system strength assessments, build capacity to review NEM incidents, support the commissioning of new interconnectors, and increase the analysis and reporting of marginal loss factors (MLFs).
- An uplift in stakeholder engagement across all of the large programs and activities being undertaken across the organisation.

G Consulting costs are broadly in line with an uplift in specialist advice and support regarding increased activities to manage the ISP and RIT-T activities, partly offset by broader consultancy reductions across the organisation.

H IT and Telecommunications costs reflects increased emphasis on national forecasting and modelling utilising cloud technologies, new distributed energy resources (DER) market applications, and critical multi-vendor weather support for grid operations.

I Marginally higher occupancy costs mostly reflect additional resources.

J Higher training and recruitment costs in line with additional resource requirements.

K Lower travel and accommodation costs reflecting COVID-19 impacts.

L Other expenses from ordinary activities are higher, mostly due to a material uplift in annual insurance premiums.

M Depreciation and amortisation is lower than 2019-20, due to a reassessment of the useful lives of some projects.

N Higher financing costs reflect an increase in the debt facility.

Note: financing costs relating to capex projects will initially be capitalised and recovered through fees following project completion.

3. Capital expenditure program

Table 29 Capital spend – next three years

Capital Expenditure ($'m)	2019-20 and prior	Budget 2020-21	Estimate 2021-22	Estimate 2022-23
Digital Platform, System and Cyber Refresh and ongoing maintenance	104.6	87.4	73.3	83.0
DER Integration – Net of estimated Govt funding	21.6	20.4	(2.3)	1.4
Regulatory Compliance Programs	43.2	56.2	25.0	18.4
Net Capital Expenditure	169.4	164.0	96.0	102.8

The above table:

- Provides an estimate of AEMO's capital program over the following three years.
- Does not include any allowance to fund transformational market initiatives that are as yet unconfirmed but may materialise; for example, the implementation of the Consumer Data Rights program or the implementation of an ahead market and a two-sided market.

AEMO's capital spend is largely driven by the significant change the industry is going through, which has resulted in a need to refresh current systems and carry out large regulatory-directed programs.

AEMO is required to initially fund the build of these programs via an external debt facility and will commence depreciating these assets, including interest costs, (and recovering these costs from participants) once the programs are completed in forward years.

This results in AEMO being required to take out a large funding facility (currently $500m).

The current capital program represents AEMO's current plans, however:

- An internal review of the capital program is currently being conducted.
- AEMO is working with stakeholders and other regulatory bodies to assess the impact of COVID-19 on the industry reform initiatives.
- AEMO has engaged an external party to conduct a thorough review of the capital program and advise, where practical, if cost and risk can be reduced.

AEMO's capital program can be broadly grouped into three categories:

- **Digital Platform, System and Cyber Refresh and ongoing maintenance**.
  - A high proportion of AEMO's systems are bespoke and are nearing end of life and need to be replaced. AEMO is planning a significant refresh of its systems over the coming years that will include the development of a modern digital platform that will provide more reliable and transparent data.
  - The 'do nothing' option would result in continued higher costs to run, modify and operate AEMO's systems, due to age, complexity and capability.
  - The significant increase in data volumes necessitates an increase in computational capability, analytics, design, and digitalisation to support the real-time operation of AEMO's energy systems and markets.
  - The systems refresh focus areas over the next 12 months will include:

  - Providing more granular and timely data to stakeholders.
  - Refreshing forecasting systems to absorb new data sets, fine tune algorithm accuracy and improve scalability and timeliness.
  - Uplifting capability across cyber and data control to detect and prevent attack and control data leakage.
  - Improving industry preparedness to detect and coordinate response to cyber-attacks.
- **DER Integration.**
  - AEMO is working in partnership with the ESB, market bodies, and stakeholders to design and implement technical integration of DER. AEMO is seeking government funding to minimise the impact on participant fees for these programs.
- **Regulatory Compliance Programs.**
  - 5MS – the program to move from a 30-minute settlement period to a 5-minute settlement period was initially planned to go live on 1 July 2021. Industry is currently assessing the benefits of a deferral of this go-live date. AEMO is currently continuing work on this program in line with the original date in the AEMC's Rule determination.
  - WA Market Reform – AEMO continues to support the WA Government's Foundational Regulatory Frameworks including the planning and implementation of a new market design.
  - Wholesale Demand Response – this program will implement a mechanism for third party demand response service providers to participate in the wholesale energy market.

Appendix A. Fee schedules

A1.1 Fee schedule of electricity functions

Table 30 Budgeted total revenue requirement by function

Function	Budget 2020-21 $'000	Rate	Paying Participants
NEM			
General Fees (unallocated)	29,273	$0.16780/MWh of customer load	Market Customers
Allocated Fees			
Market Customers	36,884	$0.21140/MWh of customer load	Market Customers
Generators * and Market Network Service Providers	31,419	Daily rate calculated on 2019 capacity/energy basis	Generators and Market Network Service Providers
NEM Revenue Requirement	**97,575**		
Participant Compensation Fund	1,000	Daily rate calculated on capacity/ energy basis	Scheduled Generators, Semi-Scheduled Generators and Scheduled Network Service Providers
Registration fees	3,602		Intending Participants
Other	9,071		Dependent on service provided
Project developer		$6,180 per assessment per facility	Project developers
NEMDE queue		$15,00 per application	Registered participants
TOTAL NEM	**111,248**		
FRC ELECTRICITY			
FRC operations	13,780	$0.02550 per connection point per week	Market Customers with a Retail Licence
Other	2	$850 per book build application	Voluntary Book Build Participant Accreditation Fee
TOTAL FRC ELECTRICITY	**13,782**		
National Transmission Planner	20,100		Transmission Network Service Providers
Energy Consumers Australia	5,976	$0.01117/connection point for small customers/week	Market Customers
Additional Participant ID		$5,500 per additional participant ID	Existing Participants
WA WHOLESALE ELECTRICITY MARKET			
WEM Market Operator fee	13,549	$0.387/MWh	Market Customers and Generators
WEM System Management fee	18,153	$0.519/MWh	Market Customers and Generators
WA WEM Revenue Requirement	**31,702**		

* Excluding non-market non-scheduled generators

Table 31 Fee schedule of new NEM registrations

Application type	2020-21 $
Registration as Scheduled Market Generator [A]	23,690
Registration as Semi-Scheduled Market Generator	31,930
Registration as Scheduled Non-Market Generator	17,510
Registration as Semi-Scheduled Non-Market Generator	26,780
Registration as Non-Scheduled Market Generator	20,600
Registration as Non-Scheduled Non-Market Generator	14,420
Registration as Market Customer	11,330
Registration as Market Small Generation Aggregator	11,330
Transfer of Registration	11,330
Registration as Metering Co-ordinator (MC) [B]	11,330
Registration as Market Ancillary Service Provider	16,480
Registration as Network Service Provider	10,300
Registration as Trader	14,420
Registration as Reallocator	13,390
Classification of generating units as frequency control ancillary services (FCAS) generating units [B]	10,300
Classification of load as frequency control ancillary services load – new ancillary services or classify load in a new region [C]	10,300
Classification of a Dedicated Connection Asset	5,150
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	2,060
Registration as an Intending Participant	6,180
Exemption from registration	6,180
Disbursement Charge – Additional Energy Conversion Model – Semi Scheduled Market Generator	5,150
Disbursement Charge – Additional Energy Conversion Model – Non-Scheduled Market Generator	2,575

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.

Table 32 Fee schedule of new WA WEM registrations

Application type	2020-21 $
Rule Participant Registration Application Fee	1,900
Facility Registration Application Fee	3,800
Facility Transfer Application Fee	1,900
Conditional Certification of Reserved Capacity	1,164
Resubmission - Application for Early Certified Reserved Capacity	10,671
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)	515

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

Table 33 Fee schedule of new Power of Choice accreditations

Application type	2020-21 $
Initial Deposit – Embedded Network Manager	2,000
Initial Deposit – Metering Data Providers	5,000
Initial Deposit – Metering Providers	5,000
Incremental charge rate per hour	TBA

A1.2 Fee schedule of gas functions

Table 34 Gas fee by function

Function	Rate 2020-21	Basis
Vic Declared Wholesale Gas Market		
Energy Tariff	0.08887	$/GJ withdrawn
Distribution Meter	1.2858	$/day per meter
PCF	Nil	$/GJ withdrawn
VIC Gas FRC	0.06221	$ per customer supply point/ mth
QLD Gas FRC	0.26441	$ per customer supply point/ mth
SA Gas FRC	0.20214	$ per customer supply point/ mth
NSW/ ACT Gas FRC	0.14040	$ per customer supply point/ mth
WA Gas FRC	0.12170	$ per customer supply point/ mth
Annual fee – members	20,649	per annum
Annual fee – associate members*	4,027	per annum
STTM		

Function	Rate 2020-21	Basis
Activity Fee	0.03684	$/GJ withdrawn
PCF Fee – Syd	Nil	$/GJ withdrawn per hub per ABN
PCF Fee – Adel	Nil	$/GJ withdrawn per hub per ABN
PCF Fee – Bris	Nil	$/GJ withdrawn per hub per ABN
Energy Consumers Australia	0.04070	$ per customer supply point/ wk
Gas Statement of Opportunities	0.03869	$ per customer supply point/ mth
Gas Supply Hub		
Fixed Fee – Trading Participants	12,000	$ per licence per annum
Fixed Fee – Trading Participants	12,000	$ per additional licence per annum
Fixed Fee – Reallocation participants	9,000	$ per licence per annum
Fixed Fee – - Viewing participants	3,600	$ per licence per annum
Variable Fee – Daily product fee	0.03	$/GJ
Variable Fee – Weekly product fee	0.02	$/GJ
Variable Fee – Monthly product fee	0.01	$/GJ
Gas Trading Platform		
Fixed Fee – commodity and capacity	12,000	$ per licence per annum
Fixed Fee – capacity only	7,000	$ per licence per annum
Variable Fee – Daily product fee	0.045	$/GJ
Variable Fee – Weekly product fee	0.035	$/GJ
Variable Fee – Monthly product fee	0.025	$/GJ
Day Ahead Auction	0.035	$/GJ
Gas Bulletin Board		
Producers	0.00048	$/GJ withdrawn
Wholesale market participants	0.00244	$/GJ withdrawn
WA Gas Services Information	1,557	$'000
Additional Participant ID	$5,500	$ per additional participant ID

Table 35 Fee schedule of new gas registrations

Market	Budget 2020-21	Basis
Victoria FRC Gas	19,570	$ per participant
QLD FRC Gas	17,510	$ per participant
SA FRC Gas	16,480	$ per participant
NSW FRC Gas	N/A	N/A
WA FRC Gas	13,435	$ per member
WA FRC Gas	2,686	$ per associate member
Victoria Wholesale Gas	N/A	N/A
STTM	N/A	N/A
Capacity Trading Reform/ Day ahead auction – part 24 Facility Operator	15,450	$ per facility operator
Day ahead auction – Auction Participant	15,450	$ per participant
BB allocation agents	15,450	$ per participant
BB transportation facility user	11,330	$ per participant
BB capacity transaction reporting agents	11,330	$ per participant

Symbols and abbreviations

Term	Definition
5MS	5 Minutes Settlement
CTP	Capacity Trading Platform
DAA	Day Ahead Auction
DER	Distributed Energy Resource
DWGM	Declared Wholesale Gas Market
ERA	Economic Regulation Authority
ESOO	Electricity Statement of Opportunities
FRC	Full Retail Contestability
GBB	Gas Bulletin Board
GJ	Gigajoule
GSOO	Gas Statement of Opportunities
TJ	Terajoule
TNSP	Transmission Network Services Provider