2017–18 CONSOLIDATED FINAL BUDGET AND FEES

AUSTRALIAN ENERGY MARKET OPERATOR

Published: **May 2017**

EXECUTIVE SUMMARY

The 2017-18 final budget provides a consolidated view of AEMO's 2017-18 revenue and expenses, fees for 2017-18 and estimates for the following four year period.

AEMO continues its commitment to apply commercial discipline to control total operating costs and where possible, to reduce the impact of fee increases to market participants.

AEMO's 2017-18 final budgeted expenditure is $181.5M, an increase of 2.4% ($4.2M) on the 2016-17 budget.

Table 1 provides a comparison of the 2017-18 budget with the prior year.

Table 1 — AEMO budget comparison to the prior year

Budget year	2016-17 Budget	2017-18 Budget	Variance
Revenue	$178.5M	$174.6M	($3.9M)
Expenditure	$177.3M	$181.5M	($4.2M)
Surplus/(Deficit)	$1.2M	($6.9M)	($8.1M)

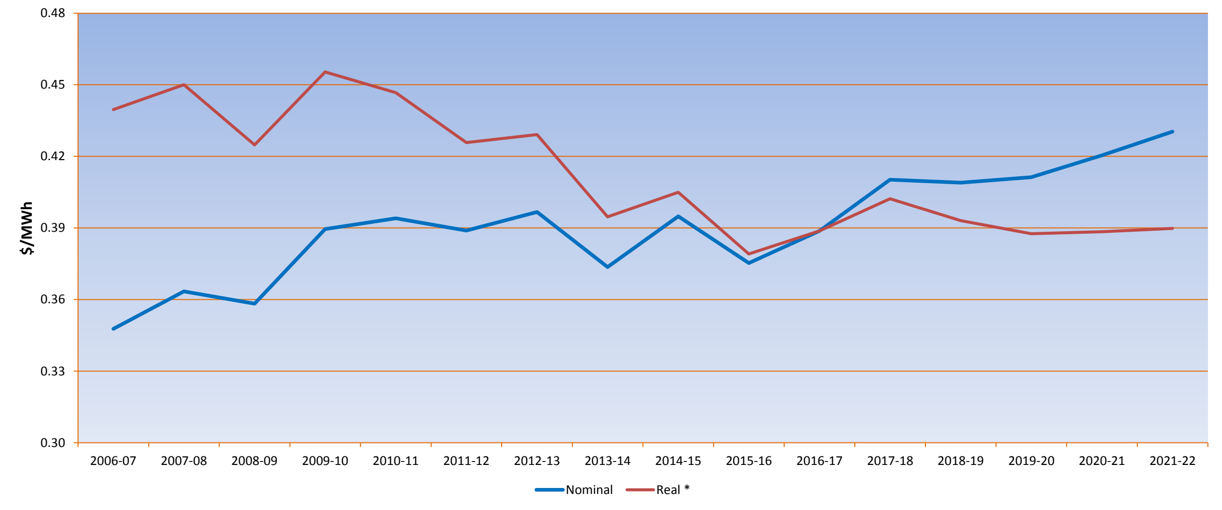
The majority of the 2017-18 fees are lower than the current fees, however the fee for the largest function, the NEM will increase.

As shown in Figure 1 below, in real terms after adjusting for inflation, the NEM fee has been trending downwards since the commencement of AEMO in 2009, however the fee will increase by 6% in 2017-18.

The key reasons for the increase in the NEM fee are:

- Increased resources focused on security of the system, particularly following the recent events in South Australia.
- Increased investment in the forecasting and planning approach with an objective of reducing manual processes and providing stakeholders with greater insights and more accessible information that is provided on a more regular basis.
- Increased investment in core IT infrastructure and systems, such as the upgrade to our Energy Management System and Oracle platform, to ensure these systems remain current and supported and, where appropriate, are consolidated to reduce future maintenance costs.

Figure 1 – NEM projected fees



AEMO's project budget in 2017-18 is $28.3M, which is $2.9M lower than the 2016-17 budget.

The key areas of investment are:

- Power of Choice – this program is to design and implement changes to electricity and retail market arrangements and associated infrastructure, in line with the Australian Energy Market Commission's (AEMC) Power of Choice review.
- Increased IT investment to ensure systems are fit for purpose and supported along with initiatives that require initial investment to consolidate systems and services that will reduce future maintenance costs.
- WA Market reform – the budget for the reform program has been reduced to reflect an approach of focussing on critical activities only until future clarity on the reform program is provided by the WA Government.

2017-18 Fees

Table 2 — Key fees

Function	Budget 2017-18	Current 2016-17	Change	Prior year published estimate 2017-18	Unit
Electricity					
NEM	0.41	0.39	↑ 6%	0.40	$/MWh
FRC - Electricity	0.075	0.061	↑ 23%	0.065	$/MWh
National Transmission Planner	0.02126	0.01606	↑ 32%	0.02114	$/MWh
VIC TNSP - TUOS Fees	474,580	496,548	↓ -4%	512,385	$'000
Total WEM Fee	**0.791**	**0.876**	↓ **-10%**	**N/A**	**$/MWh**
WA WEM - Market Operator	0.357	0.504	↓ -29%	0.442	$/MWh
WA WEM - System Management	0.434	0.372	↑ 17%	N/A	$/MWh
Gas					
DWGM - Energy Tariff	0.08544	0.0863	↓ -1%	0.08457	$/GJ withdrawn
STTM - Activity Fee	0.06884	0.07939	↓ -13%	0.07708	$/GJ withdrawn
VIC FRC Gas	0.08305	0.09771	↓ -15%	0.08305	$ per customer supply point per month
QLD FRC Gas	0.22256	0.26184	↓ -15%	0.22256	$ per customer supply point per month
SA FRC Gas	0.22615	0.25994	↓ -13%	0.23135	$ per customer supply point per month
NSW & ACT FRC Gas	0.16918	0.16750	↑ 1%	0.17039	$ per customer supply point per month
WA FRC Gas	0.13485	0.30815	↓ -56%		$ per customer supply point per month
Gas Statement of Opportunities	0.03518	0.03198	↑ 10%	0.03614	$ per customer supply point per month
Gas Supply Hub - daily	0.03	0.03	↔ 0%	0.03	$/GJ
Gas Supply Hub - weekly	0.02	0.02	↔ 0%	0.02	$/GJ
Gas Supply Hub - monthly	0.01	0.01	↔ 0%	0.01	$/GJ
Gas Bulletin Board	1,429	1,646	↓ -13%	1,383	$'000
Gas Services Information	1,527	1,834	↓ -17%	2,454	$'000
Other					
SA Planning	1,000	1,000	↔ 0%		$'000
Settlement Residue Auctions	295	291	↑ 1%		$'000

Fees collected on behalf of Energy Consumers Australia (ECA)					
ECA (Electricity)	0.00979	0.00951	↑ 3%		$ per connection point for small customer per week
ECA (Gas)	0.03199	0.03183	↑ 1%		$ per customer supply point per month

N/A – The System management function was transferred from Western Power to AEMO on 1 July 2016.

2017-18 expenditure by category

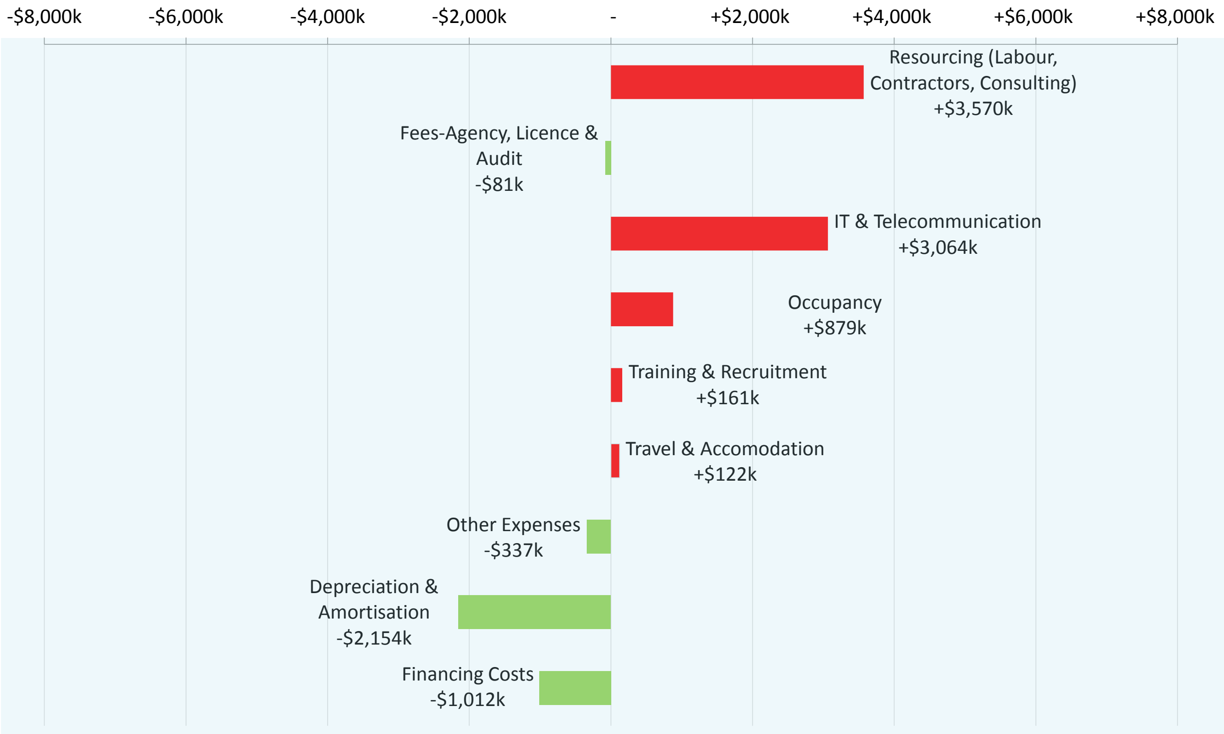
AEMO functions

The total expenditure budget for AEMO functions in 2017-18 is $181.5M which is $4.2M (2.4%) higher than the 2016-17 budget.

Further information on the expenditure variances is provided in Section 2.3.

Figure 2 provides a comparison, by expenditure category of AEMO's 2017-18 budget to the 2016-17 budget.

Figure 2 – Comparison of expenditure by category



Energy consumption

National Electricity Market (NEM)

The budgeted consumption for 2017-18 is based on available data estimates used in the 2016 National Electricity Forecast Report (NEFR) with updates for key expected changes.

The 2017-18 consumption is expected to increase slightly and the future year's consumption is expected to be flat as the decrease in consumption due to solar PV uptake and energy efficiency is offset by population growth. The industrial consumption is also expected to be flat.

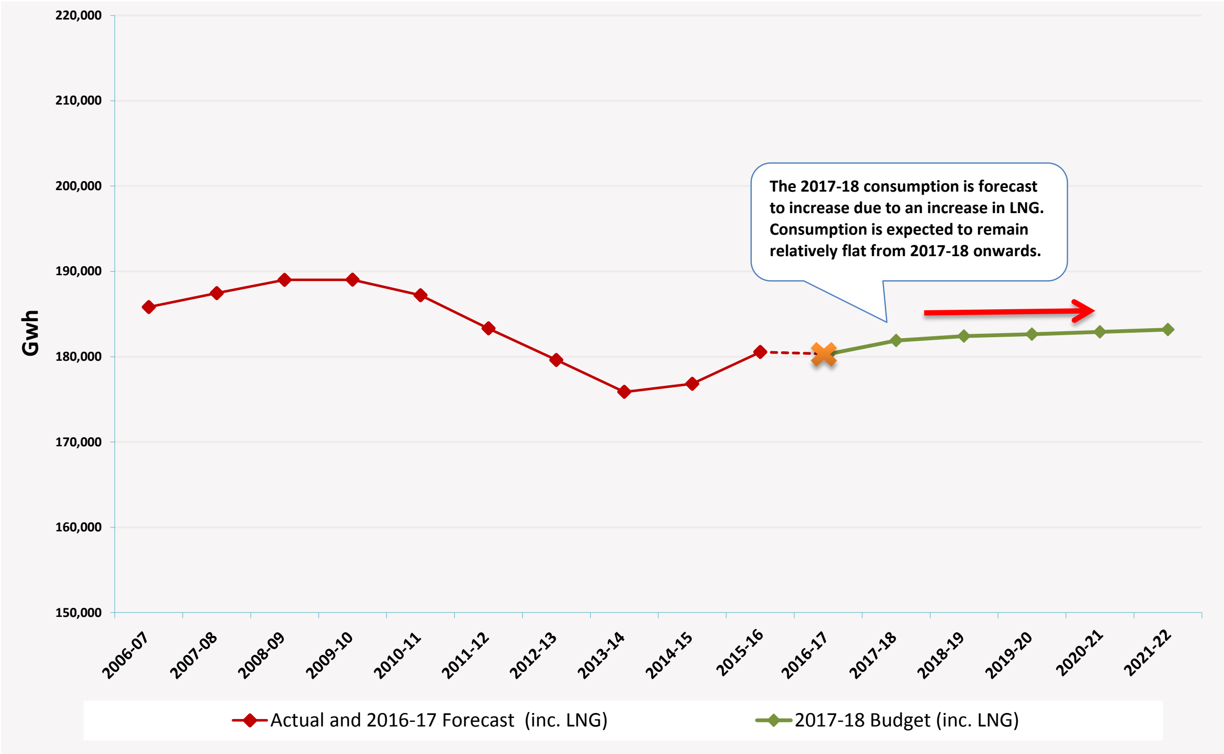
Table 3 — NEM consumption

GWh	Budget 2016-17	Forecast [1] 2016-17	Budget 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21	Estimate 2021-22
NEM	179,893	180,311	181,895	182,417	182,645	182,913	183,186
			+1.1%	+0.3%	+0.1%	+0.1%	+0.1%

[1] Forecast annual 2016-17 consumption as at March 2017

Figure 3 below demonstrates the forecasted consumption used to calculate the NEM fee.

Figure 3 – Annual electricity consumption (market customer load)



Victorian Declared Wholesale Gas Market (DWGM)

The final budgeted 2017-18 consumption is based on the National Gas Forecasting Report (NGFR) published in December 2016.

AEMO estimates an overall increase of 5.2% in 2017-18 consumption from the 2016-17 budget. This is due to increases in Victorian exports to NSW, and increased domestic consumption, partially offset by decreases in industrial consumption. Overall consumption is forecast to fall from 2018-19 due to reduction in domestic, industrial and GPG consumption. Industrial consumption is estimated to decline from 2017-18.

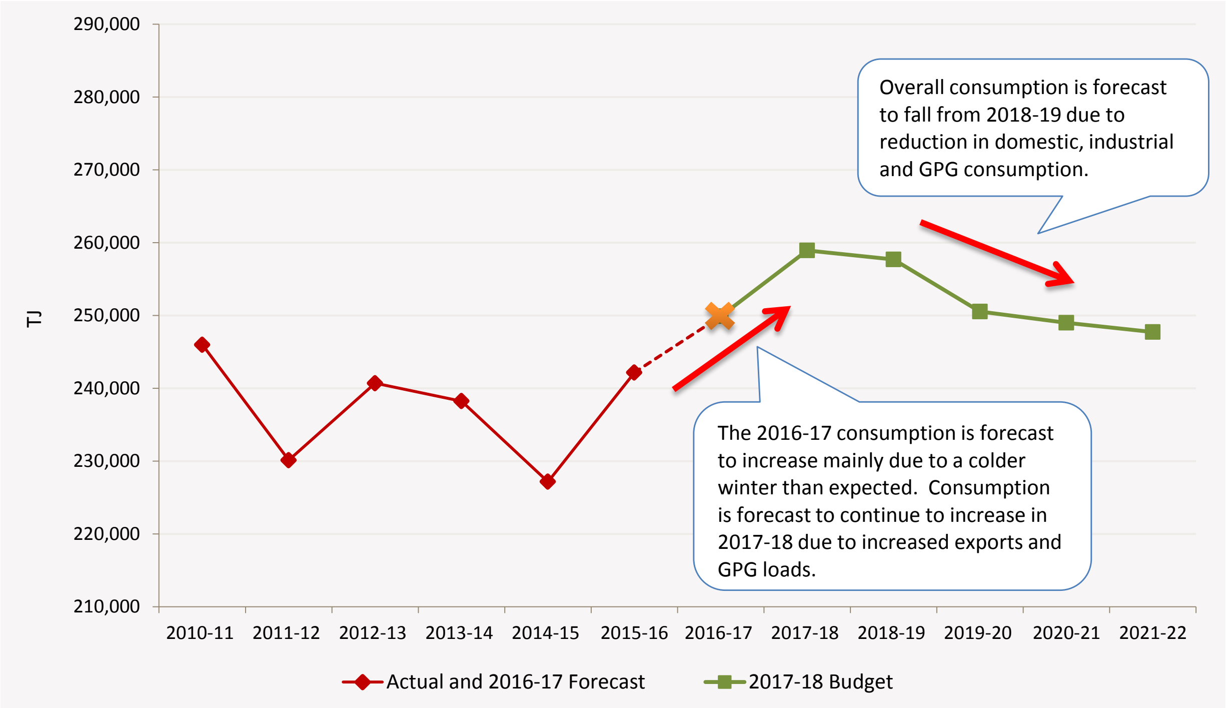
Table 4 — DWGM consumption

TJs	Budget 2016-17	Forecast [1] 2016-17	Budget 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21	Estimate 2021-22
Domestic	125,822	131,173	127,045	126,348	125,507	124,190	122,678
Industrial	72,144	70,514	68,355	67,286	65,781	65,192	65,004
Export	45,664	45,687	58,660	59,000	59,000	59,000	59,000
GPG	2,500	2,515	4,857	5,058	261	626	1,042
TOTAL	**246,130**	**249,890**	**258,917**	**257,691**	**250,550**	**249,009**	**247,723**
			+5.2%	-0.5%	-2.8%	-0.6%	-0.5%

[1] Forecast annual 2016-17 consumption as at January 2017

Figure 4 below demonstrates the impact of increasing consumption on the DWGM fee.

Figure 4 – Annual DWGM consumption



Short Term Trading Market (STTM)

Consumption in the STTM is expected to increase slightly in 2017-18 and then decline over the next two years.

This is mainly driven by the Brisbane hub, with planned closures of large industrial companies and lower Gas Power Generation.

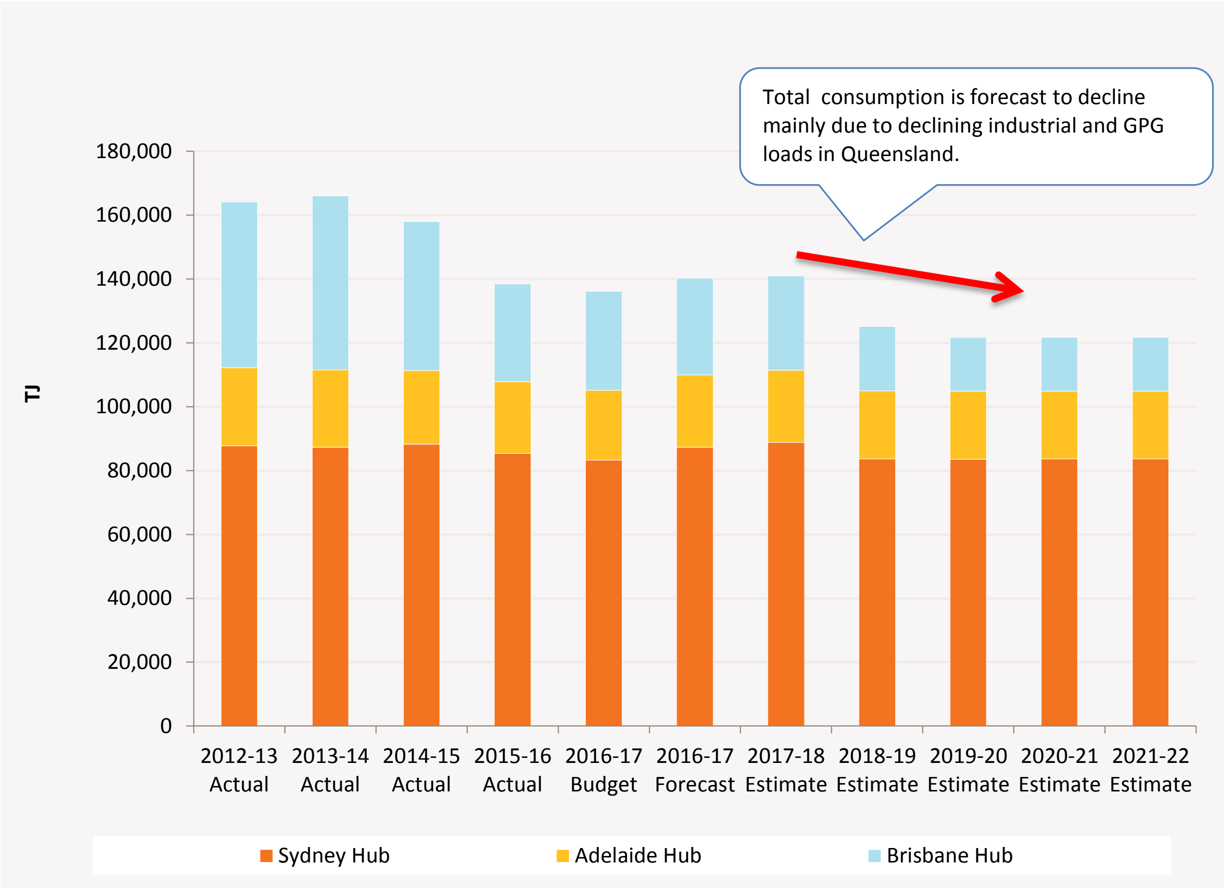
Table 5 — STTM consumption

TJs	Budget 2016-17	Forecast [1] 2016-17	Budget 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21	Estimate 2021-22
Adelaide	21,835	22,683	22,576	21,317	21,294	21,291	21,291
Brisbane	31,062	30,287	29,584	20,212	16,810	16,808	16,808
Sydney	83,304	87,313	88,842	83,659	83,588	83,635	83,635
TOTAL	**136,201**	**140,283**	**141,002**	**125,188**	**121,692**	**121,734**	**121,734**
			3.5%	-11.2%	-2.8%	+0.0%	+0.0%

1 Forecast annual 2016-17 consumption as at March 2017

Figure 5 below demonstrates the declining STTM consumption particularly in the Brisbane hub.

Figure 5 – Annual STTM Gas consumption



WA Wholesale Electricity Market (WEM)

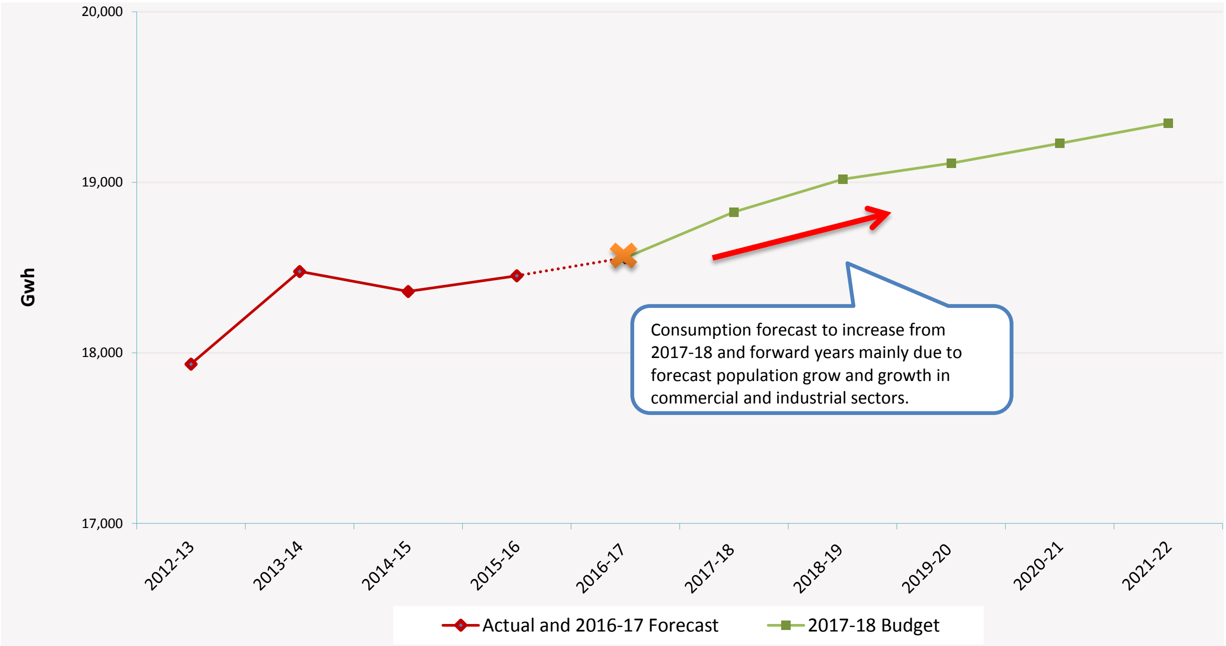
Consumption is expected to increase slightly due to anticipated economic growth of 3.2% and forecast population growth of 1.7% in Western Australia, partially offset by investments in solar PV systems by both residential and non-residential customers.

Table 6 — WEM consumption

GWh	Budget 2016-17	Forecast 2016-17	Budget 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21	Estimate 2021-22
Load forecast	18,558	18,558	18,826	19,019	19,112	19,229	19,348
			+1%	+1%	+0%	+1%	+1%

Figure 6 below demonstrates the forecast increase in consumption for the WEM.

Figure 6 – Annual WEM consumption



CONTENTS

TABLES

FIGURES

CHAPTER 1. FEES AND TARIFFS

1.1 National Electricity Market (NEM)

The benchmark NEM fee will increase 6% from $0.39/MWh to $0.41/MWh in 2017-18. This increase is higher than the estimate of $0.40/MWh provided to stakeholders in the 2016-17 budget.

The key reasons for the increase are:

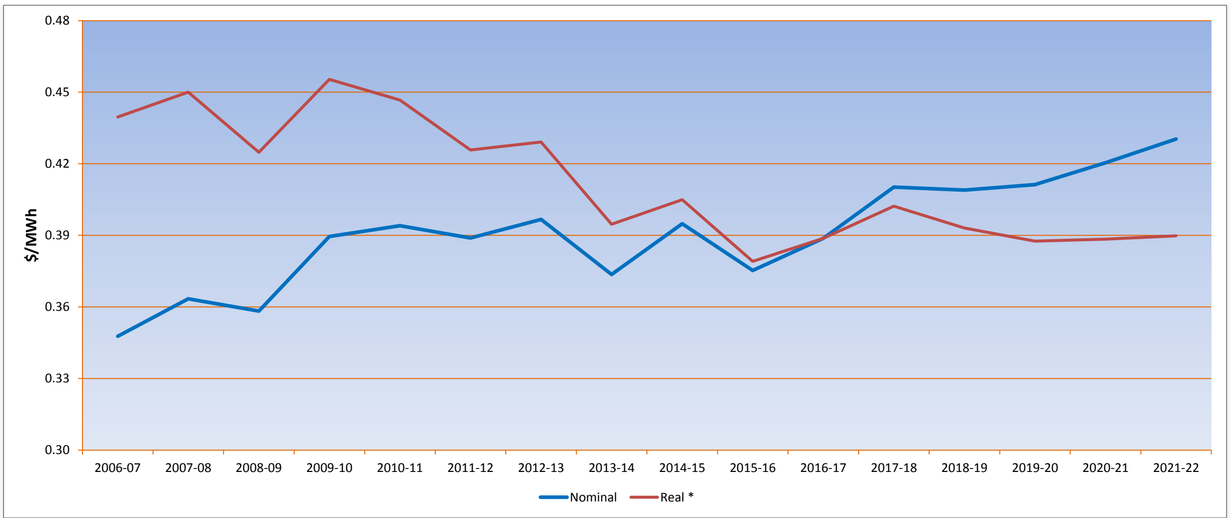
- Increased resources focused on security of the system, particularly following the recent events in South Australia.
- Increased investment in the forecasting and planning approach with an objective of reducing manual processes and providing stakeholders with greater insights and more accessible information that is provided on a more regular basis.
- Increased investment in core IT infrastructure and systems, such as the upgrade to our Energy Management System and Oracle platform, to ensure these systems remain current and supported and, where appropriate, are consolidated to reduce future maintenance costs.

It is anticipated that payments may be made from the Participant Compensation Fund in 2016-17. In line with the National Electricity Rules, a PCF fee will be charged to replenish the fund by $1M in 2017-18. Estimates of future PCF fees are not provided as they are heavily impacted by future claims that may arise from time to time.

Table 7 — NEM projected fees (indicative benchmark)

Fee	Actual 2016-17	Budget 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21	Estimate 2021-22
NEM fee ($/MW·h)	0.39	0.41	0.41	0.41	0.42	0.43
	4%	+6%	-0%	+1%	+2%	+2%
PCF fee ($/MW·h)	0	0.01	TBC	TBC	TBC	TBC

Figure 7 – NEM projected fees



* Real values are the nominal amounts adjusted for inflation. Prices have been calculated relative to the 2016-17 price.

1.2 Full Retail Contestability (FRC) Electricity

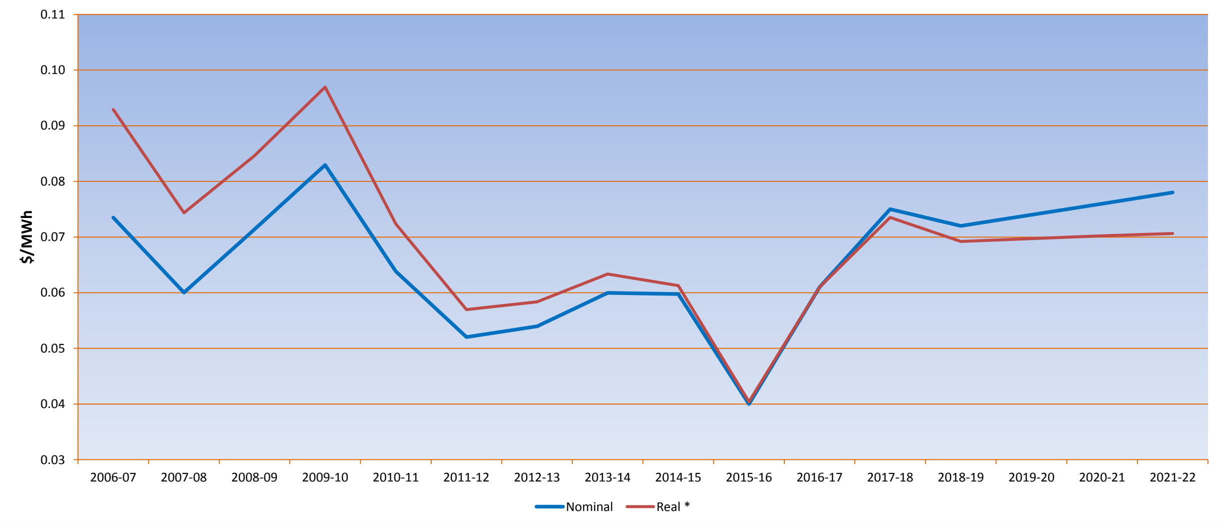
The FRC electricity fee will increase to $0.075/MWh which is 23% higher than the 2016-17 fee of $0.061/MWh, mainly due to work associated with the Power of Choice program that will be completed in December 2017.

It should also be noted that the 2016-17 fee was significantly increased due to a combination of work on the Power of Choice program and the 2015-16 fee being reduced to return a prior year's surplus.

Table 8 — FRC Electricity Projected Fees (Indicative Benchmark)

Fee	Actual 2016-17	Budget 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21	Estimate 2021-22
($/MW·h)	0.061	0.075	0.072	0.074	0.076	0.078
	+53%	+23%	-4%	+3%	+3%	+3%

Figure 8 – FRC electricity projected fees



* Real values are the nominal amounts adjusted for inflation. Prices have been calculated relative to the 2016–17 price.

1.3 National Transmission Planner (NTP)

The NTP fee is budgeted to increase by 32% from $0.01606/MWh to $0.02126/MWh in 2017-18 which is closely aligned to the 2017-18 fee estimated in the 2016-17 budget of $0.02114.

The 2017-18 increase is due to the 2016-17 fee being lowered to return a surplus from prior years.

Table 9 — National Transmission Planner Project Fees

Fee	Actual 2016-17	Budget 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21	Estimate 2021-22
($/MW·h)	0.01606	0.02126	0.02350	0.02409	0.02470	0.02532
	-22%	+32%	+11%	+3%	+3%	+3%

1.4 Victorian Electricity Transmission Network Service Provider (TNSP)

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 2017-18 fees are 4% lower than the 2016-17 fees primarily due to increased inter-regional settlement residue.

Forward year estimates have not been made due to the volatility of the factors listed above.

Table 10 — Projected TUOS Revenue Requirement

Fee	Actual 2016-17 ($'000)	Budget 2017-18 ($'000)	Estimate 2018-19 ($'000)	Estimate 2019-20 ($'000)	Estimate 2020-21 ($'000)
TUOS fees	496,548	474,580	TBC	TBC	TBC
	-3%	-4%			

1.5 WA Wholesale Electricity Market (WEM)

The total WEM fee reduces by 10% in 2017-18 and is comprised of a Market Operator component and a Systems Management component.

The revenue for both the WEM Market Operator function and the System Management function is regulated by the WA Economic Regulation Authority (ERA). The current ERA determination concludes on 30 June 2019 and therefore fees beyond this point have not been estimated.

It should also be noted that the 2016-17 fees for both the Market Operator and System Management functions were retained at the 2015-16 level due to the delay in the regulatory determination of AEMO's allowable revenue as a result of the uncertainty of the impact of the market reform program.

The WEM Market Operator fee reduces $0.15/MWh (29%) in 2017-18 due to lower depreciation from a number of assets being fully depreciated during 2016-17, a reduction in labour expenditure and lower licencing costs for software since joining AEMO. The fee is estimated to decrease by a further 2% in 2018-19.

The System Management fee is expected to increase by 17% in 2017-18 and 16% in 2018-19 as a result of the need to transfer to a stand-alone control room security desk and costs associated with transitioning the Systems Management function out of Western Power.

Table 11 — WA WEM fees

Fee	Actual 2016-17	Budget 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21
WEM Market Operator fee ($/MW·h)	0.504	0.357 -29%	0.350 -2%	TBC	TBC
WEM System Management fee ($/MW·h)	0.372	0.434 +17%	0.505 +16%	TBC	TBC
WEM fee ($/MW·h)	0.876	0.791	0.855	TBC	TBC
		-10%	+8%		
WEM fee (indicative benchmark) [1] ($/MW·h)	1.752	1.583	1.710	TBC	TBC

1The fee of $1.583 $/MWh 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 $0.357/MWh and $0.434/MWh for the Market Operations and System Management functions respectively.

1.6 Declared Wholesale Gas Market (DWGM)

The DWGM energy tariff is budgeted to decrease 1% from $0.08630/GJ to $0.08544/GJ in 2017-18. The 2017-18 fee is slightly higher (1%) than the fee estimated as part of the 2016-17 budget process.

Consumption growth is estimated to increase in 2017-18 due to higher Victorian exports to NSW and higher Gas Powered Generation, offset by a decrease in domestic consumption. Industrial consumption is expected to decline across 2017-18 to 2019-20 and remain flat until 2021-22.

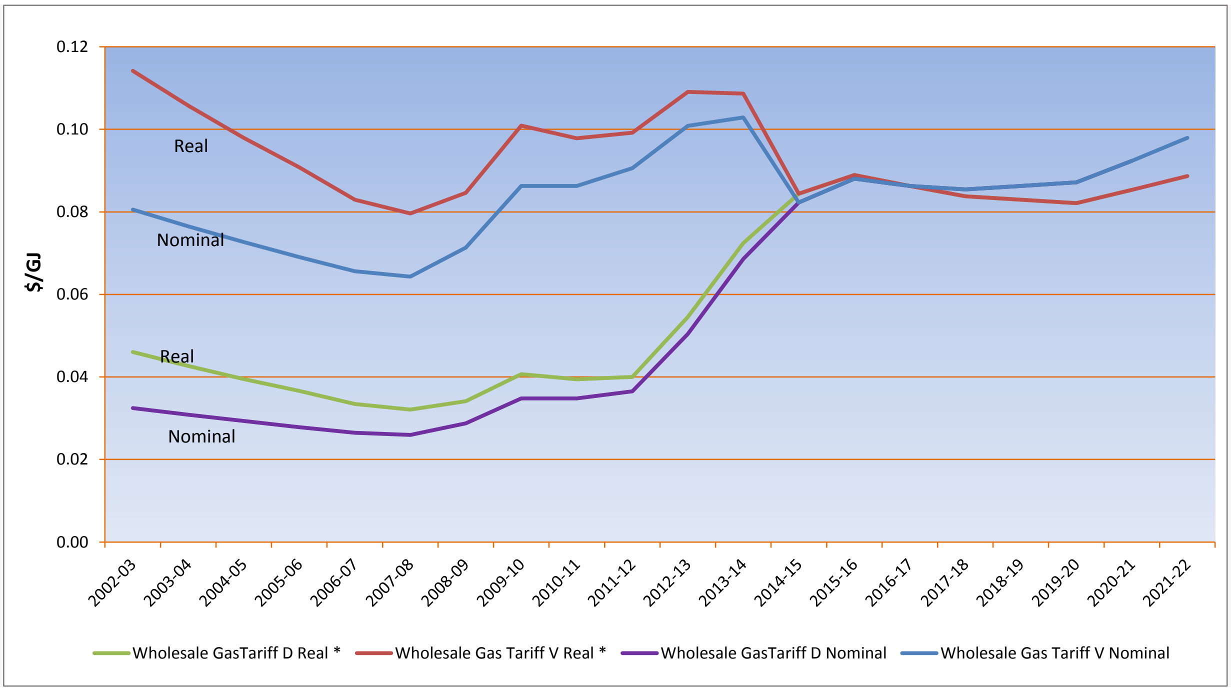
The distribution meter fee for 2017-18 relates to metering data services and is expected to decrease in 2017-18 to return an over recovery of funds. The fee will then return to historical levels in 2018-19.

The Participant Compensation Fund (PCF) fee is not required to be charged in 2017-18 as the current level of DWGM PCF funds being held meets the Rules requirement. Estimates of future PCF fees are not provided as they are mainly impacted by future items that may arise from time to time.

Table 12 — Summary of DWGM Fees

Fee	Actual 2016-17	Budget 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21	Estimate 2021-22
Energy Tariff ($/GJ)	0.08630 -2%	0.08544 -1%	0.08629 +1%	0.08715 +1%	0.09238 +6%	0.09792 +6%
Distribution Meter ($/day per meter)	1.3705 -8%	1.16350 -15%	1.32710 +14%	1.3456 +1%	1.3719 +2%	1.3953 +2%
PCF Fee ($/GJ)	0	0	TBC	TBC	TBC	TBC

Figure 9 – DWGM Projected Fees



* Real values are the nominal amounts adjusted for inflation. Prices have been calculated relative to the 2016–17 price.

Note: The Energy Tariff D and Tariff V transitioned to a single fee on 1 July 2014.

1.7 Short Term Trading Market (STTM)

The STTM activity fee is budgeted to decrease 13% from $0.07939/GJ to $0.06884/GJ in 2017-18. The 2017-18 fee is lower than the fee of $0.07708/GJ estimated as part of the 2016-17 budget process.

Costs for this function have decreased by $2.5M (27%), mainly due to lower depreciation as the costs of establishing the market will be fully recovered by August 2017.

There is no requirement to collect PCF funds for the Sydney, Brisbane and Adelaide hubs as the current level of funds being held for these hubs meets the Rules requirements. Estimates of future PCF fees are not provided as they are heavily impacted by future claims that may arise from time to time.

Table 13 — STTM Projected Fees

Fee	Actual 2016-17	Budget 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21	Estimate 2021-22
Activity Fee ($/GJ withdrawn)	0.07939 -3%	0.06884 -13%	0.06090 -12%	0.05350 -12%	0.05358 +0%	0.05365 +0%
PCF Fee - Syd ($/GJ withdrawn per hub per ABN)	0	0	TBC	TBC	TBC	TBC
PCF Fee - Adel ($/GJ withdrawn per hub per ABN)	0	0	TBC	TBC	TBC	TBC
PCF Fee - Bris ($/GJ withdrawn per hub per ABN)	0	0	TBC	TBC	TBC	TBC

1.8 Victorian FRC Gas

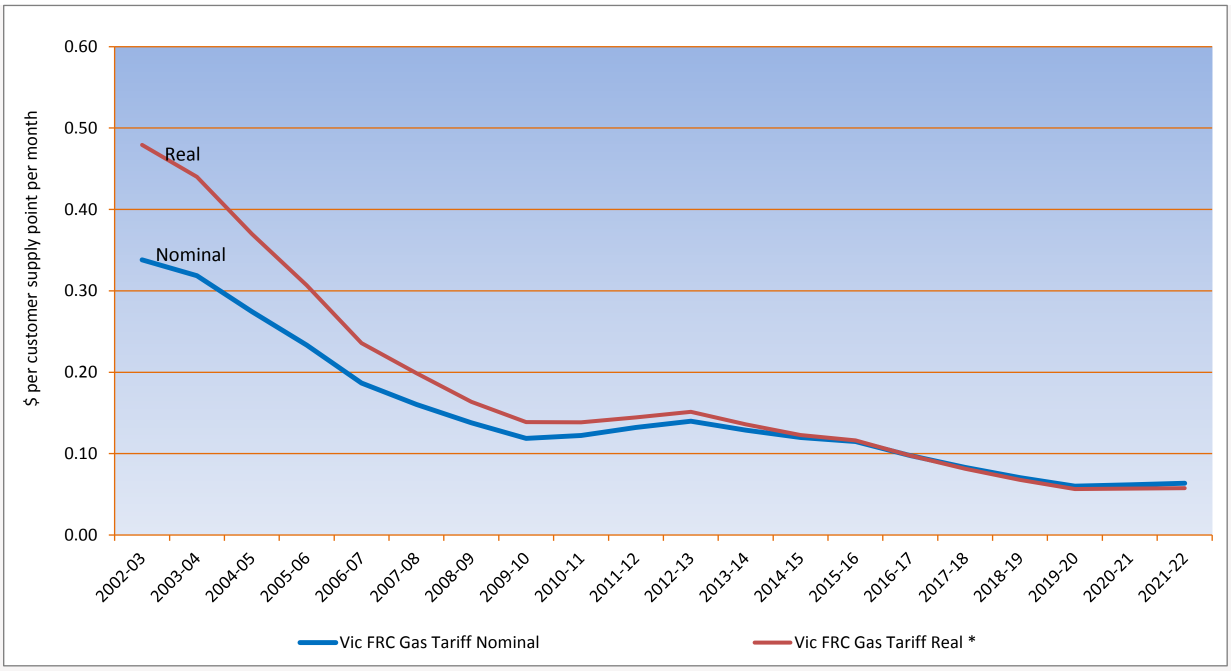
The Victorian FRC fee will reduce by 15% in 2017-18 and by a further 15% in the following two years due to an accumulated surplus from prior years in the function. This is in line with the estimates in last year's budget. The fee is then expected to increase slightly in the following years after the surplus is fully returned to achieve a break-even position.

An initial registration fee is payable in the Victorian FRC Gas Market. It has been retained at the 2016-17 level and will be set annually as part of the budget process.

Table 14 — Victorian FRC Gas Projected Fees

Fee	Actual 2016-17	Budget 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21	Estimate 2021-22
FRC Gas Tariff	0.09771	0.08305	0.07059	0.06000	0.06180	0.06365
($ per customer supply point per month)	-15%	-15%	-15%	-15%	+3%	+3%
Initial Registration Fee ($ per participant)	5,760	5,760	TBC	TBC	TBC	TBC

Figure 10 – Victorian FRC Gas Projected Fees



* Real values are the nominal amounts adjusted for inflation. Prices have been calculated relative to the 2016–17 price.

1.9 Queensland FRC Gas

The Queensland FRC fee will reduce by 15% in 2017-18, and by a further 15% in the following two years due to the return of an accumulated surplus from prior years in the function. This is in line with the estimates in last year's budget.

An initial registration fee is payable in the Queensland FRC Gas Market. It has been retained at the 2016-17 level and will be set annually as part of the budget process.

Table 15 — Queensland FRC Gas Projected Fees

Fee	Actual 2016-17	Budget 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21	Estimate 2020-21
FRC Fee	0.26184	0.22256	0.18918	0.16080	0.16080	0.16080
($ per customer supply point per month)	-15%	-15%	-15%	-15%	+0%	+0%
Initial Registration Fee ($ per participant)	5,760	5,760	TBC	TBC	TBC	TBC

1.10 South Australia FRC Gas

The South Australia FRC fee will reduce by 13% in 2017-18, and by a further 13% in the following two years due to an accumulated surplus from prior years in the function. This is slightly higher than the 11% reduction estimated in last year's budget.

The fee is then expected to remain flat in the following years after the surplus is fully returned to achieve a break-even position.

Costs for this function have decreased by 19%, mainly due to savings in systems costs due to renegotiated contracts.

An initial registration fee is payable in the South Australia FRC Gas Market. It has been retained at the 2016-17 level and will be set annually as part of the budget process.

Table 16 — South Australia FRC Gas Projected Fees

Fee	Actual 2016-17	Budget 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21	Estimate 2021-22
FRC Fee	0.25994	0.22615	0.19675	0.17117	0.16946	0.16777
($ per customer supply point per month)	-11%	-13%	-13%	-13%	-1%	-1%
Initial Registration Fee ($ per participant)	11300	11,300	TBC	TBC	TBC	TBC

1.11 NSW FRC Gas

The NSW FRC Gas 2016-17 fee increase relates to the harmonisation of the NSW and ACT retail gas systems with those in Victoria, Queensland and South Australia. In line with last year's estimates the fee is expected to remain relatively flat in forward years.

Table 17 — NSW FRC Gas Projected Fees

	Actual 2016-17	Budget 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21	Estimate 2021-22
FRC fee	0.16750	0.16918	0.17087	0.17258	0.17258	0.17258
($ per customer supply point per month)	+45%	+1%	+1%	+1%	+0%	+0%

1.12 WA FRC Gas

Accountability for the WA FRC Gas functions transferred from REMCO to AEMO on 31 October 2016.

The 2016-17 fee set by REMCO included a component to collect funding for future IT development work that will be carried out in line with the IT Roadmap. The 2017-18 fee has been reduced as there is no requirement to collect additional future funding for IT development.

Table 18 — WA FRC Gas Fees

Fee		Actual 2016-17	Budget 2017-18
Market Share Charges	$ per customer per month	0.30815	0.13485
Registration Fee	Member	12,951	12,951
	Associate Member	2,590	2,590
Annual Fee	Member	19,905	19,905
	Associate Member	3,881	3,881

1.13 Eastern and South Eastern Gas Statement of Opportunities (GSOO)

The GSOO costs are recovered via charges to retailers in AEMO's FRC gas markets on a fee per meter basis. Costs for this function have increased due to additional work on the National Gas Forecasting Report (NGFR).

The 2017-18 fee is lower than the fee estimated as part of the 2016-17 budget process.

Table 19 — GSOO Projected Fees

Fee	Actual 2016-17	Budget 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21	Estimate 2021-22
Gas Statement of Opportunities	0.03198	0.03518	0.03870	0.04257	0.04257	0.04257
($ per customer supply point per month)	+13%	+10%	+10%	+10%	+0%	+0%

1.14 Gas Supply Hub (GSH)

The GSH voluntary market went live in March 2014.

The 2017-18 fees have been amended to reflect changes in the underlying contract supporting the system and to more accurately reflect the cost of providing the service. The GSH Exchange Agreement requires a consultation process prior to the fees being changed. The consultation process is planned to begin in April 2017.

Table 20 — Gas Supply Hub Fees

Fee		Actual 2016-17	Budget 2017-18
Trading participants	Fixed Fee - one licence per annum	14,500	12,000
	Fixed Fee - additional licence per annum	5,500	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	5,500	3,600

1.15 Gas Bulletin Board (GBB)

The 2016-17 GBB fee was increased to reflect additional work on the system to provide broader scope of data published for production, transmission and storage facilities.

The 2017-18 fees have been set to reflect ongoing maintenance and operational costs.

Table 21 — GBB budget

Fee	Actual 2016-17 ($'000)	Estimate 2017-18 ($'000)	Estimate 2018-19 ($'000)	Estimate 2019-20 ($'000)	Estimate 2020-21 ($'000)	Estimate 2021-22 ($'000)
Gas Bulletin Board	1,646	1,429	1,465	1,513	1,562	1,613
	+14%	-13%	+3%	+3%	+3%	+3%

1.16 Western Australian Gas Services Information (GSI) fees

The GSI comprises the Western Australian Gas Bulletin Board, and the WA Gas Statement of Opportunities.

The reduction in GSI fees from 2016-17 to 2017-18 of 17% is due to the 2017-18 fee being lowered to return a $0.5M surplus from the 2016-17 year.

The revenue for the GSI function is regulated by the WA Economic Regulation Authority (ERA). The current ERA determination concludes on 30 June 2019 and therefore fees beyond this point have not been estimated.

Table 22— GSI projected fees

Fee	Actual 2016-17	Budget 2017-18	Estimate 2018-19	Estimate 2019-20
GSI fee ($'000)	1,834	1,527	1,560	TBC
		-17%	+2%	

1.17 Other Budgeted Revenue Requirements

AEMO also collects revenue to recover the costs of the following functions:

Table 23 — Other Revenue Requirements

Other revenue requirement	Budget 2016-17 ($'000)	Budget 2017-18 ($'000)
South Australia Planning	1,000	1,000
Settlement Residue Auctions	291	295

1.18 Energy Consumers Australia (ECA) fees

In May 2014 the Council of Australian Governments (COAG) Energy Council approved establishment of the ECA to promote the long term interests of energy consumers, in particular for residential customers and small business customers.

AEMO is required to recover the funding for the ECA from market participants.

The below table reflects the fees to be collected in electricity and gas for 2017-18.

Table 24 — ECA requirements

AEMO's ECA Fees	Actual 2016-17	Budget 2017-18
Electricity ($ / connection point for small customers per week)	0.00951 -3%	0.00979 +3%
Gas ($ / customer supply point per month)	0.03183 +2%	0.03199 +1%

CHAPTER 2. AEMO FINANCIALS

2.1 Financials

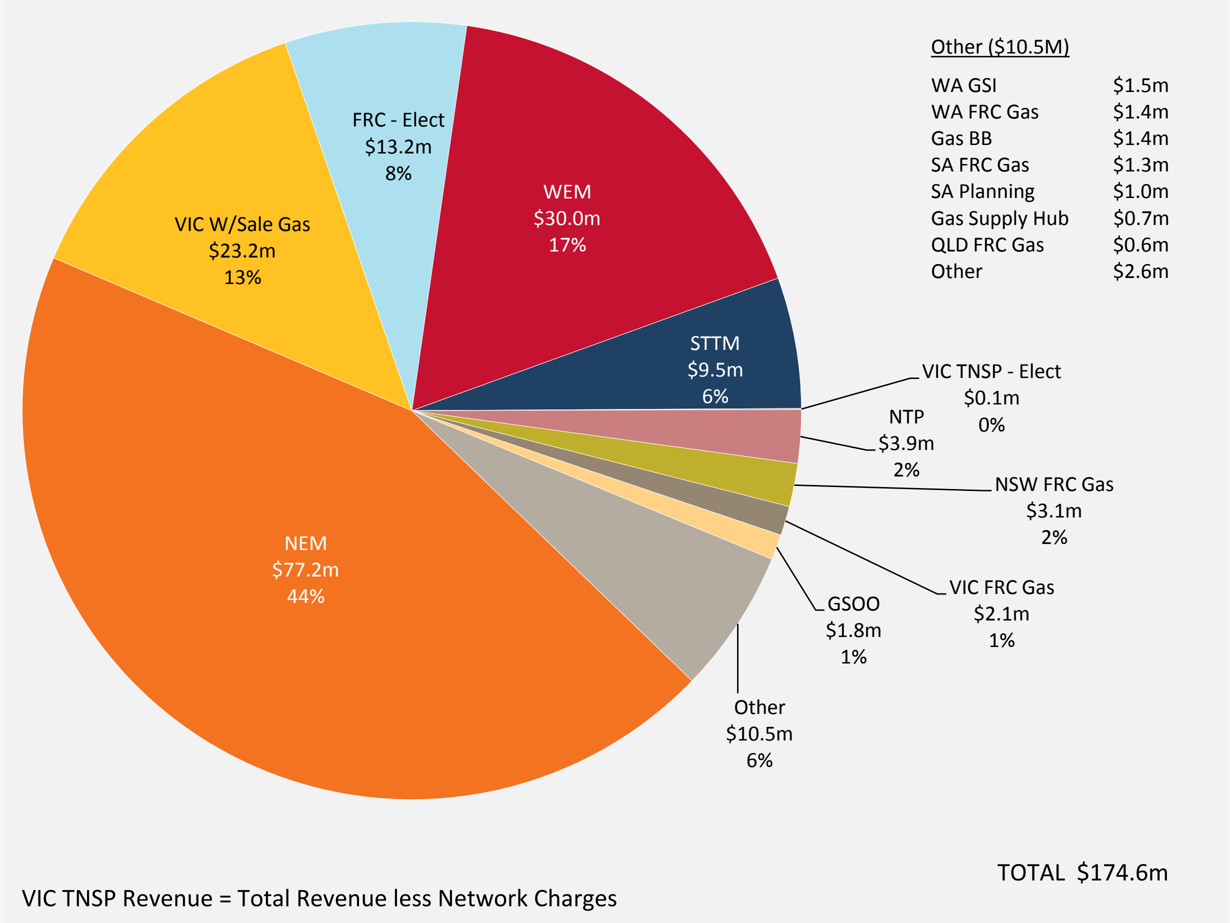
Table 25 — Consolidated Profit and Loss 2017-18

Annual	AEMO (excl. Vic TNSP and WA)				Victorian TNSP				WA Functions				AEMO			
	Budget 2016-17 $'000	Forecast 2016-17 $'000	Budget 2017-18 $'000	Variance to Budget $'000	Budget 2016-17 $'000	Forecast 2016-17 $'000	Budget 2017-18 $'000	Variance to Budget $'000	Budget 2016-17 $'000	Forecast 2016-17 $'000	Budget 2017-18 $'000	Variance to Budget $'000	Budget 2016-17 $'000	Forecast 2016-17 $'000	Budget 2017-18 $'000	Variance to Budget $'000
REVENUE																
Fees and Tariffs	127,195	127,683	134,778	7,584	-	-	-	-	36,795	33,058	32,887	(3,908)	163,990	160,741	167,665	3,675
TUoS Income	-	-	-	-	496,548	483,454	474,580	(21,968)	-	-	-	-	496,548	483,454	474,580	(21,968)
PCF Fees	-	-	1,000	1,000	-	-	-	-	-	-	-	-	-	-	1,000	1,000
Settlement Residue	-	(13)	-	-	26,594	50,271	38,289	11,695	-	-	-	-	26,594	50,258	38,289	11,695
Other Revenue	4,903	5,453	5,817	914	26,456	34,491	35,868	9,412	15	246	50	35	31,375	40,190	41,734	10,360
TOTAL REVENUE	**132,098**	**133,123**	**141,595**	**9,497**	**549,598**	**568,216**	**548,736**	**(862)**	**36,810**	**33,304**	**32,937**	**(3,874)**	**718,506**	**734,643**	**723,268**	**4,761**
NETWORK CHARGES	-	-	-	-	540,011	550,151	548,652	8,640	-	-	-	-	540,011	550,151	548,652	8,640
NET REVENUE	**132,098**	**133,123**	**141,595**	**9,497**	**9,587**	**18,064**	**84**	**(9,503)**	**36,810**	**33,304**	**32,937**	**(3,874)**	**178,495**	**184,491**	**174,617**	**(3,879)**
EXPENDITURE								-								
Total Labour~	84,258	86,719	93,184	8,926	3,881	3,735	4,775	894	19,619	14,008	17,780	(1,839)	107,758	104,462	115,739	7,980
Contractors	1,330	1,772	768	(562)	-	-	-	-	4,483	4,351	83	(4,400)	5,813	6,122	851	(4,962)
Consulting	5,968	5,325	6,843	875	126	126	426	300	6,318	8,287	4,233	(2,084)	12,412	13,738	11,502	(910)
Fees-Agency, Licence and Audit	1,692	1,822	1,705	13	-	-	-	-	798	702	704	(94)	2,489	2,523	2,409	(81)
Information Technology and Telecommunication	16,975	15,952	18,420	1,445	5	5	0	(5)	3,012	3,078	4,636	1,624	19,992	19,035	23,056	3,064
Occupancy	5,475	5,345	5,610	135	-	-	-	-	878	878	1,621	743	6,353	6,223	7,231	879
Training & Recruitment	1,782	1,858	2,113	331	24	24	19	(4)	898	898	732	(166)	2,704	2,780	2,865	161
Travel & Accommodation	1,838	1,843	1,952	115	29	29	20	(9)	319	319	337	17	2,187	2,191	2,309	122
Other Expenses from Ordinary Activities	6,589	6,775	6,538	(51)	3	3	0	(3)	842	824	558	(284)	7,433	7,601	7,096	(337)
TOTAL OPERATING EXPENDITURE (excl Financing & Depreciation)	**125,907**	**127,410**	**137,133**	**11,226**	**4,068**	**3,922**	**5,240**	**1,173**	**37,166**	**33,345**	**30,684**	**(6,482)**	**167,141**	**164,676**	**173,057**	**5,917**
Depreciation and Amortisation	12,225	12,277	11,920	(305)	23	23	7	(16)	6,735	6,179	4,902	(1,833)	18,983	18,479	16,829	(2,154)
Financing Costs	1,456	1,122	586	(870)	-	-	0	0	200	200	58	(142)	1,657	1,323	645	(1,012)
Capitalised internal labour	(4,237)	(3,897)	(5,372)	(1,135)	(2)	(3)	(3)	(1)	(6,200)	(3,370)	(3,603)	2,597	(10,440)	(7,270)	(8,979)	1,461
TOTAL OPERATING EXPENDITURE	**135,351**	**136,912**	**144,267**	**8,916**	**4,088**	**3,941**	**5,244**	**1,156**	**37,900**	**36,355**	**32,041**	**(5,860)**	**177,340**	**177,208**	**181,553**	**4,212**
SURPLUS / (DEFICIT)	**(3,254)**	**(3,790)**	**(2,672)**	**582**	**5,498**	**14,123**	**(5,160)**	**(10,659)**	**(1,090)**	**(3,050)**	**896**	**1,986**	**1,155**	**7,283**	**(6,936)**	**(8,091)**
Transfer to Reserves / Recoveries	2,740	3,205	3,777	1,038	(3,261)	(3,232)	(4,186)	(925)	(209)	(955)	(960)	(751)	(731)	(982)	(1,369)	(638)
Brought Forward Surplus / (Deficit)	18,965	14,514	13,929	(5,035)	(928)	(814)	10,076	11,004	1,644	2,052	(1,953)	(3,597)	19,681	15,752	22,052	2,372
ACCUMULATED SURPLUS / (DEFICIT)	**18,451**	**13,929**	**15,035**	**(3,416)**	**1,309**	**10,076**	**730**	**(579)**	**345**	**(1,953)**	**(2,017)**	**(2,362)**	**20,104**	**22,052**	**13,747**	**(6,357)**
Contributed capital relating to Vic Wholesale gas market	(8,704)	(8,704)	(8,704)	-	-	-	-	-	-	-	-	-	(8,704)	(8,704)	(8,704)	-
ADJUSTED ACCUMULATED SURPLUS / (DEFICIT)	**9,747**	**5,226**	**6,331**	**(3,416)**	**1,309**	**10,076**	**730**	**(579)**	**345**	**(1,953)**	**(2,017)**	**(2,362)**	**11,401**	**13,349**	**5,044**	**(6,357)**

~ Total Labour includes both opex and capex labour.
Note the budgeted 2017-18 accumulated surplus includes $8.7M of contributed capital provided at the inception of the Victorian Wholesale Gas Market.

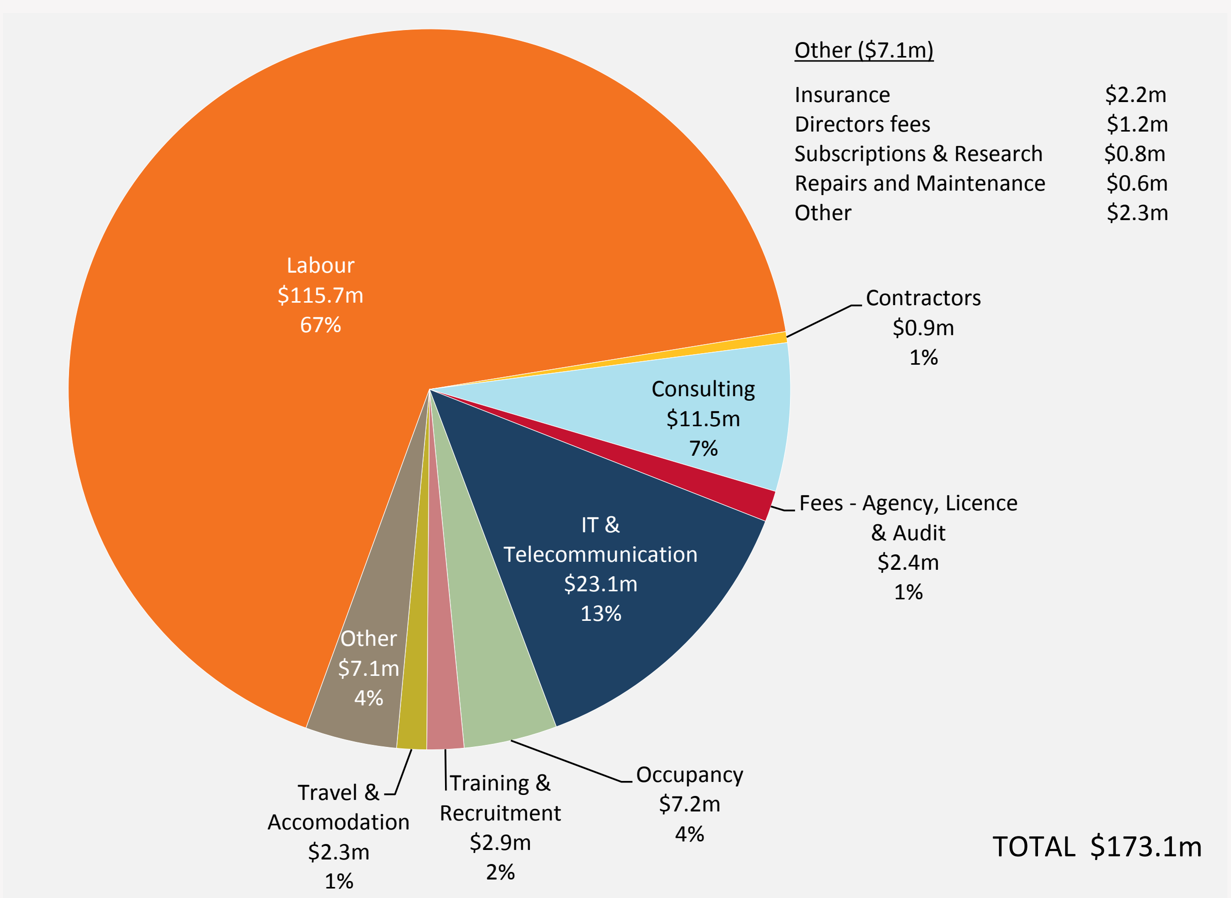
2.2 Net Revenue

Figure 11 – Net revenue by function



2.3 Expenditure

Figure 12 – Total AEMO expenditure by category (excluding depreciation and finance costs)



2.3.1 Expenditure commentary

Total budgeted expenditure (excluding financing costs and depreciation) is $173.1M.

This is an increase of $5.9M (3.5%) from the 2016-17 budgeted expenditure.

Key points are:

- **Labour costs ($115.7M)**

  Labour costs are budgeted to increase by $8.0M (7.4%) compared with the 2016-17 budget.

  The major reasons for the increase are due to an increase in resources in the WA Systems Management function to provide services previously provided via an external services agreement ($2.6M), along with a provision for Enterprise Bargaining Agreement (EBA) increases of 2.9% ($3.1M). The AEMO EBA commenced in 2015 and concludes on 30 June 2018.

- **Contractor costs ($0.9M)**

  Contractor costs are budgeted to decrease by $5.0M (85%) to $0.9M compared to 2016-17 primarily as a result of the completion of a number of the services provided by Western Power.

- **Consulting costs ($11.5M)**

  Consulting costs vary year to year dependent on annual requirements. The 2017-18 budget is lower than the 2016-17 budget by $0.9M.

- **Fees – agency licence and audit ($2.4M)**

  Agency, licence and audit fees in 2017-18 are expected to be at the same level as the 2016-17 budget.

- **IT and telecommunications ($23.1M)**

  IT and telecommunication costs are budgeted to increase by $3.1M (15%) compared to the 2016-17 budget due to:

  – IT support for the WA System Management IT systems, currently provided by Western Power, with a corresponding reduction in contractor's expenditure ($0.6M).

  – Communication links for the new Perth office. This includes links from AEMO east coast, existing WA data centres and Western Power to the new Perth office to allow access to the System Management systems ($1.1M).

  – Increases in software expenditure related to the move to Office 365 and additional enterprise licenses ($0.9M).

  – An IT hardware refresh is budgeted to take place for Market System and Corporate applications ($0.5M).

- **Occupancy ($7.2M)**

  Occupancy costs are budgeted to increase by $0.9M (13%) compared to the 2016-17 budget, mainly due to the new office in Perth ($0.5M) and CPI increases for office leases.

- **Other expenses ($7.1M)**

  Other costs are budgeted to decrease by $0.3M in the 2016-17 budget. The key items include insurance, director fees, repairs and maintenance, subscriptions, research, printing and document management costs.

- **Financing costs ($0.6M)**

  Financing costs are budgeted to decrease by $1.0M (61%) compared to the 2016-17 budget mainly due to renegotiated lower facility costs combined with lower interest paid on the WA, STTM and Norwest loans as the principal outstanding reduces by $10.1M. The loan to establish the STTM will be fully repaid in 2017-18.

- **Depreciation costs ($16.8M)**

  Depreciation costs are budgeted to decrease by $2.2M (11%) compared to the 2016-17 budget mainly due to:

  – The establishment costs for the STTM being fully depreciated in August 2017.

  – The major system in WA Wholesale Electricity Market being fully depreciated in June 2017.

2.4 Project expenditure

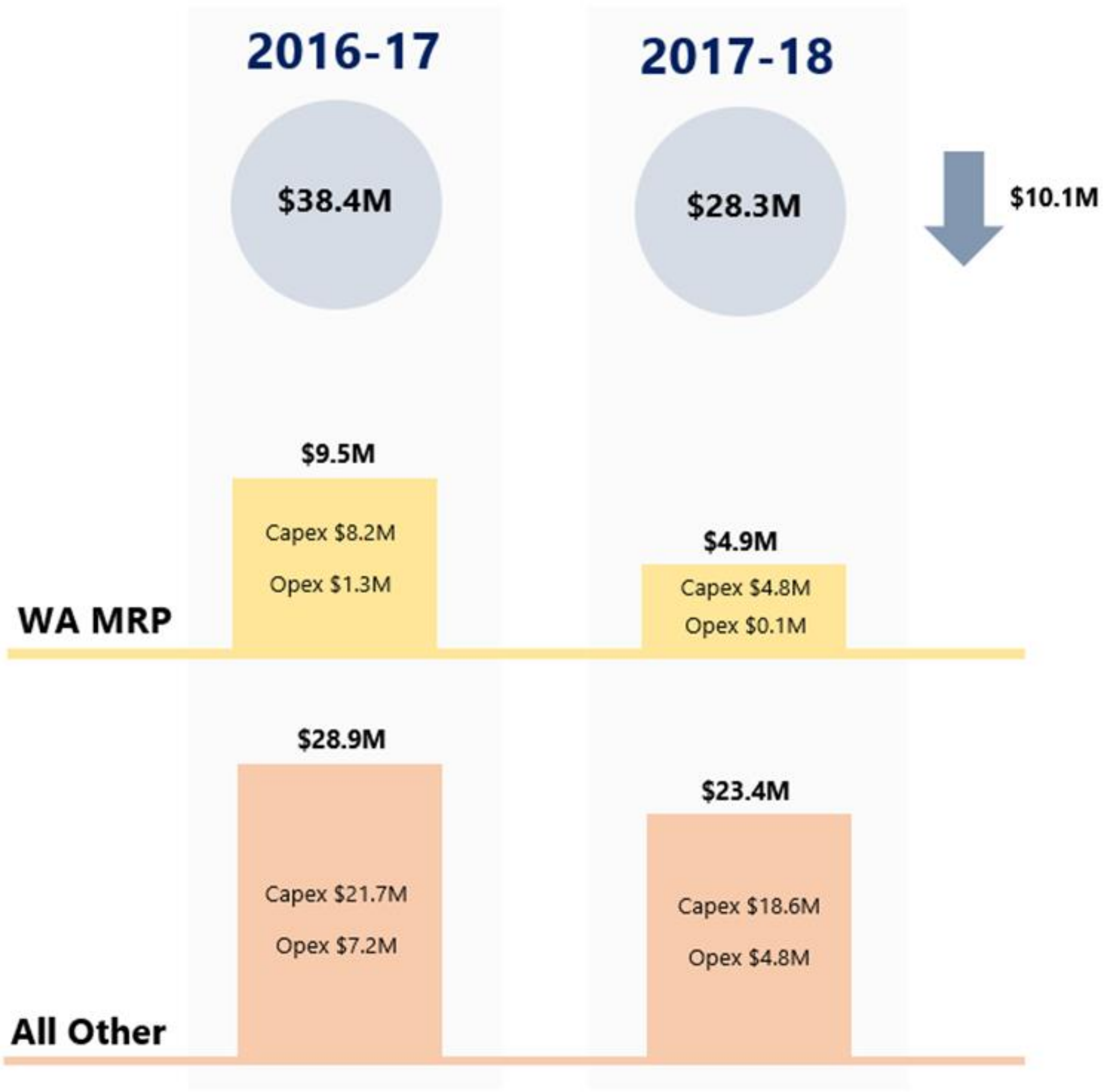
High Level Costings

The proposed project budget for 2017-18 is $28.3M, which is $10.1M less than 2016-17.

This variation is due in large part to:

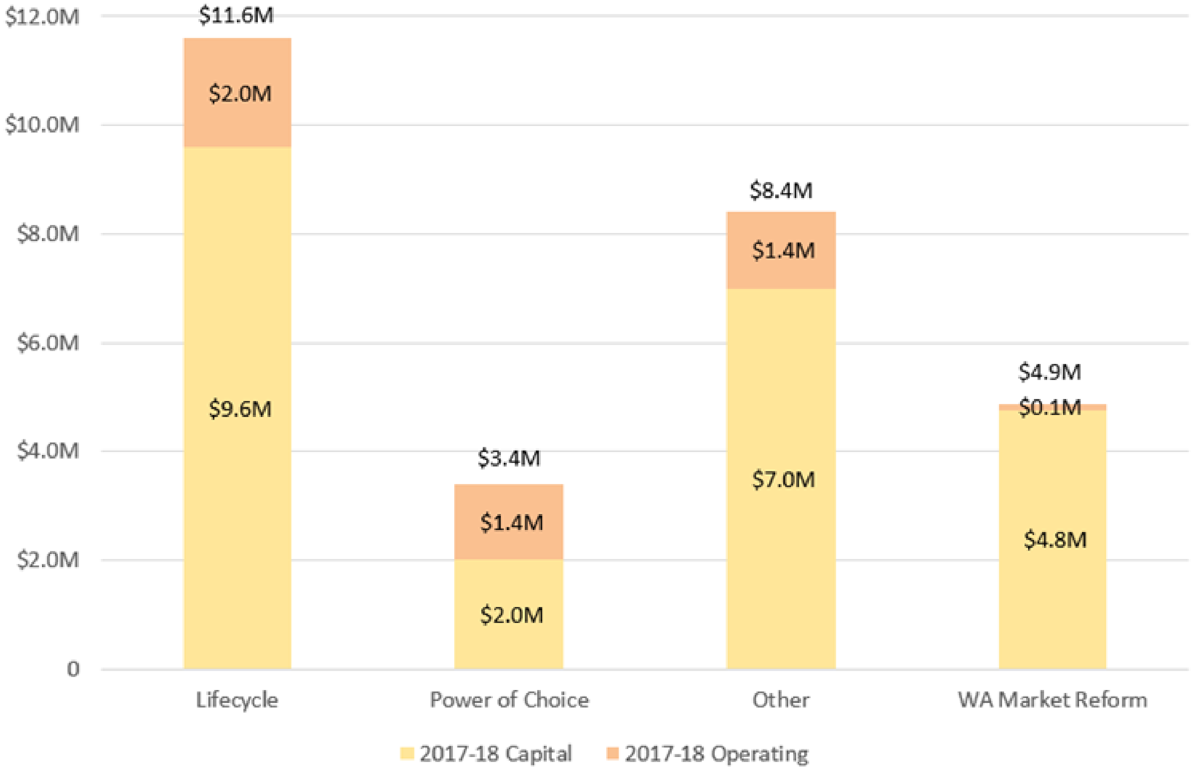
- The completion of the Power of Choice program of work by December 2017.
- The 2017-18 WA Market Reform budget is based on a reduced scope of work until there is further clarity on WA energy policy. The budget is consistent with the submission made to the Western Australian Economic Regulatory Authority (ERA) in February 2017.

Figure 13 – Project expenditure 2017-18



2.4.1 Project Expenditure by Category

Figure 14 – Project expenditure 2017-18



Lifecycle projects include:

- EMP Upgrade ($3.0M) – A project to upgrade AEMO's Energy Management Platform (EMP) to the latest current and supported versions from a platform that is in legacy support.
- Melbourne Data Centre Works ($1.6M) – A project to retire the Melbourne Data Centre, consolidate and move to co-location data centre services, reducing costs. Additionally, upgrade aged Melbourne office networking hardware to maintain supportability.
- Oracle V12 EMMS and ANEMOS ($1.6M) - Migrate the Electricity Market Management System (EMMS) and ANEMOS (Wind Forecasting System) databases to SQL databases to consolidate systems and reduce resource and annual maintenance costs.
- Gas Wholesale Database System Replacement ($1.0M) – A project to migrate the Declared Wholesale Gas Market (DWGM) from Sybase to SQL Databases to consolidate systems and reduce resource and annual maintenance costs.

Power of Choice projects include:

- The Power of Choice Program aims to design and implement changes to electricity metering and retail market arrangements, and associated infrastructure, to operationalise rule-changes arising from the Australian Energy Market Commission's (AEMC) Power of Choice review.

Other projects include:

- WA Perth Office Move ($2.3M) – Project to consolidate and move all WA AEMO staff and facilities into a single AEMO office in Perth to create a single integrated System and Market Operator.
- Consolidated Forecasting and Planning Publication Project ($0.9M) – A project to consolidate and modernise the delivery of the forecasting and planning publications, provide greater insights and reduce publication development times.
- Site Address Standardisation ($0.7M) – Regulatory project to allow participants better discovery and reduce customer transfer errors.

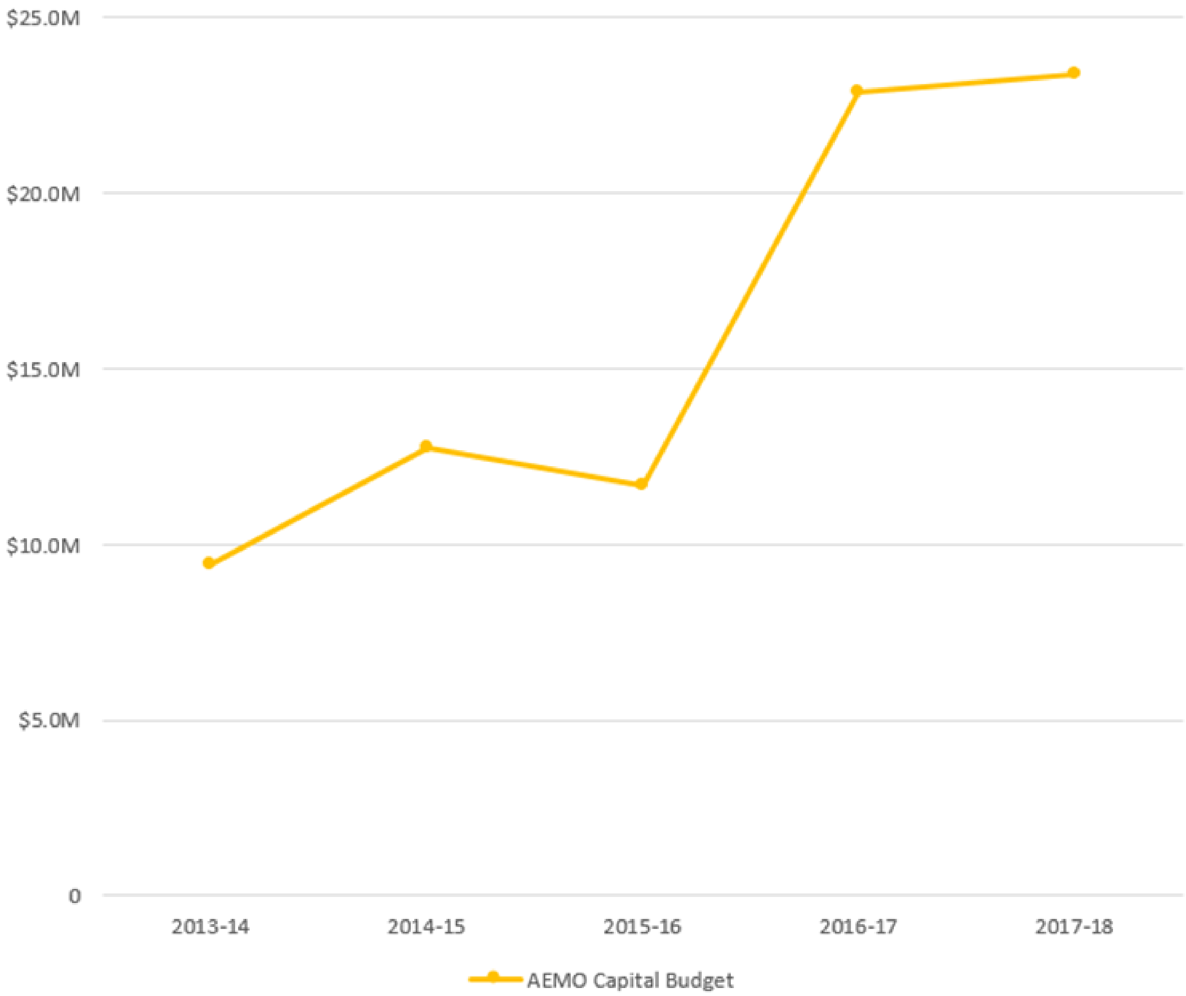
WA Market Reform include:

- The WA Reform Program budget is consistent with the submission made to the WA Economic Regulatory Authority (ERA) in February 2017. The submission is only for the period up to December 2017 and reflects an approach of significantly reducing spend and focussing on critical activities only until there is further clarity on the reform program following the Western Australian election.

2.4.2 Capital Expenditure budget trend

The significant increases in capital expenditure over 2016-17 and 2017-18 primarily relate to the Power of Choice and WA Market Reform programs of work.

Figure 15 – Capital expenditure trend



Emerging Work

The capital project budget proposal excludes a number of emerging initiatives that are not sufficiently developed for a budget estimate to be made. These include:

- WA Market Reform Program Changes (beyond December 2017).
- Outcomes of external reviews into the South Australian system security event.
- East Coast Gas Review.
- REMCO Integration and Program.

2.5 Balance Sheet 2017-18

Table 26 — Balance Sheet 2017-18

	Forecast 2016-17 $'000	Budget 2017-18 $'000	Variance $'000	%
ASSETS				
Current Assets				
Cash and Short Term Deposits	30,322	17,998	(12,324)	-68%
Receivables	67,112	65,628	(1,484)	-2%
Other Current Assets	4,044	3,979	(65)	-2%
Total Current Assets	101,478	87,605	(13,873)	-16%
Non - Current Assets				
Intangible Assets - Software	33,653	39,799	6,147	+15%
Property, Plant and Equipment	34,237	34,387	151	+0%
Total Non Current Assets	67,890	74,187	6,297	+8%
TOTAL ASSETS	169,368	161,792	(7,576)	-5%
LIABILITIES				
Current Liabilities				
Payables	73,213	74,399	1,186	+2%
Borrowings	3,226	1,842	(1,384)	-75%
Provisions	21,560	22,421	861	+4%
Other Current Liabilities	15,839	15,839	-	+0%
Total Current Liabilities	113,838	114,501	663	+1%
Non - Current Liabilities				
Borrowings	13,022	11,200	(1,822)	-16%
Provisions	1,774	1,828	53	+3%
Lease Liability	3,738	4,204	466	+11%
Total Non Current Liabilities	18,535	17,232	(1,303)	-8%
TOTAL LIABILITIES	132,373	131,733	(640)	-0%
NET ASSETS / (LIABILITIES)	36,995	30,059	(6,936)	
EQUITY				
Capital contribution	7,093	7,093	-	+0%
Participant compensation fund reserve	5,357	6,499	1,141	+18%
Land reserve	2,493	2,719	227	+8%
Accumulated surplus/(deficit)	22,053	13,749	(8,304)	-60%
TOTAL EQUITY	36,995	30,059	(6,936)	

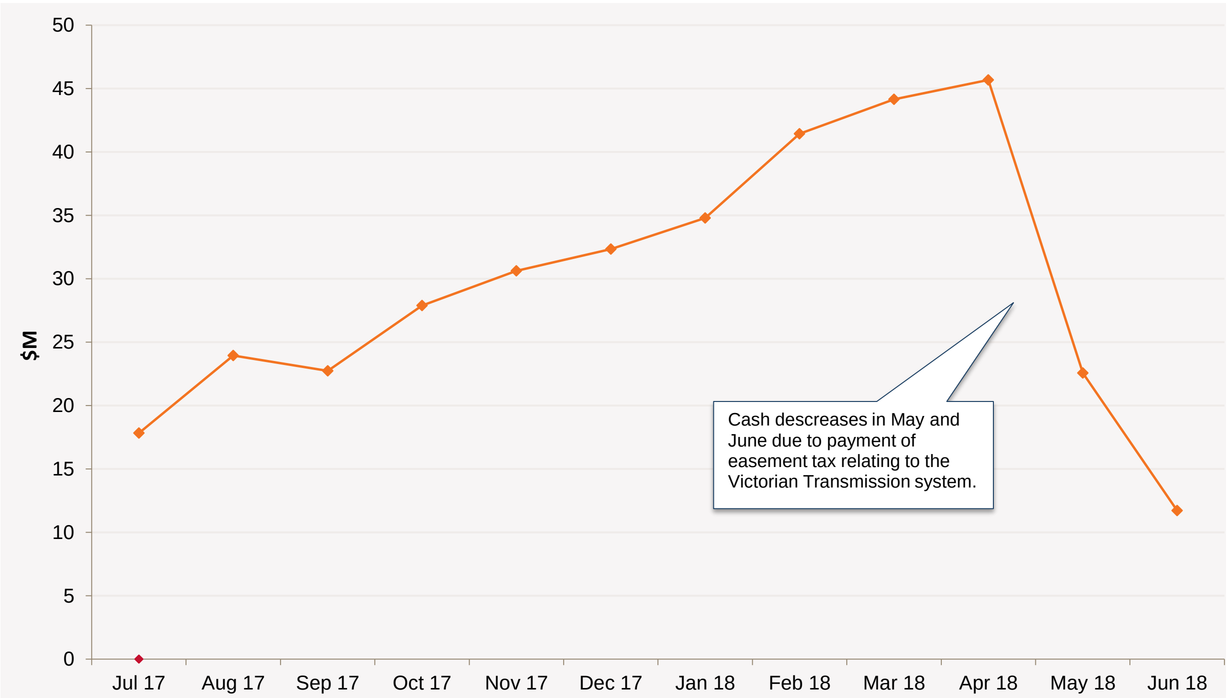
2.6 Cash Flow Statement 2017-18

Table 27 — Cash Flow 2017-18

	Budget 2017-18 $'000
Cash at the beginning of the period (including PCF) at 1 July 2017	**30,322**
Estimated Receipts	797,130
Estimated Payments	(806,247)
Proceeds from borrowings	-
Repayment of borrowings	(3,206)
Cash at the End of Period (including PCF) at 30 June 2018	**17,998**
Less: PCF Funds	(6,362)
Cash at the End of Period (excluding PCF) at 30 June 2018	**11,636**

The figure below reflects the monthly expected cash balance (excluding PCFs) for 2017-18.

Figure 16 – Expected closing cash balance (excluding PCF) for 2017-18.



LIST OF SYMBOLS AND ABBREVIATIONS

Term	Definition
AER	Australian Energy Regulator
AEMC	Australian Energy Market Commission
AWEFS	Australian Wind Energy Forecasting System
B2B	Business-to-Business
DWGM	Declared Wholesale Gas Market
ERA	Economic Regulation Authority
FRC	Full Retail Contestability
GBB	Gas Bulletin Board
GJ	Gigajoule
GSOO	Gas Statement of Opportunities
ESOO	Electricity Statement of Opportunities
IMO	Independent Market Operator
LNG	Liquefied Natural Gas
MOS	Market Operator Service
MW·h	Megawatt hour
NA	Not Applicable
NEM	National Electricity Market
NGERAC	National Gas Emergency Response Advisory Committee
NGR	National Gas Rules
NSM	National Smart Metering
NTP	National Transmission Planner
PCF	Participant Compensation Fund
SRA	Settlement Residue Auction
STTM	Short Term Trading Market
TNSP	Transmission Network Service Provider
TUOS	Transmission Use of System
WEM	Wholesale Electricity Market
GSI	Gas Services Information

APPENDIX A. FEE SCHEDULES

Fee schedule of Electricity Functions

Function	Budget 2017-18 $'000	Rate	Paying Participants
NEM			
General Fees (unallocated)	22,386	$0.12307/ MW·h of customer load	Market Customers
Allocated Fees			
Market Customers	28,207	$0.15507/ MW·h of customer load	Market Customers
Generators[1] and Market Network Service Providers	24,028	Daily rate calculated on 2016 capacity/ energy basis	Generators and Market Network Service Providers
Participant Compensation Fund	1,000	Daily rate calculated on capacity/ energy basis	Scheduled Generators, Semi-Scheduled Generators and Scheduled Network Service Providers
Registration fees	426		Intending Participants
Other	1,138		Dependent on service provided
TOTAL NEM	**77,186**		
FRC ELECTRICITY			
FRC Operations	12,883	$0.07500/ MW·h of customer load in jurisdictions with FRC	Market Customers with a Retail Licence
Other	273		Dependent on service provided
TOTAL FRC ELECTRICITY	**13,156**		
WEM			
Market Operator	13,534	$0.357/ MW·h of forecast generation and customer load	Market Customers and Generators
System Operator	16,463	$0.434/ MW·h of forecast generation and customer load	Market Customers and Generators
TOTAL WEM	**29,998**		
National Transmission Planner	3,867	$0.02126/ MW·h of customer load	Market Customers
Energy Consumers Australia	5,002	$0.00979/ connection point for small customers/ week	Market Customers
Additional Participant ID		$5,000 per additional participant ID	Existing Participants

[1] Excluding non market non scheduled generators

Fee schedule of new Electricity registrations

Application Type	2017-18 $
Registration as Scheduled Market Generator[1]	20,000
Registration as Semi-Scheduled Market Generators	20,000
Registration as Scheduled Non-Market Generator	10,000
Registration as Semi-Scheduled Non-Market Generators	10,000
Registration as Non-Scheduled Market Generator	10,000
Registration as Market Customer	10,000
Registration as Market Small Generation Aggregator	10,000
Transfer of Registration	10,000
Registration as Metering Co-ordinator (MC)[2]	10,000
Registration as Market Ancilliary Service Provider	10,000
Registration as Non-Scheduled Non-Market Generator	5,000
Registration as Network Service Provider	5,000
Registration as Trader	5,000
Registration as Reallocator	5,000
Classification of generating units for frequency control ancillary services purposes	5,000
Classification of load for frequency control ancillary services purposes - new ancilliary service load or aggregated ancillary service load	5,000
Registration as Intending Participants	2,000
Exemption from registration	2,000

[1] Each category of *Generator* in this table includes applications made by persons intending to act as intermediaries.

[2] The registration fee will not apply to Network Operators that become the Initial Metering Coordinator from 1 December 2017 and Metering Coordinator for Type 7 meters (unmetered load).

Fee schedule of new WA WEM registrations

Application Type	2017-18 $
Rule Participant Registration Application Fee	680
Facility Registration Application Fee	340
Facility Transfer Application Fee	390
Conditional Certification of Reserve Capacity	680
Resubmission – Application for Early Certified Reserve Capacity	6,215

Fee schedule of new Power of Choice accreditations

Application Type	2017-18 $
Embedded Network Manager	2,000
Metering Data Providers	5,000
Metering Providers	5,000
Incremental charge rate per hour	150

Fee schedule of Gas Functions

Function	Rate 2017-18	
Vic Wholesale Gas		
Energy Tariff	0.08544	$/GJ withdrawn
Distribution Meter	1.16350	$/day per meter
PCF	Nil	$/GJ withdrawn
VIC Gas FRC	0.08305	$ per customer supply point/ mth
QLD Gas FRC	0.22256	$ per customer supply point/ mth
SA Gas FRC	0.22615	$ per customer supply point/ mth
NSW/ ACT Gas FRC	0.16918	$ per customer supply point/ mth
WA Gas FRC	0.13485	$ per customer supply point/ mth
STTM		
Activity Fee	0.06884	$/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	0.03199	$ per customer supply point/ wk
GSOO	0.03518	$ per customer supply point/ mth
GSI	1,527	$'000
Additional Participant ID	5,000	$ per additional participant ID