CONSOLIDATED FINAL BUDGET AND FEES 2016–17

AUSTRALIAN ENERGY MARKET OPERATOR

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EXECUTIVE SUMMARY

Introduction

The 2016-17 final budget provides a consolidated view of AEMO's 201617 revenue and expenses, fees for 2016-17, and estimates for the following four-year period.

The energy market landscape is shifting, with a decline in energy consumption expected to continue in the gas markets, and a forecast of flat growth for electricity, which is placing pressure on AEMO fees charged to participants.

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

As a result, most fees are in line with or lower than prior year published estimates, except for the Electricity Full Retail Contestability (FRC) fee.

Key messages

The key messages of the 2016-17 budget are:

1. **AEMO's 2016–17 total budget expenditure (excluding WA functions) is $141.2M; which is $0.4M lower than the 2015-16 budget. The key 2016-17 fees consists of:**
    - National Electricity Market (NEM) fee – $0.39/MWh is in line with last year's published budget estimate.
    - Electricity Full Retail Contestability (FRC) – $0.061/MWh (is 15% higher than the estimated $0.053/MWh estimated in last year's fee projections). This fee is higher than the estimated fee published last year due to the increased scope of Power of Choice projects.
    - Declared Wholesale gas Market (DWGM) fee – down 2% (compares favourably with the +7% estimated in last year's fee projections) to return a forecast 2015-16 surplus and reflect a higher consumption forecast for 2016-17.
    - Short Term Trading Market (STTM) fee – down 3% (-2% estimated in last year's fee projections).

2. **Projects outlined in the 2016–17 budget that link to AEMO's 2015–17 strategic initiatives**
    - Forecasting and planning – increased information updates on forecast scenarios and insight publications on emerging challenges.
    - Emerging technologies and developments – adapt AEMO's capability to maintain the security and reliability of the power system in the changing market environment. AEMO is conducting impact analysis to review the changing generation mix, battery storage, and increasing consumer engagement over a three-year and 10-year outlook.
    - Power of Choice reforms – facilitate greater retail competition in the NEM by ensuring the community's demand for electricity services is met by the lowest cost combination of demand and supply-side options, through new and improved initiatives in electricity metering competition, retail market arrangements such as embedded networks and shared market protocols, and associated infrastructure.
    - IT systems – transform IT systems and services to meet the needs of a changing industry through improvements and investment in IT architecture, data centre services, and data system initiatives.

3. Continued focus on workforce planning and labour costs

- The 2.9% increase in employee costs negotiated in the 2015 Enterprise Agreement has been largely absorbed in the salary base.
- A number of vacant positions have been replaced by developing and / or hiring targeted technical and specialist skills to achieve and leverage a better skill mix within the organisation.

4. IT cost savings fund AEMO's IT transformation roadmap

- In the past year, AEMO has reduced IT costs through renegotiating telecommunications provider service agreements to run its Data Link and MarketNet platforms.
- AEMO's new external data centre, funded by the reduction of in-house data centre costs at the former Mansfield site, has already translated to higher quality data centre services and outcomes.
- The reduction of depreciation costs relating to some IT systems will provide future opportunities to replace legacy IT technology and increase business efficiency.

5. Western Australian functions

- On 30 November 2015 AEMO assumed responsibility for Western Australian market functions previously performed by the Independent Market Operator.

  From 1 July 2016, AEMO will assume responsibility for Systems Management functions in Western Australia, currently performed by Western Power.

  For the Western Australian functions, the revenue that AEMO recovers from participants needs to be approved by the Western Australian Economic Regulation Authority (ERA). In this document, the 2016-17 budget for the WA functions has been based on the Allowable Revenue submissions made to the ERA. The ERA is yet to make a determination on the submissions.
- Systems Management - From 1 July 2016, AEMO will also assume responsibility for Systems Management functions in Western Australia, currently performed by Western Power. The 2016-2019 budget for Systems Management was submitted to the Economic Regulation Authority (ERA) for approval. The Systems Management allowable revenue information is included in this report in section 1.18.

Table 1 provides a comparison of 2016-17 budgeted expenditure with prior years.

Table 1 — AEMO budgeted expenditure

Budget year	2014-15	2015-16	2016-17
Existing functions	$141.5M	$141.2M	$140.8M
% change	*-1.5%*	*-0.2%*	*-0.3%*
W.A. functions		$19.8M	$19.4M
% change			*-2%*
Total	**$141.5M**	**$161.0M**	**$160.2M**

2016-17 Fees

Table 2 — Key fees

Function	Budget 2016-17	Current 2015-16	Change	Prior year published estimate 2016-17	Unit
Electricity					
NEM	0.39	0.38	4%	0.39	$/MWh
FRC - Electricity	0.061	0.040	53%	0.053	$/MWh
National Transmission Planner	0.01606	0.02054	-22%	0.02421	$/MWh
VIC TNSP - TUOS Fees	496,548	512,354	-3%	515,647	$'000
WEM	1.008	1.008	0%	N/A	$/MWh
Gas					
DWGM - Energy Tariff	0.08630	0.08806	-2%	0.0942	$/GJ withdrawn
STTM - Activity Fee	0.07939	0.08193	-3%	0.0807	$/GJ withdrawn
VIC FRC Gas	0.09771	0.11495	-15%	0.1104	$ per customer supply point per month
QLD FRC Gas	0.26184	0.30805	-15%	0.3081	$ per customer supply point per month
SA FRC Gas	0.25994	0.29207	-11%	0.2804	$ per customer supply point per month
NSW & ACT FRC Gas	0.16750	0.11586 [1]	45%	N/A	$ per customer supply point per month
Gas Statement of Opportunities	0.03198	0.02830	13%	0.03255	$ per customer supply point per month
Gas Supply Hub - daily	0.03	0.03	0%	N/A	$/GJ
Gas Supply Hub - weekly	0.02	0.02	0%	N/A	$/GJ
Gas Supply Hub - monthly	0.01	0.01	0%	N/A	$/GJ
Gas Bulletin Board	1,646	1,441	14%	N/A	$'000
Gas Services Information	1,834	1,834	0%	N/A	$'000
Other					
SA Planning	1,000	1,000	0%	N/A	$'000
Settlement Residue Auctions	291	253	15%	N/A	$'000
ECA (Electricity)	0.00951	0.00976	-3%	N/A	$ per connection point for small customer per week
ECA (Gas)	0.03183	0.03114	2%	N/A	$ per customer supply point per month
System Management	0.372	0.372	0%	N/A	$/MWh

[1] Indicative fee provided for comparison purposes only.

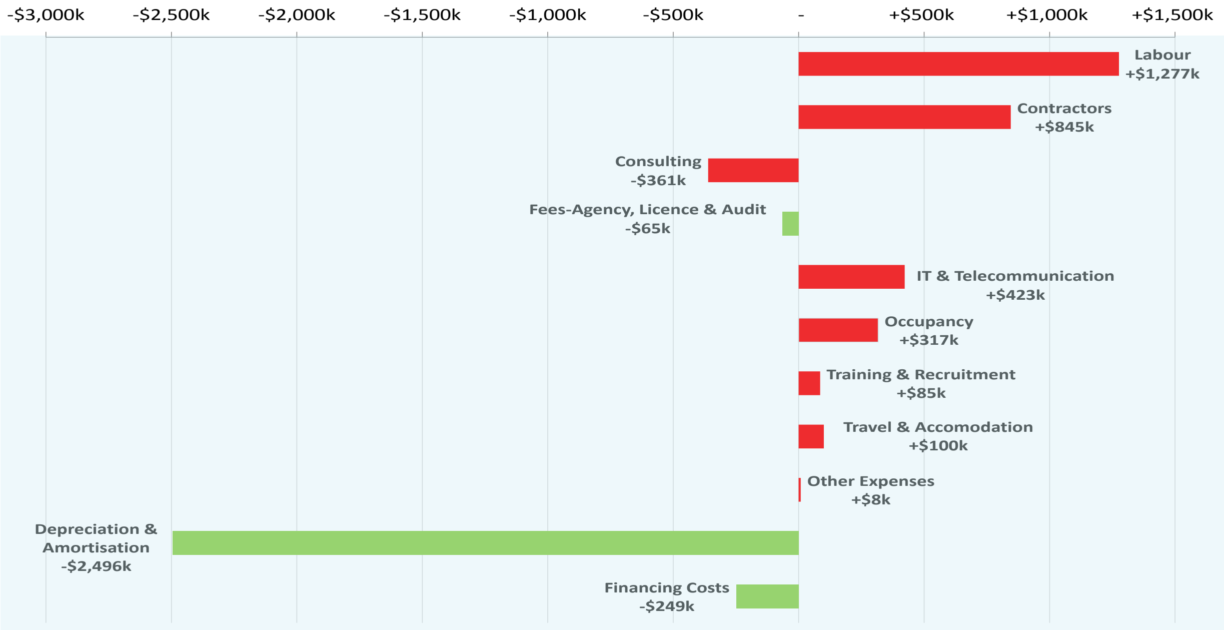
2016-17 expenditure by category

AEMO functions (excluding WA functions)

The total budgeted AEMO functions spend in 2016-17 of $140.8M is $0.4M (0.3%) lower than 2015-16. More information on the expenditure variances is explained in Section 2.3.

Figure 1 compares by spend category on AEMO functions 2016-17 budget to 2015-16.

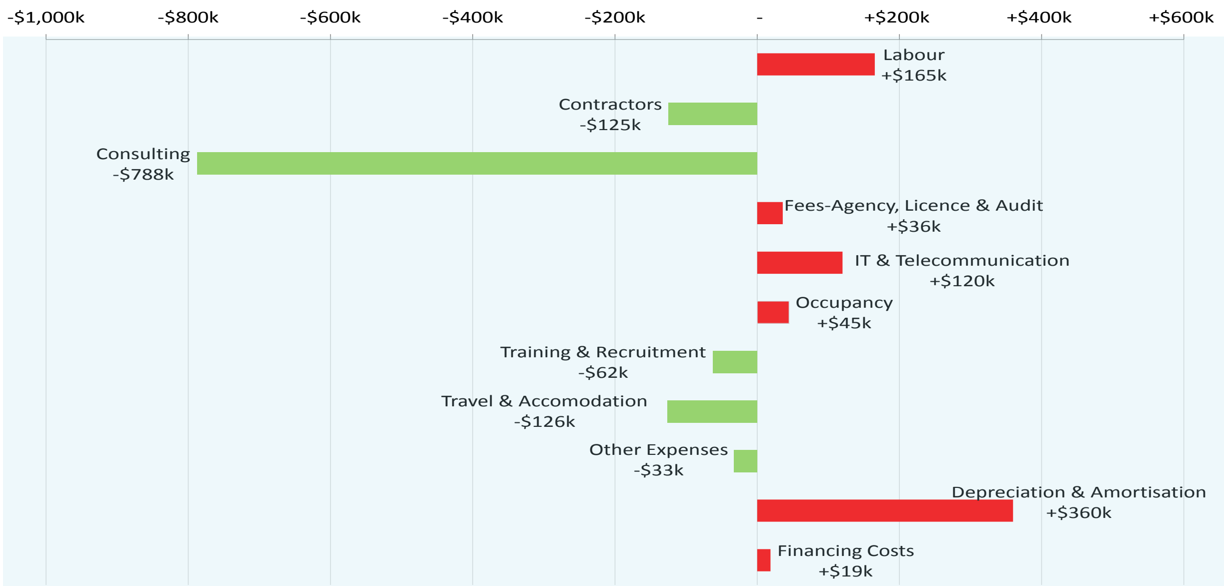
Figure 1 – Comparison of expenditure by category (AEMO excluding WA functions)



Western Australian functions

The total budgeted Western Australian functions spend in 2016-17 of $19.4M is $0.4M (2%) lower than 2015-16 (full 12 month data used for comparison purposes).

Figure 2 – Comparison of expenditure by category (Western Australian functions)



Energy consumption

National Electricity Market

The final forecast consumption for 2016-17 is based on available data estimates used in the 2016 National Electricity Forecast Report (NEFR) to be published in June 2016.

The 2016-17 and future years consumption (excluding Liquefied Natural Gas (LNG)) is expected to be flat as the decrease in consumption due to solar PV and energy efficiency is offset by population growth. The industrial consumption is also flat.

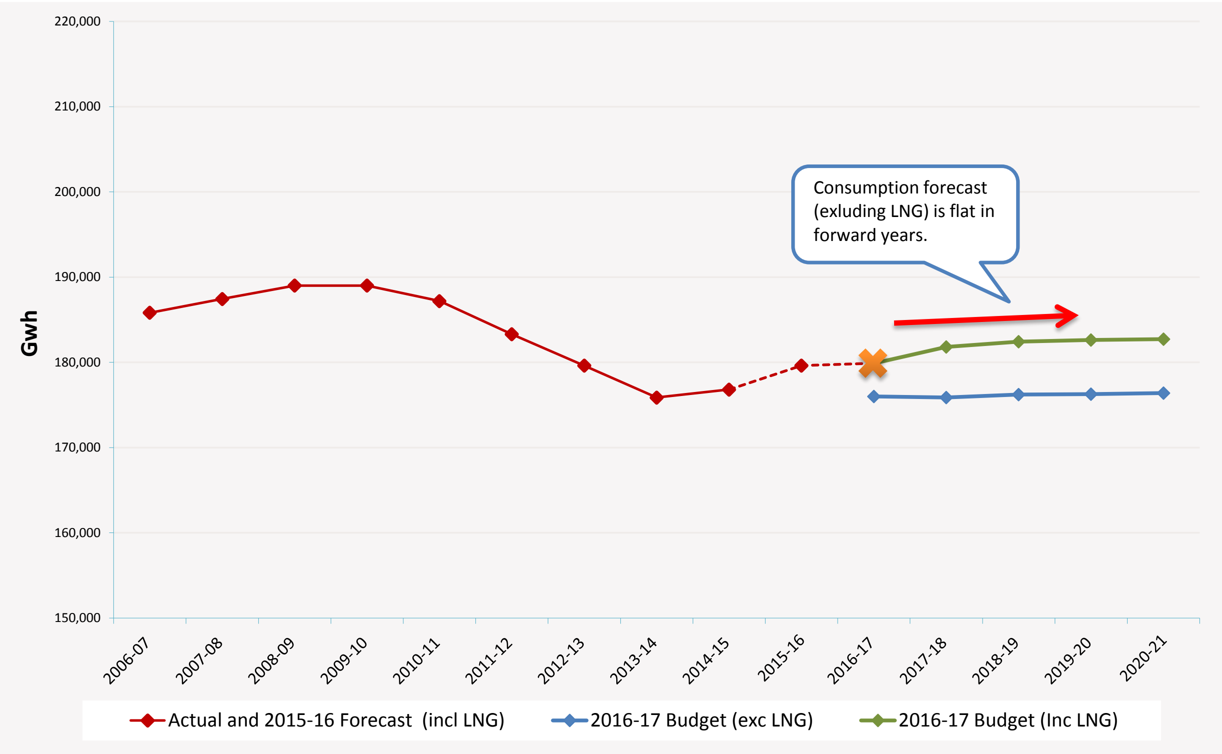
Table 3 — NEM consumption

GWh	Budget 2015-16	Forecast [1] 2015-16	Budget 2016-17	Estimate 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21
NEM (excluding LNG)	174,281	175,586	176,012	175,880	176,218	176,280	176,392
LNG	3,846	4,027	3,881	5,925	6,211	6,341	6,341
TOTAL	**178,127**	**179,614**	**179,893**	**181,805**	**182,430**	**182,621**	**182,732**
			+1.0%	+1.1%	+0.3%	+0.1%	+0.1%

[1] Forecast annual 2015-16 consumption as at April 2016

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

Figure 3 – Annual electricity consumption (market customer load)



Victorian Declared Wholesale Gas Market

The final forecast consumption is based on the National Gas Forecasting Report (NGFR) published in December 2015.

AEMO estimates in 2016-17 an overall increase of 4.7% in consumption from the 2015-16 budget due to increases in Victorian exports to NSW, and increased domestic consumption, offset by decreases in industrial consumption. Industrial consumption is estimated to decline from 2016-17.

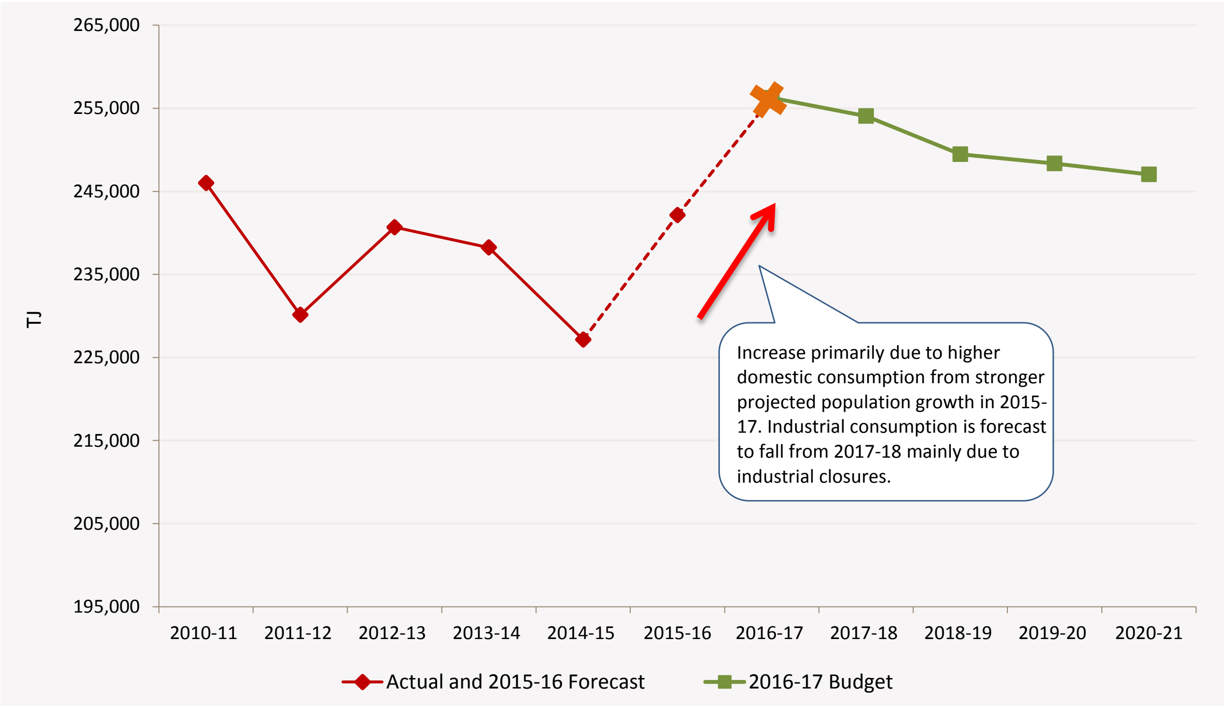
Table 4 — DWGM consumption

TJs	Budget 2015-16	Forecast [1] 2015-16	Budget 2016-17	Estimate 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21
Tariff V (Domestic)	119,396	126,336	125,822	125,295	124,117	123,167	122,065
Tariff D (Industrial)	74,039	72,534	72,144	68,963	66,033	65,847	65,710
Export	39,447	39,116	45,664	47,996	48,756	49,000	49,000
GPG	2,254	4,157	2,500	2,500	2,500	2,500	2,500
TOTAL	**235,136**	**242,142**	**246,130**	**244,754**	**241,406**	**240,513**	**239,275**
			+4.7%	-0.6%	-1.4%	-0.4%	-0.5%

[1] Forecast annual 2015-16 consumption as at April 2016

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

Figure 4 – Annual DWGM consumption



Short Term Trading Market

Consumption in the STTM is expected to decline over five years.

This is mainly driven by the Brisbane hub with planned closures of large industrial companies as well as lower backhaul and gas powered generation (GPG).

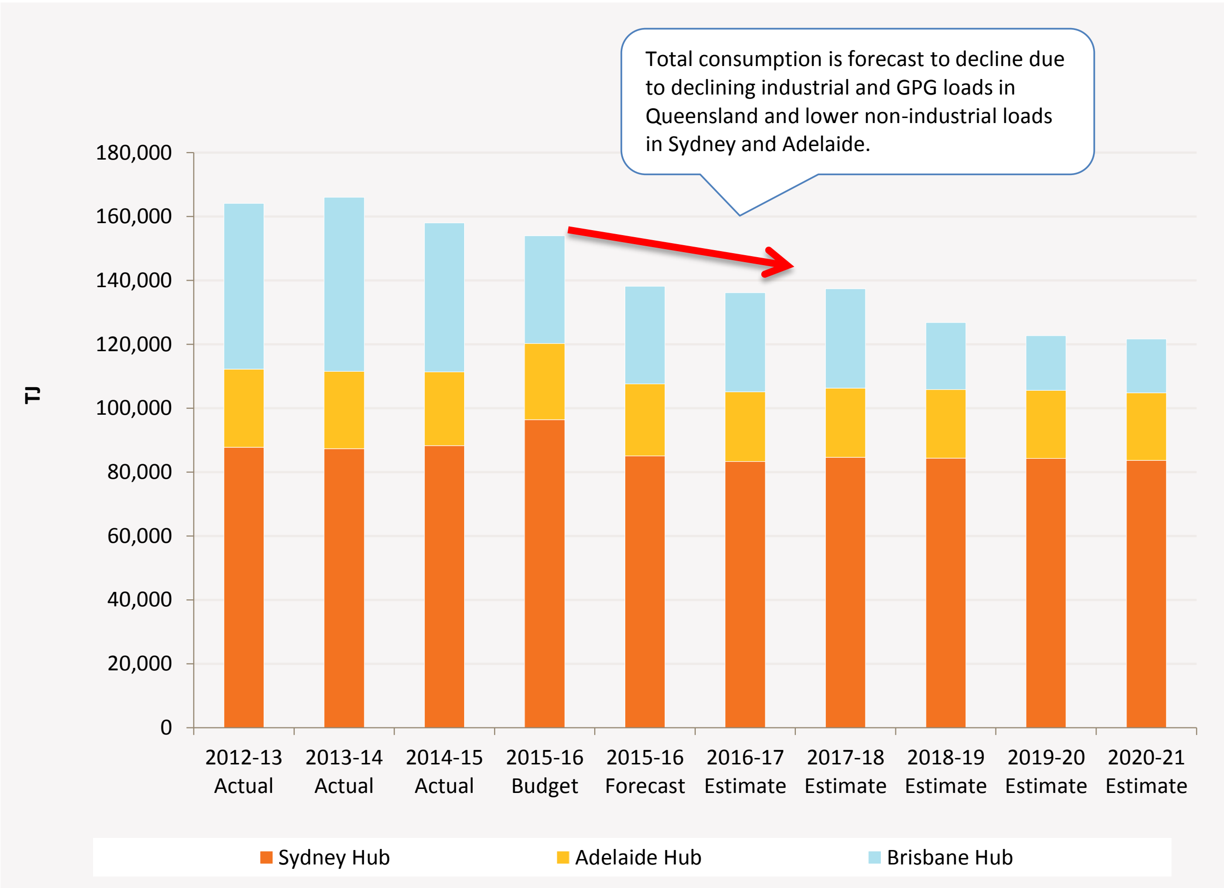
Table 5 — STTM consumption

TJs	Budget 2015-16	Forecast [1] 2015-16	Budget 2016-17	Estimate 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21
Adelaide	23,913	22,618	21,835	21,752	21,464	21,313	21,182
Brisbane	33,690	30,526	31,062	31,027	20,988	17,175	16,883
Sydney	96,392	85,021	83,304	84,581	84,383	84,240	83,643
TOTAL	**153,994**	**138,166**	**136,201**	**137,360**	**126,835**	**122,728**	**121,707**
			-11.6%	+0.9%	-7.7%	-3.2%	-0.8%

[1] Forecast annual 2015-16 consumption as at April 2016

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

Figure 5 – Annual STTM Gas consumption



Western Australia Wholesale Electricity Market

The Western Australia Electricity Statement of Opportunities provides the Wholesale Electricity Market (WEM) consumption data.

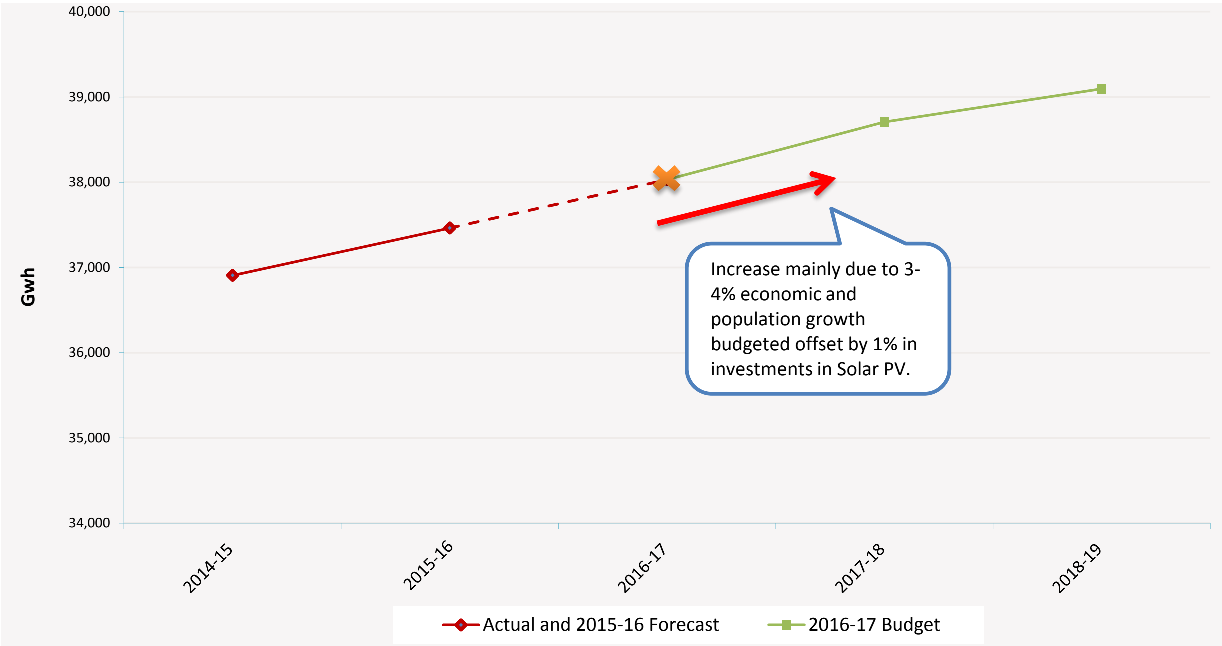
Consumption is expected to increase due to increased economic and population growth in Western Australia of between 3 – 4% per year, offset by investments in solar PV (1%).

Table 6 — WEM consumption

GWh	Budget 2015-16	Forecast 2015-16	Budget 2016-17	Estimate 2017-18	Estimate 2018-19
Load forecast	37,462	37,462	38,030 +2%	38,706 +2%	39,096 +1%
Loss Factor Adjusted Energy[1]	37,717	37,717	38,289	38,970	39,362

[1] The Loss Factor Adjusted (LFA) energy represents the transmission losses of electricity priced in the market fee rate.

Figure 6 – Annual WEM consumption



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CHAPTER 1. FEES AND TARIFFS

1.1 National Electricity Market (NEM)

The benchmark NEM fee will increase from $0.38/MWh to $0.39/MWh in 2016-17. This is in line with the estimate of $0.39/MWh provided to stakeholders in the 2015-16 budget process.

The 2016-17 fee of $0.39/MWh is due to:

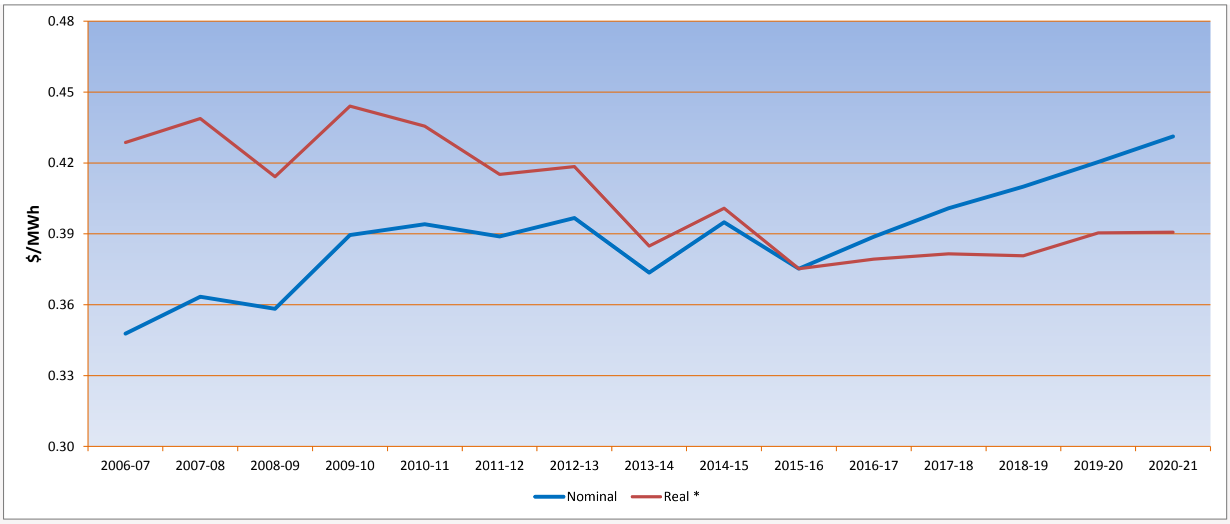
- 2016-17 budgeted costs increase by 3% compared to 2015-16 mainly related to an increased focus on the renewables program of works.
- Consumption forecast to increase by 1% in 2016-17 compared to the 2015-16 budget.

The Participant Compensation Fund (PCF) fee does not need to be charged in 2016-17 as the current level of NEM PCF funds being held meets the Rules requirement.

Table 7 — NEM projected fees (indicative benchmark)

Fee	Actual 2015-16	Budget 2016-17	Estimate 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21
NEM fee ($/MW·h)	0.38	0.39	0.40	0.41	0.42	0.43
	-5%	+4%	+3%	+2%	+3%	+3%

Figure 7 – NEM projected fees



* Real values are the nominal amounts adjusted for inflation. Prices have been calculated relative to the 2015-16 price.

1.2 Full Retail Contestability (FRC) Electricity

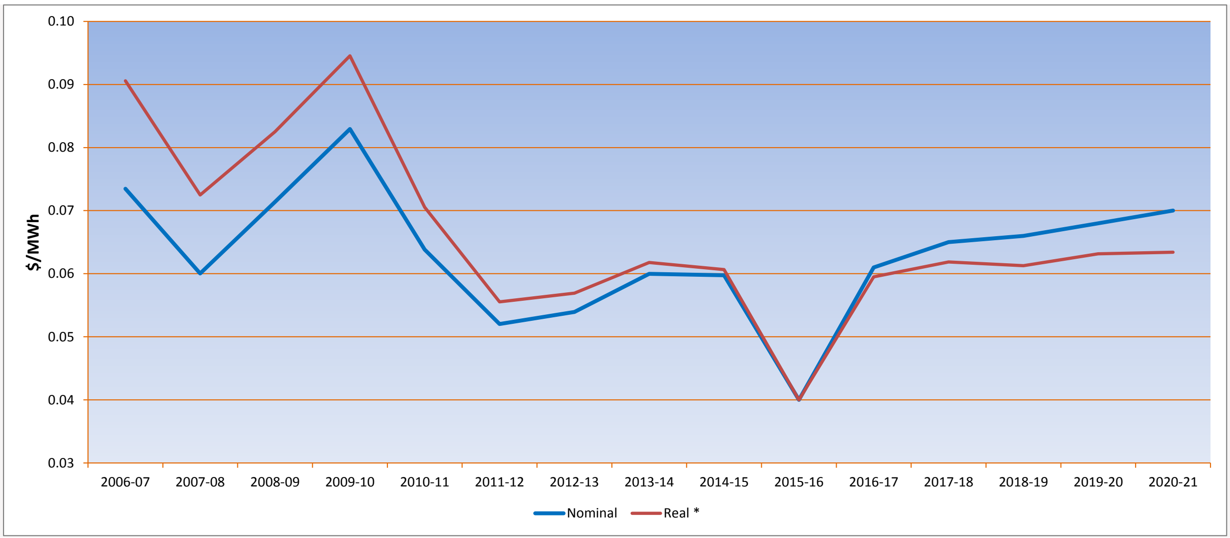
The FRC electricity fee will increase to $0.061/MWh mainly because the 2015-16 fee was lowered to return a surplus from the 2014-15 year.

This fee is 15% higher than the $0.053/MWh estimate provided to stakeholders as part of the 2015-16 budget process mainly due to higher costs associated with the Power of Choice program of work.

Table 8 — FRC Electricity Projected Fees (Indicative Benchmark)

Fee	Actual 2015-16	Budget 2016-17	Estimate 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21
($/MW·h)	0.040	0.061	0.065	0.066	0.068	0.070
	-33%	+53%	+7%	+2%	+3%	+3%

Figure 8 – FRC electricity projected fees



* Real values are the nominal amounts adjusted for inflation. Prices have been calculated relative to the 2015–16 price.

1.3 National Transmission Planner (NTP)

The NTP fee is budgeted to decrease from $0.02054/MWh to $0.01603/MWh in 2016-17.

This decrease is mainly due to the return of the 2015-16 surplus, higher consumption forecast and lower expenditure in 2016-17.

The 2016-17 fee is lower than the fee of $0.02421/MWh estimated as part of the 2015-16 budget process.

Costs in this function have decreased by $0.7M (17%) compared to the 2015-16 budget, mainly due to lower consulting costs and lower corporate costs (labour and depreciation).

Table 9 — National Transmission Planner Project Fees

Fee	Actual 2015-16	Budget 2016-17	Estimate 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21
($/MW·h)	0.02054	0.01606	0.02114	0.02164	0.02220	0.02279
	+3%	-22%	+32%	+2%	+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 mainly influenced by network charges billed by the Victorian electricity transmission network owners and by estimations of settlement residue receipts.

TUOS revenue is budgeted to decrease by $15.8M (3%) in 2016-17. This decrease in fees is primarily due to higher inter-regional TUOS receipts ($17.7M) which recover the costs of Victorian assets used to support inter-regional flows to neighbouring regions.

Table 10 — Projected TUOS Revenue Requirement

Fee	Actual 2015-16 ($'000)	Budget 2016-17 ($'000)	Estimate 2017-18 ($'000)	Estimate 2018-19 ($'000)	Estimate 2019-20 ($'000)	Estimate 2020-21 ($'000)
TUOS fees	512,354	496,548	512,385	TBC	TBC	TBC
	+2%	-3%	+3%			

1.5 Western Australia Wholesale Electricity Market (WEM)

The Western Australian Economic Regulation Authority (ERA) approves the Allowable Revenue and the Forecast Capital Expenditure that AEMO can recover from market participants in relation to the WEM.

AEMO is required to submit a proposal to the ERA by 16 September 2016 for the proposed Allowable Revenue and Forecast Expenditure for the WEM for the period 1 July 2016 to 30 June 2019. The planned timeline is that the ERA are required to make a determination on the proposal by 16 December 2016.

As a determination has not yet been made AEMO intends to continue to charge the 2015-16 WEM fee from 1 July 2016 until a determination is made by the ERA

Table 11 — WEM projected fees (Indicative benchmark)

Fee	Actual 2014-15 [1]	Actual 2015-16	Budget 2016-17	Estimate 2017-18	Estimate 2018-19
WEM fee ($/MW·h)	0.819	1.008	1.008	TBC	TBC
			+0%		

The fee listed above is a benchmark fee calculated by dividing the total cost of the WEM function by the total forecast consumption. The actual fee charged to both Market Customers and Generators is $0.504/MWh.

1.6 Declared Wholesale Gas Market (DWGM)

The DWGM Energy Tariff is budgeted to decrease 2% from $0.08806/GJ in 2015-16 to $0.08630/GJ in 2016-17. The 2016-17 fee is lower than the fee of $0.09422/GJ estimated as part of the 2015-16 budget process.

This decrease is mainly due to the return of the 2015-16 surplus and a higher consumption forecast and lower expenditure in 2016-17. Costs in this function have decreased by $0.6M (3%), mainly due to lower corporate costs (labour and depreciation).

Consumption growth is estimated to increase in 2016-17 due to higher Victorian exports to NSW and higher domestic consumption, offset by a small decrease in GPG. Industrial consumption is expected to decline from 2016-17.

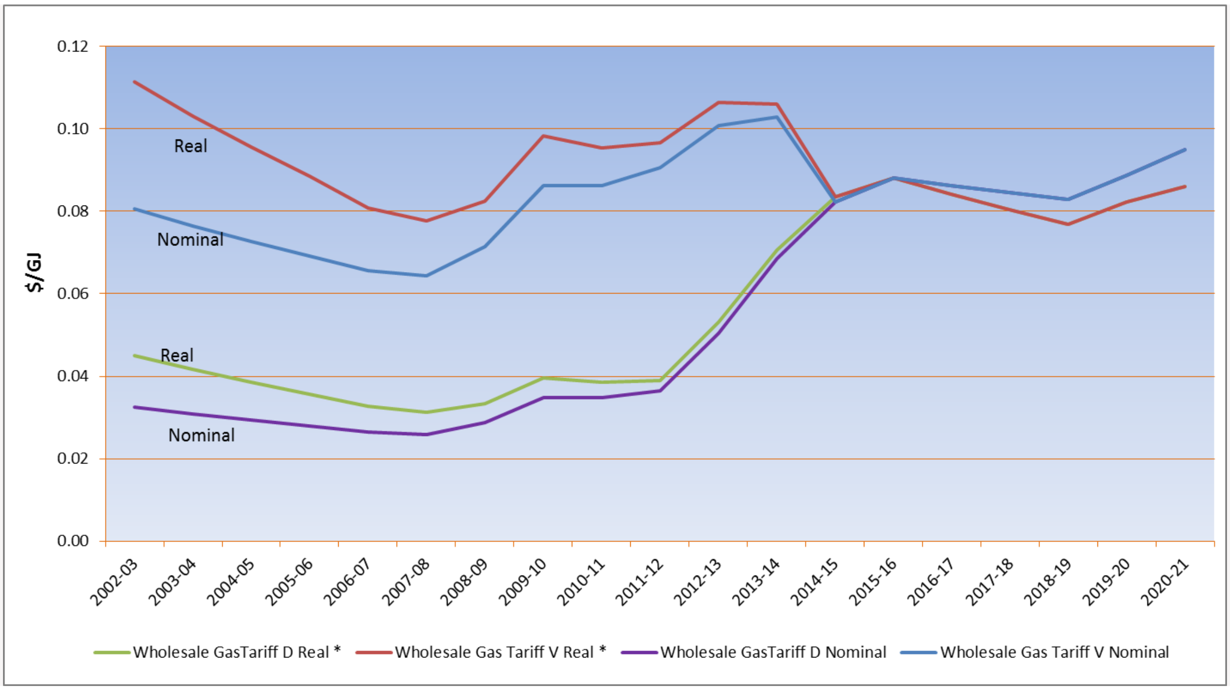
The distribution meter fee for 2016-17 relates to metering data services.

The Participant Compensation Fund (PCF) fee is not required to be charged in 2015-16 as the current level of DWGM PCF funds being held meet the Rules requirement.

Table 12 — Summary of DWGM Fees

Fee	Budget 2015-16	Budget 2016-17	Estimate 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21
Energy Tariff ($/GJ)	0.08806 +7%	0.08630 -2%	0.08457 -2%	0.08288 -2%	0.08868 +7%	0.09489 +7%
Distribution Meter ($/day per meter)	1.4208 -0%	1.37050 -8%	1.48780 +9%	1.5122 +2%	1.5454 +2%	1.5751 +2%
PCF Fee ($/GJ)	0	0	TBC	TBC	TBC	TBC

Figure 9 – Victorian Wholesale Gas Projected Fees



* Real values are the nominal amounts adjusted for inflation. Prices have been calculated relative to the 2015–16 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 by 3% from $0.08193/GJ to $0.07939/GJ in 2016-17. The 2016-17 fee is lower than the fee of $0.08067/GJ estimated as part of the 2015-16 budget process.

Costs for this function have decreased by $1.7M (18%), mainly due to fewer resources allocated to this function, lower interest as the STTM loan will be fully repaid, and lower depreciation.

The recovery of pipeline operator's Market Operator Services (MOS) costs also impact the STTM activity fee. AEMO is required to recover pipeline operator's MOS costs from STTM participants and pass these funds onto pipeline operators.

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.

Table 13 — Short Term Trading Market Projected Fees

Fee	Actual 2015-16	Budget 2016-17	Estimate 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21
Activity Fee ($/GJ withdrawn)	0.08193 +0%	0.07939 -3%	0.07708 -3%	0.07514 -3%	0.07964 +6%	0.08434 +6%
PCF Fee - Syd ($/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 2016-17 and by a further 15% in the following two years due to an accumulated surplus from prior years in the function.

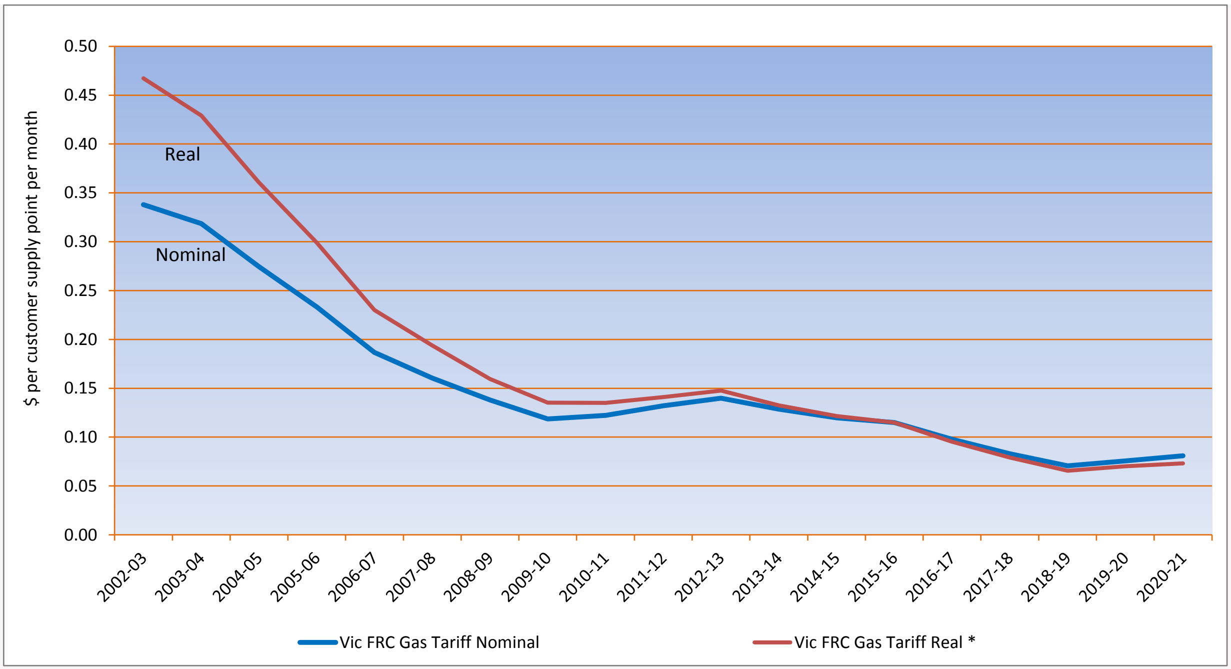
The fee is then expected to increase in the following years after the surplus is fully returned to achieve a break-even position.

Costs for this function have decreased by 34%, primarily due to fewer allocated labour resources.

Table 14 — Victorian FRC Gas Projected Fees

Fee	Actual 2015-16	Budget 2016-17	Estimate 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21
FRC Gas Tariff ($ per customer supply point per month)	0.11495 -4%	0.09771 -15%	0.08305 -15%	0.07059 -15%	0.07553 +7%	0.08082 +7%
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 2015–16 price.

1.9 Queensland FRC Gas

The Queensland FRC fee will reduce by 15% in 2016-17, and by a further 15% in the following two years due to an accumulated surplus from prior years in the function.

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

Costs for this function have decreased by 41%, primarily due to fewer allocated labour resources.

Table 15 — Queensland FRC Gas Projected Fees

Fee	Actual 2015-16	Budget 2016-17	Estimate 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21
FRC Fee ($ per customer supply point per month)	0.30805 +0%	0.26184 -15%	0.22256 -15%	0.18918 -15%	0.18918 +0%	0.18918 +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 11% in 2016-17, and by a further 11% in the following two years due to an accumulated surplus from prior years in the function.

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

Costs for this function have decreased by 16%, mainly due to fewer allocated labour resources.

Table 16 — South Australia FRC Gas Projected Fees

Fee	Actual 2015-16	Budget 2016-17	Estimate 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21
FRC Fee ($ per customer supply point per month)	0.29207 -5%	0.25994 -11%	0.23135 -11%	0.20590 -11%	0.21414 +4%	0.22271 +4%
Initial Registration Fee ($ per participant)	11300	11,300	TBC	TBC	TBC	TBC

1.11 NSW FRC Gas

A new market system which harmonised the NSW and ACT retail gas market systems with those operating in Victoria, Queensland and South Australia, went live on Monday 2 May 2016. As a result AEMO's services are now largely similar across all FRC gas markets.

The fee structure for the NSW/ACT Full Retails Contestability (FRC) gas function will change from 1 July 2016 in accordance with AEMO's Gas Market Fee Methodology published in March 2015. The methodology provided that from the financial year following the completion of the harmonisation project the fee would be based on a charge per customer supply point.

Costs for this function have increased due to the harmonisation project which has significantly increased depreciation costs in this function.

The NSW FRC fee has been set at $0.16750 per customer supply point, which generates a 50% increase in revenue from the 2015-16 budget. The revenue estimate is in line with the estimate in the 2015-16 budget process.

Table 17 — NSW FRC Gas Projected Fees

	Actual 2015-16	Budget 2016-17	Estimate 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21
FRC fee ($ per customer supply point per month)	0.11586 [1]	0.16750 +45%	0.17039 +2%	0.16319 -4%	0.15866 -3%	0.15935 +0%

[1] Indicative fee provided for comparison purposes only.

1.12 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 2016-17 fee is lower than the fee estimated as part of the 2015-16 budget process.

Table 18 — Gas Statement of Opportunities Projected Fees

Fee	Actual 2015-16	Budget 2016-17	Estimate 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21
Gas Statement of Opportunities ($ per customer supply point per month)	0.02830	0.03198 +13%	0.03614 +13%	0.04084 +13%	0.04247 +4%	0.04417 +4%

1.13 Gas Supply Hub

The gas supply hub voluntary market went live in March 2014.

The fees have been set at $0.03/GJ for day-ahead and on-the-day products, $0.02/GJ for the weekly products, and $0.01/GJ for the monthly products. This represents no change to 2015-16 fees.

Trade volumes are forecast to increase as a result of the Moomba hub expected to go-live in July 2016.

Table 19 — Gas Supply Hub Fees

Fee		Actual 2015-16	Budget 2016-17
Trading participants	Fixed Fee - one licence per annum	14,500	14,500
	Fixed Fee - additional licence per annum	5,500	5,500
	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	5,500

1.14 Gas Bulletin Board

Development work continued on the Gas Bulletin Board (GBB) in 2015-16, with introduction of a new Curtis Island zone to capture LNG information, interface improvements to support usability, and back-end improvements to improve storage and validation of GBB datasets.

On 17 December 2015, the AEMC also made a final Rule determination to improve information provided to the East Coast Gas Market via the GBB. Effective 6 October 2016, the new Rule will see a broader scope and resolution of data published for GBB production, transmission and storage facilities. AEMO is actively engaging with stakeholders to coordinate these changes.

These development projects, coupled with higher depreciation and IT hosting costs, have resulted in an increase in budgeted expenditure for the 2016-17 financial year. Forward year expenditure is estimated to reduce once GBB Rule Change project work is completed.

Table 20 — Gas Bulletin Board budget

Fee	Actual 2015-16 ($'000)	Budget 2016-17 ($'000)	Estimate 2017-18 ($'000)	Estimate 2018-19 ($'000)	Estimate 2019-20 ($'000)	Estimate 2020-21 ($'000)
Gas Bulletin Board	1,441	1,646 +14%	1,383 -16%	1,396 +1%	1,420 +2%	1,384 -3%

1.15 Western Australian Gas Services Information (GSI) fees

The ERA approves the Allowable Revenue and the Forecast Capital Expenditure that AEMO can recover from registered shippers and registered production facility operators in relation to the GSI.

AEMO is required to submit a proposal to the ERA by 16 September 2016 for the proposed Allowable Revenue and Forecast Expenditure for the GSI for the period 1 July 2016 to 30 June 2019. The planned timeline is that the ERA are required to make a determination on the proposal by 16 December 2016.

As a determination has not yet been made AEMO intends to continue to charge the 2015-16 GSI fee from 1 July 2016 until a determination is made by the ERA.

Table 21 — GSI projected fees

Fee	Actual 2015-16	Budget 2016-17	Estimate 2017-18	Estimate 2018-19
GSI fee ($'000)	1,834	1,834 +0%	TBC	TBC

1.16 Other Budgeted Revenue Requirements

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

Table 22 — Other Revenue Requirements

Key Fees	Actual 2015-16 ($'000)	Budget 2016-17 ($'000)
South Australia Planning	1,000	1,000
Settlement Residue Auctions	253	291

1.17 Energy Consumers Australia (ECA) fees

In May 2014 the Council of Australian Governments (COAG) Energy Council approved establishment of the Energy Consumers Australia (ECA) to absorb the functions of the existing Consumer Advocacy Panel (CAP) and promote the long term interests of energy consumers, in particular for residential customers and small business customers. AEMO is required to recover funding for the ECA from market participants.

The ECA was established on 30 January 2015.

The table 23 reflects the fees to be collected in electricity and gas for 2016-17.

Table 23 — Energy Consumers Australia (ECA) requirements

ECA Fees	Actual 2015-16	Budget 2016-17
Electricity ($ / connection point for small customers per week)	0.00976 +11%	0.00951 -3%
Gas ($ / customer supply point per month)	0.03114 +4%	0.03183 +2%

1.18 Western Australia System Management

From 1 July 2016, AEMO will assume responsibility for the System Management functions in Western Australia, which are currently performed by Western Power.

The System Management functions include the system operation services including all System Management functions and obligations under the Market Rules.

The ERA approves the Allowable Revenue and the Forecast Capital Expenditure that AEMO can recover from market participants in relation to System Management.

AEMO is required to submit a proposal to the ERA by 16 September 2016 for the proposed Allowable Revenue and Forecast Expenditure for the System Management for the period 1 July 2016 to 30 June 2019. The planned timeline is that the ERA are required to make a determination on the proposal by 16 December 2016.

As a determination has not yet been made AEMO intends to continue to charge the 2015-16 market fee from 1 July 2016 until a determination is made by the ERA.

The below table sets out the forecast nominal market fees.

	2015-16	2016-17	2017-18	2018-19
Market fee ($/MWh Nominal)	0.372	0.372	TBC	TBC

CHAPTER 2. AEMO FINANCIALS

2.1 Financials (excluding Systems Management)

Table 24 — Consolidated Profit and Loss 2016-17

Annual	AEMO (excl. Vic TNSP)				Victorian TNSP				AEMO (excl. WA functions)			
	Budget 2015-16 $'000	Forecast 2015-16 $'000	Budget 2016-17 $'000	Variance to Budget $'000	Budget 2015-16 $'000	Forecast 2015-16 $'000	Budget 2016-17 $'000	Variance to Budget $'000	Budget 2015-16 $'000	Forecast 2015-16 $'000	Budget 2016-17 $'000	Variance to Budget $'000
REVENUE												
Fees and Tariffs	121,398	122,623	127,195	5,796	-	-	-	-	121,398	122,623	127,195	5,796
TUoS Income	-	-	-	-	512,354	512,354	496,548	(15,806)	512,354	512,354	496,548	(15,806)
PCF Fees	-	-	-	-	-	-	-	-	-	-	-	-
Settlement Residue	-	-	-	-	28,693	25,080	26,594	(2,100)	28,693	25,080	26,594	(2,100)
Other Revenue	4,487	4,926	4,903	416	23,718	23,311	26,456	2,738	28,205	28,237	31,359	3,154
TOTAL REVENUE	**125,885**	**127,549**	**132,098**	**6,212**	**564,766**	**560,744**	**549,598**	**(15,167)**	**690,651**	**688,293**	**681,696**	**(8,955)**
NETWORK CHARGES	-	-	-	-	549,920	548,193	540,011	(9,909)	549,920	548,193	540,011	(9,909)
NET REVENUE	**125,885**	**127,549**	**132,098**	**6,212**	**14,845**	**12,551**	**9,587**	**(5,259)**	**140,731**	**140,100**	**141,685**	**954**
EXPENDITURE								-				-
Total Labour~	82,858	81,987	84,258	1,401	4,005	4,247	3,878	(126)	86,862	86,235	88,137	1,275
Contractors	351	1,444	1,197	845	-	-	-	-	351	1,444	1,197	845
Consulting	5,809	4,717	5,918	109	596	506	126	(470)	6,405	5,223	6,044	(361)
Fees-Agency, Licence and Audit	1,757	1,602	1,692	(65)	-	-	-	-	1,757	1,602	1,692	(65)
Information Technology and Telecommunication	16,557	15,440	16,975	418	0	0	5	5	16,558	15,440	16,980	423
Occupancy	5,158	5,200	5,475	317	-	-	-	-	5,158	5,200	5,475	317
Training & Recruitment	1,617	1,457	1,715	97	36	36	24	(12)	1,653	1,493	1,738	85
Travel & Accommodation	1,686	1,733	1,820	135	64	64	29	(35)	1,750	1,797	1,850	100
Other Expenses from Ordinary Activities	6,568	7,562	6,585	17	12	12	3	(9)	6,580	7,573	6,588	8
TOTAL OPERATING EXPENDITURE (excl Financing & Depreciation)	**122,361**	**121,142**	**125,635**	**3,273**	**4,712**	**4,864**	**4,066**	**(646)**	**127,073**	**126,007**	**129,701**	**2,627**
Depreciation and Amortisation	14,706	13,800	12,225	(2,481)	38	38	23	(15)	14,744	13,838	12,248	(2,496)
Financing Costs	1,705	1,705	1,456	(249)	-	-	-	-	1,705	1,705	1,456	(249)
Capitalised internal labour	(2,318)	(1,791)	(2,580)	(262)	(8)	-	(2)	6	(2,326)	(1,791)	(2,582)	(256)
TOTAL OPERATING EXPENDITURE	**136,454**	**134,856**	**136,736**	**282**	**4,741**	**4,902**	**4,086**	**(655)**	**141,196**	**139,758**	**140,823**	**(373)**
SURPLUS / (DEFICIT)	**(10,569)**	**(7,307)**	**(4,639)**	**5,931**	**10,104**	**7,649**	**5,501**	**(4,604)**	**(465)**	**342**	**862**	**1,327**
Transfer to Reserves / Recoveries	2,996	3,115	2,740	(256)	(3,554)	(3,673)	(3,262)	293	(558)	(558)	(522)	37
Brought Forward Surplus / (Deficit)	15,813	24,464	20,272	4,459	(6,077)	(6,213)	(2,237)	3,840	9,736	18,252	18,036	8,299
ACCUMULATED SURPLUS / (DEFICIT)	**8,240**	**20,272**	**18,373**	**10,134**	**474**	**(2,237)**	**2**	**(471)**	**8,713**	**18,036**	**18,376**	**9,663**
Contributed capital relating to Vic Wholesale gas market	(8,704)	(8,704)	(8,704)	-	-	-	-	-	(8,704)	(8,704)	(8,704)	-
ADJUSTED ACCUMULATED SURPLUS / (DEFICIT)	**(464)**	**11,569**	**9,670**	**10,134**	**474**	**(2,237)**	**2**	**(471)**	**9**	**9,332**	**9,672**	**9,663**

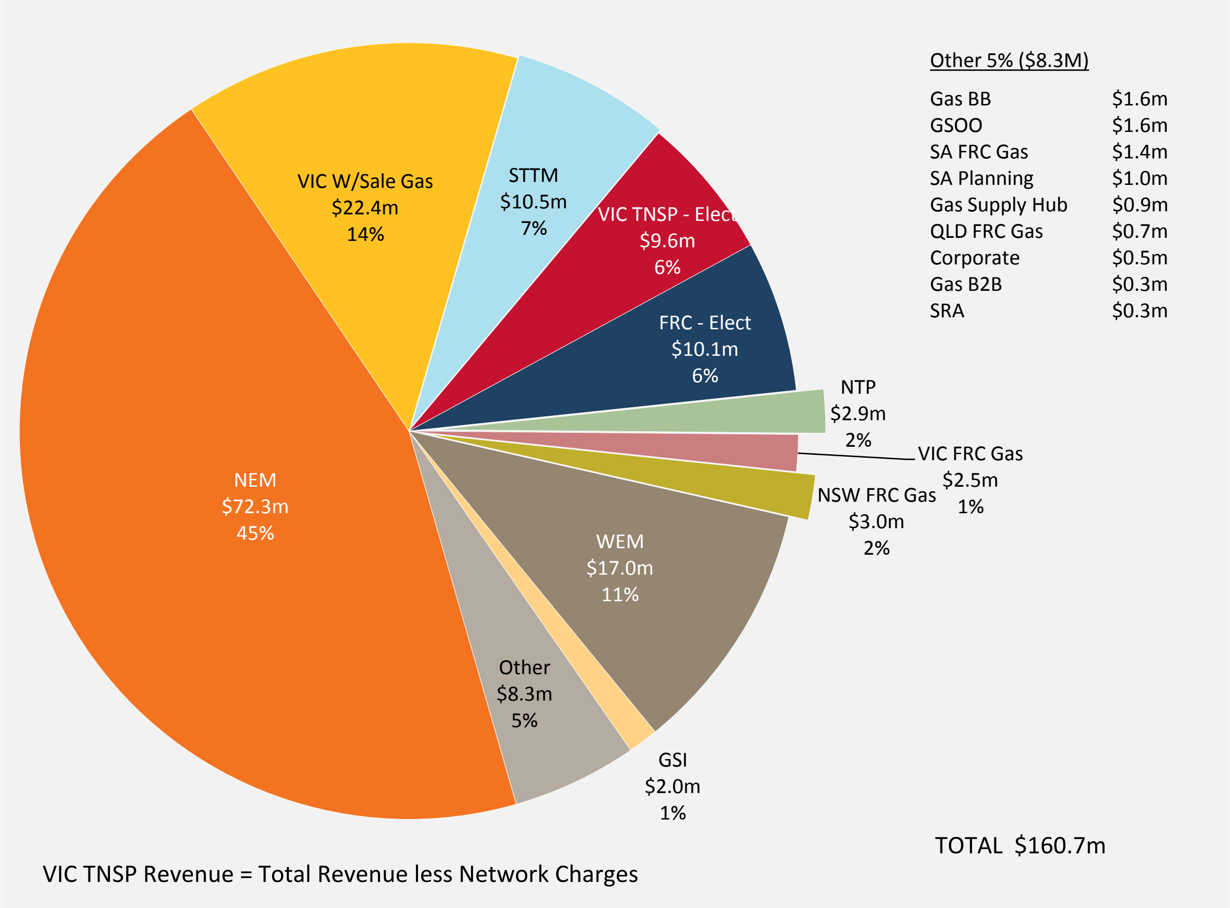
~ Total Labour includes both opex and capex labour.
Note the Budget 2016-17 accumulated surplus includes $8.7M of contributed capital relating to the Vic Wholesale Gas market.

Annual	AEMO (excl. WA functions)				WA functions				Total AEMO			
	Budget 2015-16 $'000	Forecast 2015-16 $'000	Budget 2016-17 $'000	Variance to Budget $'000	Budget 2015-16 $'000	Forecast 2015-16 $'000	Budget 2016-17 $'000	Variance to Budget $'000	Budget 2015-16 $'000	Forecast 2015-16 $'000	Budget 2016-17 $'000	Variance to Budget $'000
REVENUE												
Fees and Tariffs	121,398	122,623	127,195	5,796	19,849	19,927	18,933	(916)	141,248	142,550	146,128	4,880
TUoS Income	512,354	512,354	496,548	(15,806)	-	-	-	-	512,354	512,354	496,548	(15,806)
PCF Fees	-	-	-	-	-	-	-	-	-	-	-	-
Settlement Residue	28,693	25,080	26,594	(2,100)	-	-	-	-	28,693	25,080	26,594	(2,100)
Other Revenue	28,205	28,237	31,359	3,154	205	190	48	(157)	28,410	28,427	31,407	2,997
TOTAL REVENUE	**690,651**	**688,294**	**681,696**	**(8,955)**	**20,054**	**20,117**	**18,981**	**(1,073)**	**710,705**	**708,410**	**700,677**	**(10,028)**
NETWORK CHARGES	549,920	548,193	540,011	(9,909)	-	-	-	-	549,920	548,193	540,011	(9,909)
NET REVENUE	**140,731**	**140,101**	**141,685**	**954**	**20,054**	**20,117**	**18,981**	**(1,073)**	**160,785**	**160,217**	**160,666**	**(119)**
EXPENDITURE	-	-	-	-				-				-
Total Labour~	86,862	86,235	88,137	1,275	7,092	6,598	7,257	165	93,954	92,832	95,394	1,440
Contractors	351	1,444	1,197	845	205	214	81	(125)	557	1,658	1,277	721
Consulting	6,405	5,223	6,044	(361)	2,085	2,034	1,297	(788)	8,489	7,256	7,341	(1,148)
Fees-Agency, Licence and Audit	1,757	1,602	1,692	(65)	738	738	774	36	2,495	2,341	2,466	(29)
Information Technology and Telecommunication	16,558	15,440	16,980	423	2,291	2,957	2,411	120	18,849	18,397	19,391	543
Occupancy	5,158	5,200	5,475	317	812	811	857	45	5,970	6,011	6,331	362
Training & Recruitment	1,653	1,493	1,738	85	390	390	328	(62)	2,043	1,883	2,066	23
Travel & Accommodation	1,750	1,797	1,850	100	182	182	56	(126)	1,932	1,979	1,906	(26)
Other Expenses from Ordinary Activities	6,580	7,573	6,588	8	445	339	412	(33)	7,025	7,912	7,000	(25)
TOTAL OPERATING EXPENDITURE (excl Financing & Depreciation)	**127,073**	**126,007**	**129,701**	**2,627**	**14,240**	**14,263**	**13,473**	**(768)**	**141,313**	**140,270**	**143,174**	**1,860**
Depreciation and Amortisation	14,744	13,838	12,248	(2,496)	5,110	5,082	5,469	360	19,853	18,919	17,717	(2,136)
Financing Costs	1,705	1,705	1,456	(249)	423	405	441	19	2,127	2,109	1,897	(230)
Capitalised internal labour	(2,326)	(1,791)	(2,582)	(256)				-	(2,326)	(1,791)	(2,582)	(256)
TOTAL OPERATING EXPENDITURE	**141,196**	**139,759**	**140,823**	**(373)**	**19,772**	**19,749**	**19,383**	**(389)**	**160,968**	**159,508**	**160,206**	**(762)**
SURPLUS / (DEFICIT)	**(465)**	**342**	**862**	**1,327**	**282**	**368**	**(402)**	**(684)**	**(183)**	**710**	**459**	**643**
Transfer to Reserves / Recoveries	(558)	(558)	(522)	37	-	-	-	-	(558)	(558)	(522)	37
Brought Forward Surplus / (Deficit)	9,736	18,252	18,036	8,299	-	1,276	1,644	1,644	960	19,528	19,680	18,721
ACCUMULATED SURPLUS / (DEFICIT)	**8,713**	**18,036**	**18,376**	**9,663**	**282**	**1,644**	**1,242**	**960**	**219**	**19,680**	**19,617**	**19,400**
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**	**9,332**	**9,672**	**9,663**	**282**	**1,644**	**1,242**	**960**	**(8,485)**	**10,977**	**10,913**	**19,400**

~ Total Labour includes both opex and capex labour.
Note the Budget 2016-17 accumulated surplus includes $8.7M of contributed capital relating to the Vic Wholesale Gas market.

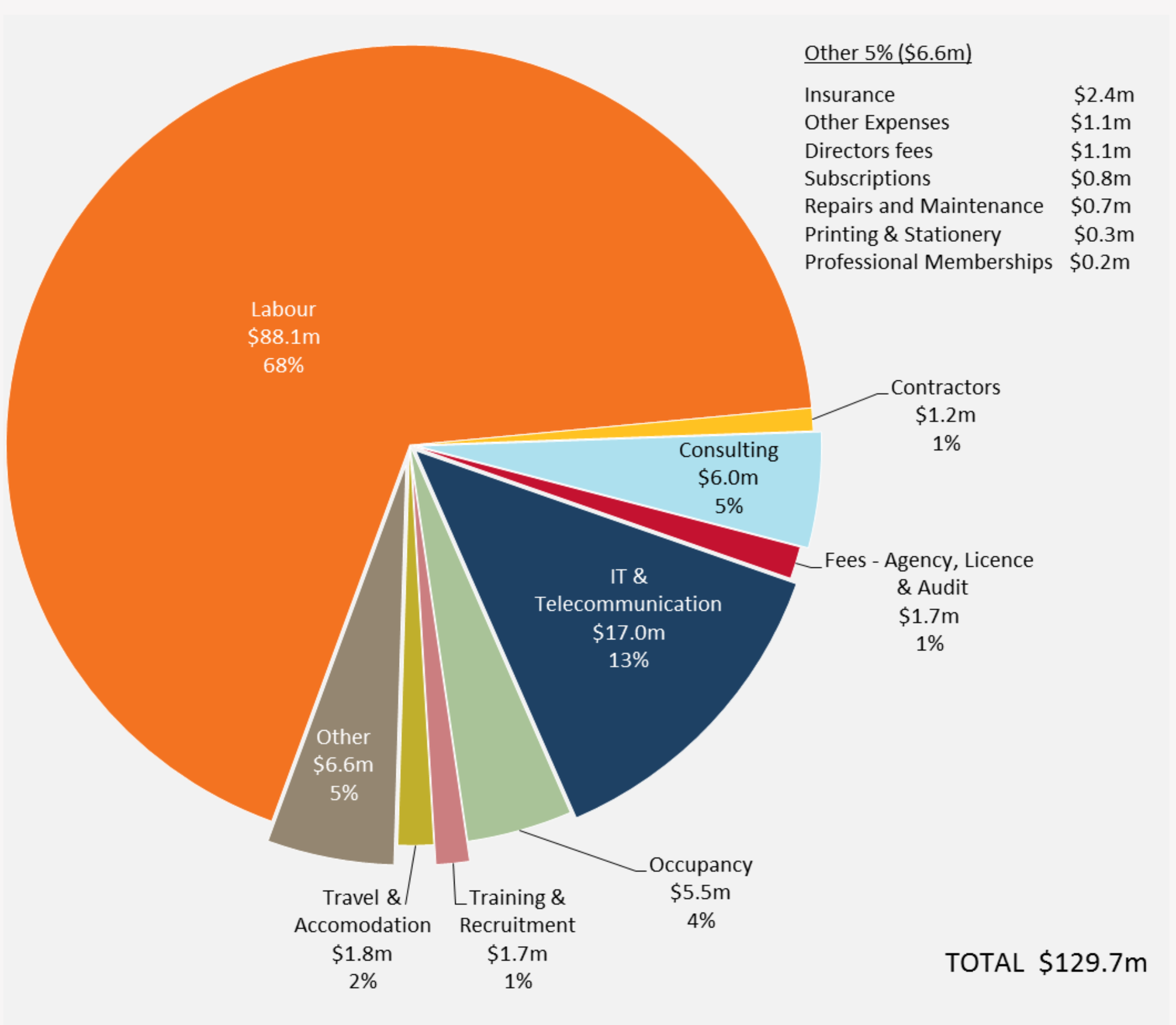
2.2 Net Revenue (excluding Systems Management)

Figure 11 – Net revenue by function



2.3 Expenditure (AEMO excluding WA functions)

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 $129.7M.

This is an increase of $2.6M (2%) from the 2015-16 budgeted expenditure.

Key points are:

- **Labour costs ($88.1M)**

  Labour costs are budgeted to increase by $1.3M (1%) compared with the 2015-16 budget.

  Key points and assumptions:

  – A provision has been made for Enterprise Bargaining Agreement (EBA) increases for employees and management of 2.9%, and a provision for the company performance score.

  – A vacancy allowance of 2.7% (2015-16: 2.7%) has been provisioned. The provision has the effect of reducing labour costs to allow for the time lag to fill vacant positions during the year.

  – Internal capitalised labour of $2.6M based on the capital expenditure projects in 2016-17 will be $0.3M (11%) higher than 2015-16 budget.

- **Contractor costs ($1.2M)**

  Contractor costs are budgeted to increase by $0.8M (241%) to $1.2M compared to 2015-16. Key costs for 2016-17 include:

  - Power of choice specialist support ($0.3M).
  - 16 vacation students ($0.2M).
  - Forecasting and modelling support ($0.2M).
  - New connection processing ($0.2M).
  - Legal support ($0.1M).

- **Consulting costs ($6.0M)**

  Consulting costs of $6.0M are budgeted to decrease by $0.4M (6%) compared to the 2015-16 budget.

  The major consulting items in the 2016-17 budget relate to:

  – Electricity forecasting and National Energy Forecast Report ($0.5M).
  – IT security testing ($0.4M).
  – Gas forecasting and National Gas Forecast Report ($0.4M).
  – Legal advice – including metering completion, connection and TNSP, employment and industrial advice, GSH development ($0.4M).
  – Asset and service management ($0.3M).
  – Counselling, remuneration benchmarking, employee development programs, HRMS development ($0.3M).
  – Electricity connection point forecasting ($0.2M).

- **Fees – agency licence and audit ($1.7M)**

  Agency, license and audit fees are budgeted to decrease by $0.1M (4%), mainly due to lower audit costs following the audit tender process in 2015-16.

- **IT and telecommunications ($17.0M)**

  – IT and telecommunication costs are budgeted to increase by $0.4M (3%) compared to the 2015-16 budget. This has been partly offset by a decrease in IT costs. In particular, there has been a decrease in IT costs through renegotiations of Optus and Telstra agreements for datalinks and market net and a reduction of in-house data centre costs for Mansfield. The saving have been reinvested in use of an external data centre provider based in Brisbane CBD to provide higher quality data centre services.
  – The reduction of depreciation costs relating to some IT systems will provide future opportunities and triggers to replace legacy IT technology.

- **Occupancy ($5.5M)**

  Occupancy costs are budgeted to increase by $0.3M (6%) compared to the 2015-16 budget, from a full year lease of the new Brisbane office and CPI increases for office leases.

- **Other expenses ($6.6M)**

  Other expenses are budgeted in line with the 2015-16 budget. The key items include insurance, director fees, repairs and maintenance and subscriptions and research data costs.

- **Financing costs ($1.5M)**

  Financing costs are budgeted to decrease by $0.3M (15%) compared to the 2015-16 budget mainly due to:

- Lower interest paid on STTM and Norwest loans as the principal outstanding reduces by $6M. The STTM loan is fully repaid in 2016-17.

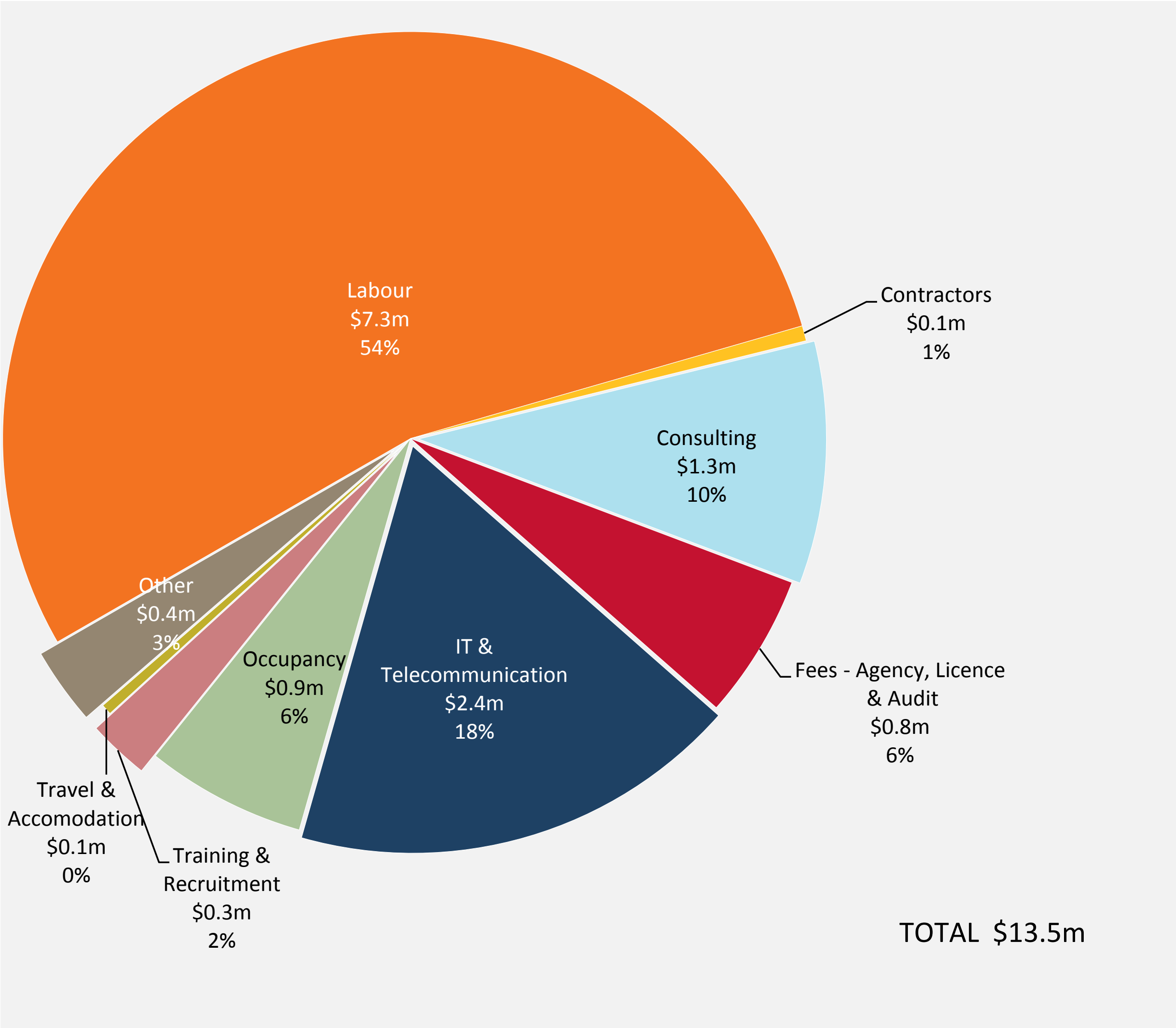
- **Depreciation costs ($12.2M)**

  Depreciation costs are budgeted to decrease by $2.5M (17%) compared to the 2015-16 budget mainly due to:

  - Declining depreciation costs in the major systems NEM, FRC Electricity, and STTM.
  - Reduction of depreciation costs as the demand forecast system, network equipment and other corporate systems are fully depreciated.

2.4 Expenditure (Western Australian functions)

Figure 13 – Total West Coast expenditure by category (excluding depreciation and finance costs)



2.4.1 Expenditure commentary

Total budgeted expenditure (excluding financing costs and depreciation) is $13.5M.

This is a decrease of $0.8M (5%) from the 2015-16 budgeted expenditure.

Key points are:

- **Labour costs**

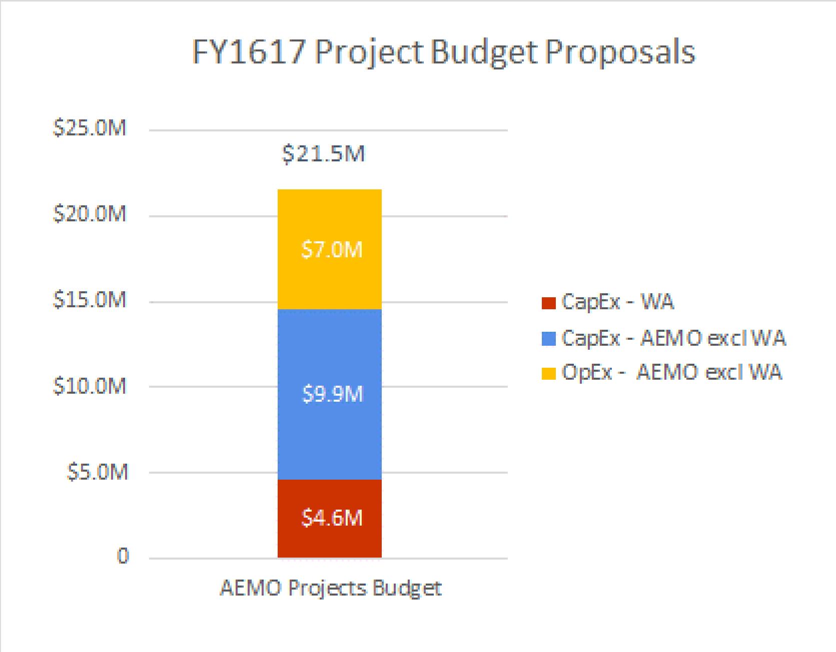
  Labour costs are budgeted to increase by $0.2M (2%) in 2016-17 compared to 2015-16, mainly due to a provision for the company performance score. These costs have been offset by lower resources required for the one off projects in 2015-16 to integrate systems management, the Electricity Market Review, and the AEMO transition.

- **Consulting**

  Consulting costs are budgeted to decrease by $0.8M (38%) in 2016-17 compared to 2015-16 mainly due to lower legal services costs which did not transition into AEMO and the Electricity Market Review costs required in 2015-16.

2.5 Project expenditure

The total project expenditure budgeted for 2016/17 is $21.5M.

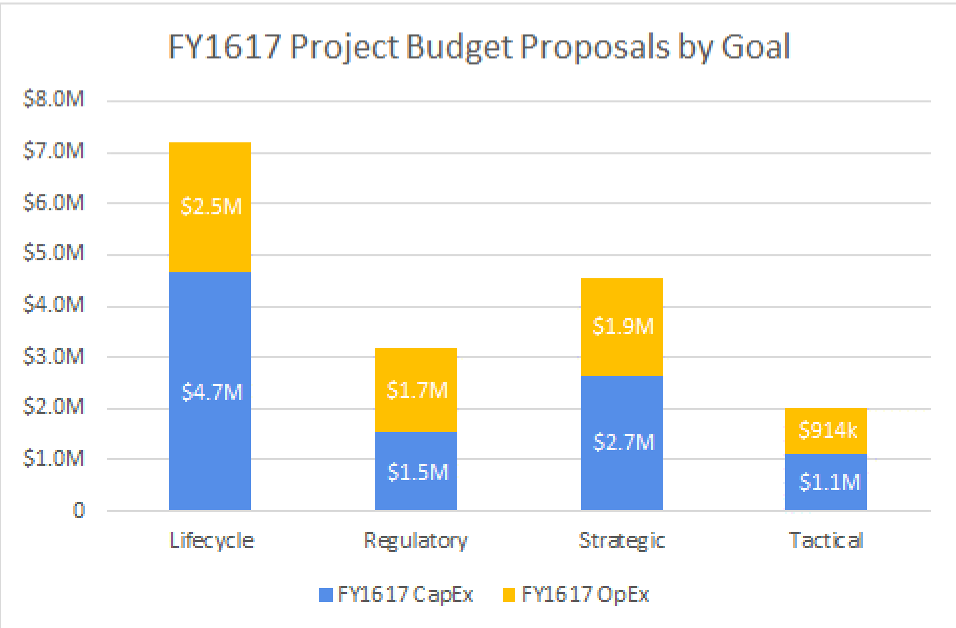


2.5.1 Project Expenditure (AEMO excluding WA functions)

High level costings

A total of $16.9M is budgeted for 2016/17.

Figure 14 – Project expenditure 2016-17



Lifecycle projects include:

- Energy Market Platform (EMP) upgrade ($2.4M)
- Market Clearing Engine (MCE) improvements ($1.1M)
- DWGM Platform Upgrade ($0.6M)

Regulatory projects include:

- Power of Choice Program ($2.2M)

Strategic projects include:

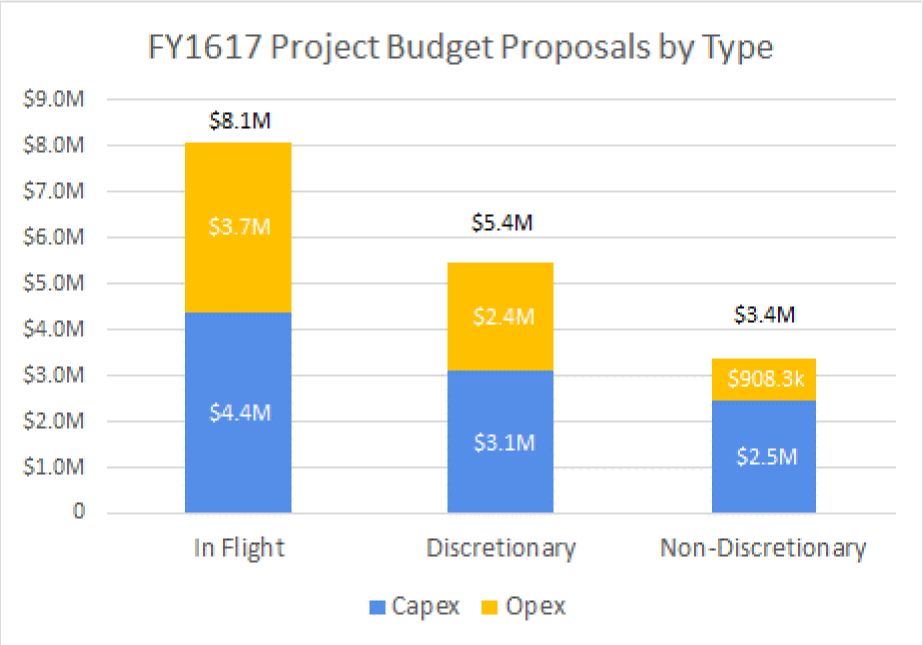
- Australian Solar Forecast System (ASEFS) stage 3 ($0.6M)
- Renewables Program Outputs ($0.5M)
- Data management platform ($0.8M)

Tactical projects include:

- Review 5 minute forecasting ($0.4M)
- Develop R-code for electricity and gas data streams ($0.3M)

Capital expenditure nature for 2016-17 (excluding WA functions)

Figure 15 – Capital expenditure nature



In Flight projects are existing projects from FY15-16.

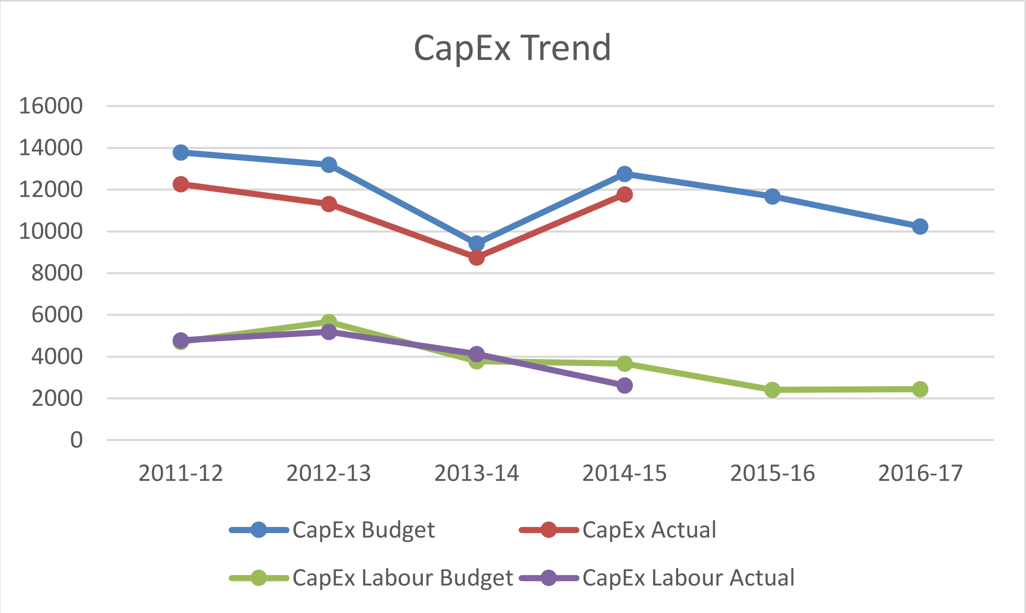
Figure 16 – Capital expenditure trend

	Financial Year 2016-17 project costs		
	Capital	**Operational**	**Total**
In-flight (existing projects from 2015-16)	$4.4M	$3.8M	$8.1M
Discretionary	$3.1M	$2.4M	$5.4M
Non-Discretionary	$2.5M	$0.9M	$3.4M
Total	**$9.9M**	**$7.0M**	**$16.9M**

Capital expenditure budget trend

There is a declining trend for total capital expenditure and flat trend for capital expenditure internal labour.

Figure 17 – Capital expenditure trend



Emerging work

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

- Northern Territory market reforms and service delivery.
- Integration of renewables and storage.
- New forecasting system.
- Shared Market Protocol, Meter Replacement Process.

2.5.2 Project expenditure (Western Australia functions)

High level costings

A total of $4.6M is budgeted for 2016-17. This amount was submitted for determination to the Energy Regulation Authority (ERA) in November 2015.

The projects budgeted for 2016-17 are:

Wholesale Electricity Market (WEMs) metering and settlement projects:

- Metering and settlement upgrades.
- Settlement technology refresh.
- Metering data management.

Gas Services information projects:

- GSI enhancements.

Corporate projects:

- Website upgrade.
- Corporate systems enhancements.
- End-user computing.
- Telephone replacement.

Other projects:

- Market transparency.
- Infrastructure market systems – data analysis, forecasting and modelling tools.
- WA AEMO office integration.

Emerging work

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

- Reserve Capacity Market changes.
- Electricity Market Review.
- System Management Transfer integration.

It is expected these will be presented for funding approval separately as and when they mature.

If they proceed a decision will be made as to whether they will displace budgeted projects or whether additional funds will be sought.

2.6 Balance Sheet 2016-17 (excluding Systems Management)

Table 25 — Balance Sheet 2016-17

	Forecast 2015-16 $'000	Budget 2016-17 $'000	Variance Budget 2016-17 to Forecast 2015-16 $'000	%
ASSETS				
Current Assets				
Cash and Short Term Deposits	23,132	24,740	(1,608)	-7%
Receivables	72,358	69,331	3,026	+5%
Other Current Assets	4,289	4,152	137	+3%
Total Current Assets	99,778	98,223	(1,555)	-2%
Non - Current Assets				
Intangible Assets - Software	31,376	29,710	1,667	+7%
Property, Plant and Equipment	29,553	28,029	1,524	+6%
Total Non Current Assets	60,929	57,739	(3,191)	-6%
TOTAL ASSETS	160,707	155,963	(4,744)	-3%
LIABILITIES				
Current Liabilities				
Payables	58,996	60,583	(1,587)	-3%
Borrowings	10,175	6,690	3,486	+186%
Provisions	19,497	19,857	(360)	-2%
Other Current Liabilities	5,368	5,368	-	+0%
Total Current Liabilities	94,037	92,498	(1,539)	-2%
Non - Current Liabilities				
Borrowings	19,973	18,258	1,715	+11%
Provisions	1,733	1,868	(135)	-10%
Lease Liability	5,324	3,240	2,084	+72%
Total Non Current Liabilities	27,030	23,366	(3,664)	-19%
TOTAL LIABILITIES	121,067	115,864	(5,203)	-5%
NET ASSETS / (LIABILITIES)	39,640	40,099	459	
EQUITY				
Capital contribution	7,093	7,093	-	+0%
Participant compensation fund reserve	10,601	10,896	(295)	-3%
Land reserve	2,266	2,493	(227)	-9%
Accumulated surplus/(deficit)	19,680	19,617	63	+0%
TOTAL EQUITY	39,640	40,099	459	

2.7 Cash Flow Statement 2016-17 (excluding Systems Management)

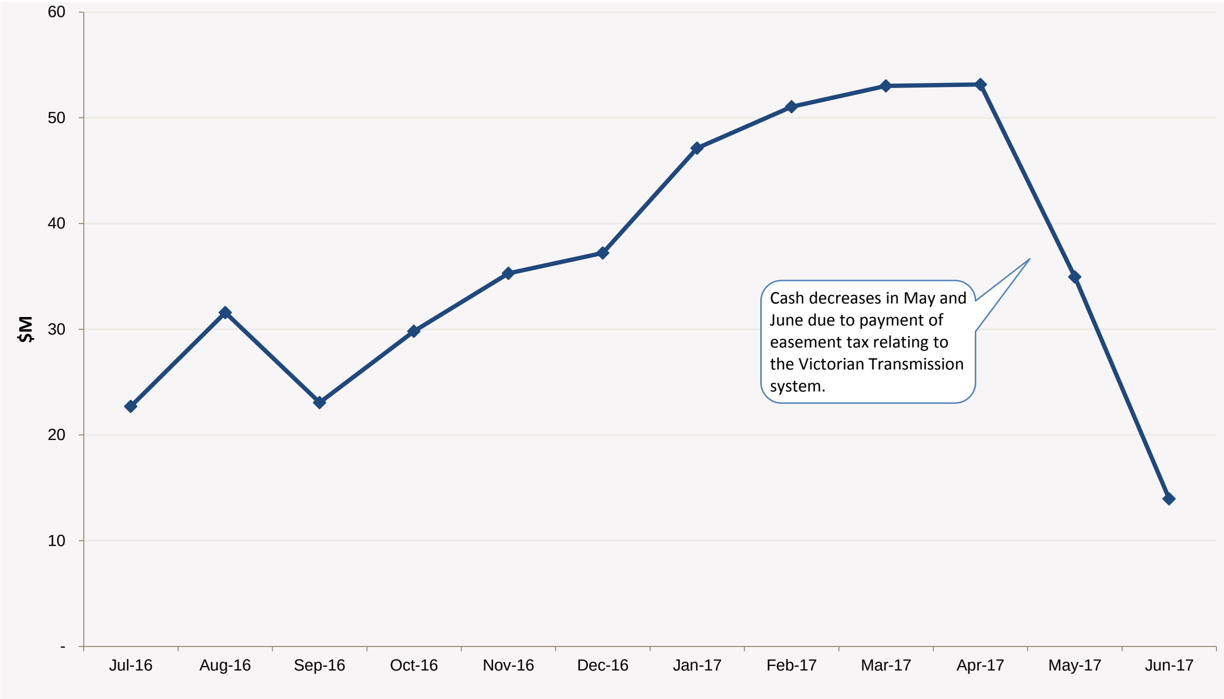
Table 26 — Cash Flow 2016-17

	Budget 2016-17 $'000
Cash flows from operating activities	
Receipts	
Receipts from customers (inclusive of GST)	772,833
Interest received	1,262
Total Receipts	**774,096**
Payments	
Payments to suppliers and employees (inclusive of GST)	(750,520)
Interest and other costs of finance paid	(1,626)
Total Payments	**(752,145)**
Net cash provided by operating activities	**21,950**
Cash flows from investing activities	
Payments for non-financial assets	(15,142)
Net cash used in investing activities	**(15,142)**
Cash flows from financing activities	
Proceeds from borrowings	-
Repayments of borrowings	(5,201)
Net cash used in financing activities	**(5,201)**
Net increase in cash held	**1,608**
Cash at the beginning of the period (including PCF) at 1 July 2016	23,132
Cash at the End of Period (including PCF) at 30 June 2017	**24,740**
Less: PCF Funds	(10,788)
Cash at the End of Period (excluding PCF) at 30 June 2017	**13,952**

The figure below reflects the monthly expected cash balance (excluding PCFs) for 2016-17.

Potential new borrowings for 2016-17 will include the Electricity Market Review project if approved.

Figure 18 – Expected closing cash balance (excluding PCF) for 2016-17



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. ELECTRICITY REVENUE AND FEE

Fee schedule for 2016-17 and forward years estimates

Function	Rate [1]					Basis	Paying Participants
	Budget 2016-17	Estimate 2017-18	Estimate 2018-19	Estimate 2019-20	Estimate 2020-21		
NEM							
General Fees (unallocated)	0.11663	0.12026	0.12300	0.12612	0.12937	MW·h of customer load	Market Customers
Allocated Fees							
- Market Customers	0.14695	0.15152	0.15498	0.15891	0.16300	MW·h of customer load	Market Customers
- Generators[2] and Market Network Service Providers	22,520	23,466	24,085	24,721	25,373	Daily rate calculated on capacity/ energy basis	Generators and Market Network Service Providers
Participant Compensation Fund	Nil	TBC	TBC	TBC	TBC	Daily rate calculated on capacity/ energy basis	Scheduled Generators, Semi-Scheduled Generators and Scheduled Network Service Providers
FRC ELECTRICITY							
FRC Operations	0.06100	0.06500	0.06600	0.06800	0.07000	MW·h of customer load in jurisdictions with FRC	Market Customers with a Retail Licence
Other							
National Transmission Planner	0.01606	0.02114	0.02164	0.02220	0.02279	MW·h of customer load	Market Customers
Electricity Consumer Advocacy Panel	0.00951	TBC	TBC	TBC	TBC	connection point for small customers/ week	Market Customers

[1] All fees and rates are exclusive of GST
[2] Excluding non market non scheduled generators

Fee schedule of new electricity registrations

Application Type	2016-17 $
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 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
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.