FINAL DECISION
Energex determination 2015−16 to 2019−20

Attachment 1 − Annual revenue requirement

October 2015

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Note

This attachment forms part of the AER's final decision on Energex's 2015–20 distribution determination. It should be read with all other parts of the final decision.

The final decision includes the following documents:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Value of imputation credits

Attachment 5 – Regulatory depreciation

Attachment 6 – Capital expenditure

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Attachment 11 – Service target performance incentive scheme

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Attachment 18 – Connection policy

Contents

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for electricity distribution
F&A	framework and approach
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators

Shortened form	Extended form
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

1 Annual revenue requirement

The annual revenue requirement (ARR) is the sum of the various building block costs for each year of the regulatory control period before smoothing. The ARRs are smoothed across the period to reduce fluctuations between years and to determine expected revenues for each year. The expected revenues are the amounts that Energex will target for annual pricing purposes and recover from customers for the provision of standard control services for each year of the regulatory control period. This attachment sets out our final decision on Energex's ARRs and expected revenues for the 2015–20 regulatory control period.

1.1 Final decision

We do not accept Energex's revised proposed total revenue requirement of $7739.3 million over the 2015–20 regulatory control period. This is because we have not accepted the building block costs in Energex's revised proposal. We determine a total revenue requirement (excluding additionals)[1] of $6557.0 million ($ nominal) for Energex for the 2015–20 regulatory control period, reflecting our final decision on the various building block costs. This is a reduction of $1182.3 million ($ nominal) or 15.3 per cent to Energex's revised proposal.

We approved in our preliminary decision the expected revenue for 2015–16 of $1139.8 million for Energex.[2] Under the transitional rules, we are required to determine the ARR for 2015–16 as part of this final decision process and do an adjustment for the difference between the preliminary decision revenue and the ARR for 2015–16. We have now determined the ARR for 2015–16 of $1415.8 million for Energex. The difference is therefore $276.0 million. We have applied this difference as part of the smoothing process to establish the annual expected revenue for the remaining four years of the 2015–20 regulatory control period.

As a result of our smoothing of the ARRs, our final decision on the annual expected revenue and X factor for each regulatory year of the 2015–20 regulatory control period is set out in table 1.1Table 1.1. Our final decision is to approve total expected revenues (excluding additionals) of $6599.9 million ($ nominal) for the 2015–20 regulatory control period.[3]

Figure 1.1 shows the difference between Energex's revised proposal and our decision (preliminary and final).

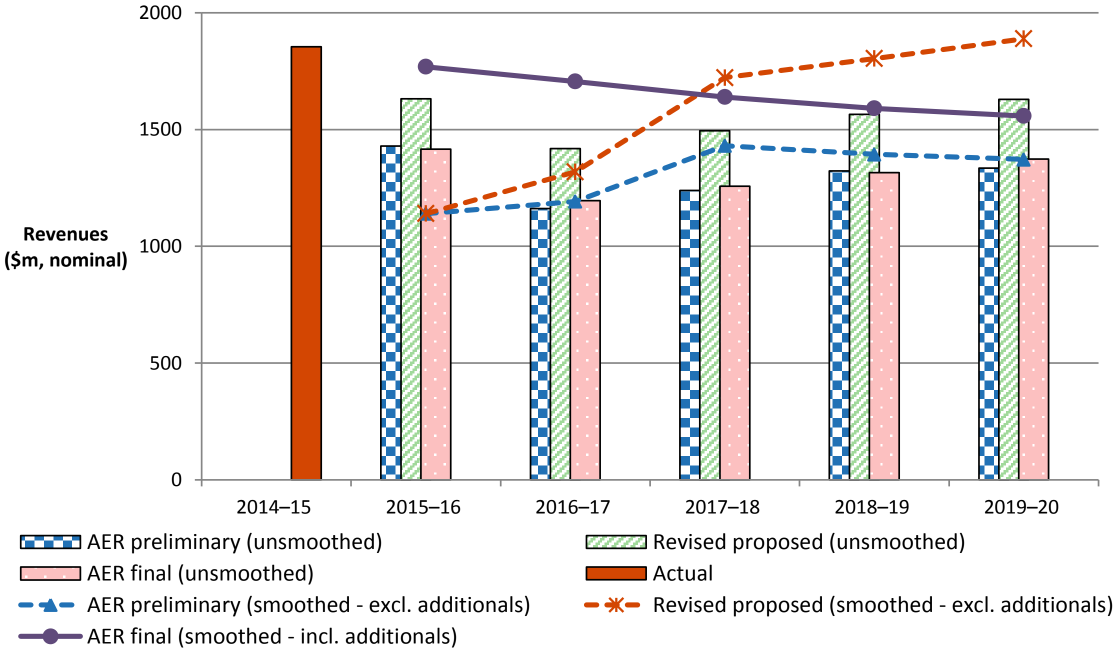
1 The additionals are amounts relating to other factors that will be recovered as part of DUoS but not within the building block revenue, such as the Solar Bonus Scheme feed-in tariff (FiT).

2 AER, *Preliminary decision, Energex determination 2015–16 to 2019–20 – Attachment 1 – Annual revenue requirement*, April 2015, p. 7.

3 Our smoothing involves a 'true-up' for the 2015–16 preliminary decision revenue as required under clause 11.60.4(e) of the NER.

Table 1.1 shows our final decision on the building block costs, the ARR, annual expected revenue and X factor for each year of the 2015–20 regulatory control period.

Figure 1.1 AER's final decision on Energex's revenues for the 2015–20 regulatory control period ($million, nominal)



Source: AER analysis. Energex, *Revised regulatory proposal*, July 2015, Attachment 2.

Table 1.1 AER's final decision on Energex's revenues for the 2015–20 regulatory control period ($million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Return on capital	671.2	701.6	732.3	760.0	788.2	3653.4
Regulatory depreciation	71.9	84.6	97.3	104.1	118.2	476.1
Operating expenditure	351.1	356.5	370.6	391.9	404.1	1874.1
Revenue adjustments[a]	273.6	1.1	1.1	1.1	1.1	278.0
Net tax allowance	48.0	52.2	55.5	57.8	61.8	275.3
Annual revenue requirement (unsmoothed)	1415.8	1196.1	1256.7	1315.0	1373.4	6557.0
Annual expected revenue (exc. additionals)	**1139.8**	**1189.2**	**1456.7**	**1418.4**	**1395.7**	**6559.9**
X factor[b]	n/a[d]	–1.79%	–19.50%	5.00%	4.00%	n/a
Additional amounts in DUoS[c]	628.6	512.4	182.1	172.0	162.0	1657.1
Annual expected revenue (smoothed – inc. additionals)	**1768.4**	**1701.6**	**1638.8**	**1590.4**	**1557.7**	**8257.0**
Annual change in revenue (inc. additionals)	n/a	–3.8%	–3.7%	–2.9%	–2.1%	n/a

Source: AER analysis.

(a) Revenue adjustments include forecast DMIA and DUoS under-recoveries.

(b) The X factors from 2016–17 to 2019–20 will be revised to reflect the annual return on debt update. Under the CPI–X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue.

(c) Additional amounts in DUoS include solar bonus scheme forecasts (jurisdictional scheme obligation for FiT) for 2015–20, estimated solar bonus scheme pass throughs for 2015–16 and 2016–17 relating to under-recoveries in 2013–14 and 2014–15, expected DUoS under-recovery in 2013–14 to be recovered in 2015–16, estimated transitional capital contribution pass throughs for 2015–16 and 2016–7 relating to under-recoveries in 2013–14 and 2014–15, STPIS rewards for 2015–16 and 2016–17, and DMIS allowance to be returned in 2016–17.

(d) In our preliminary decision, we determined the expected revenue and associated X factor for 2015–16. In this final decision to update the 2015–16 revenue for our assessment of efficient costs, we maintained the preliminary decision expected revenue and determined X factors for the final four years of the 2015–20 regulatory control period. This is to adjust Energex's total expected revenue requirement for the remaining four years in the 2015–20 regulatory control period for the difference between the preliminary decision revenue and our final decision on Energex's efficient costs for 2015–16.

1.2 Energex's revised proposal

Energex's revised proposal included a total expected revenue requirement (excluding addtionals) of $7873.5 million ($ nominal) for the 2015–20 regulatory control period.

Table 1.2 shows Energex's revised proposed building block costs, the ARR, expected revenue and X factor for each year of the 2015–20 regulatory control period.

Table 1.2 Energex's revised proposed revenues for the 2015–20 regulatory control period ($million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Return on capital	841.0	879.0	917.2	951.6	984.4	4573.1
Regulatory depreciation[a]	71.1	83.9	94.4	107.1	119.4	479.9
Operating expenditure	351.1	356.5	370.6	391.9	404.1	1874.1
Revenue adjustments[b]	273.6	–2.9	1.1	1.1	1.1	274.0
Net tax allowance	94.8	102.0	107.9	113.4	120.1	538.1
Annual revenue requirement (unsmoothed)	1631.5	1418.4	1495.2	1565.1	1629.1	7739.3
Annual expected revenue (exc. additionals)	**1139.8**[c]	**1318.7**	**1722.2**	**1804.1**	**1888.7**	**7873.5**
X factor	n/a	–12.88%	–27.41%	–2.20%	–2.13%	n/a
Additional amounts in DUoS	628.6	516.4	182.1	172.0	162.0	1661.1
Annual expected revenue (smoothed –inc. additionals)	**1768.4**	**1835.1**	**1904.3**	**1976.1**	**2050.6**	**9534.7**
Annual change in revenue (inc. additionals)	n/a	3.8%	3.8%	3.8%	3.8%	n/a

Source: Energex, *Revised regulatory proposal,* July 2015, p. 3; and Attachment 2.

(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening RAB.

(b) Revenue adjustments include proposed forecast DMIA, DMIA carry-over and DUoS under-recoveries.

(c) Energex's revised proposal conducted a true-up for the difference between the preliminary decision revenue and its revised proposal revenue for 2015–16 by holding the 2015–16 preliminary decision revenue constant. This results in the difference being adjusted for in the expected revenue (via the X factor) for the remaining four years of the 2015–20 regulatory control period.

1.3 AER's assessment approach

We have not changed our assessment approach for the ARR from our preliminary decision. Section 1.3 of our preliminary decision detailed that approach.[4] We have reviewed our revenue path for the final decision in light of the requirement to do an adjustment for 2015–16 and this is discussed further in section 1.4.1.

1.4 Reasons for final decision

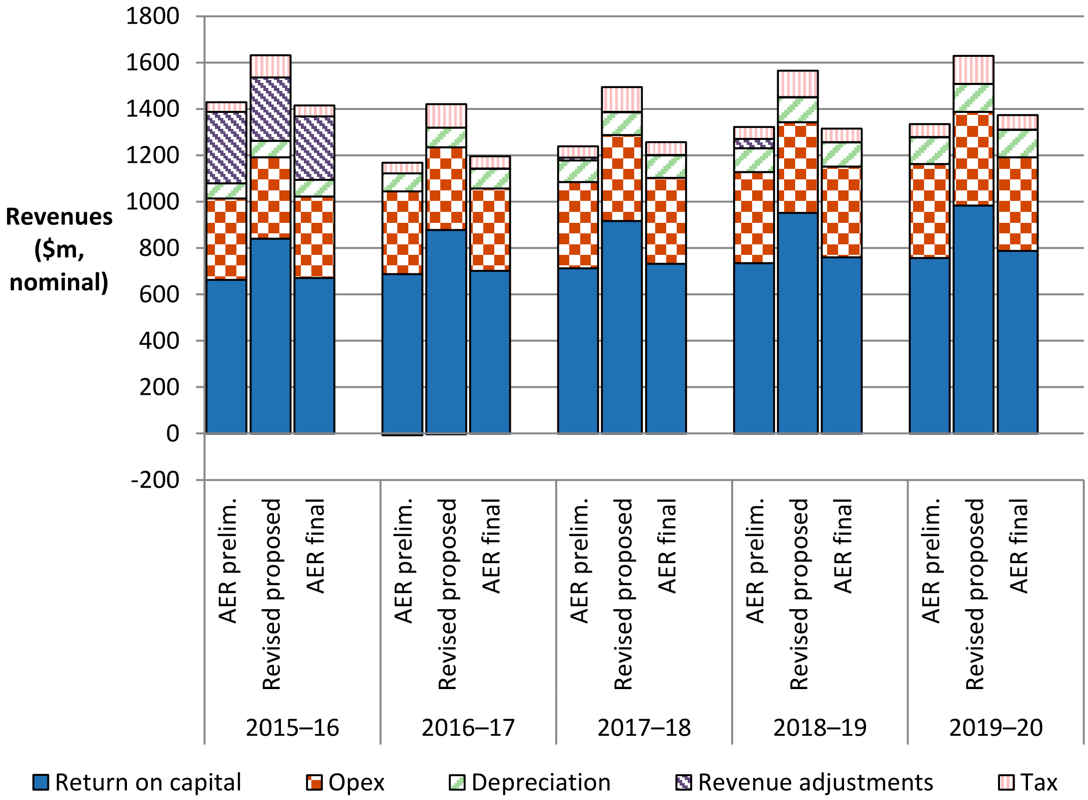
For this final decision, we determine a total revenue requirement of $6557.0 million ($ nominal) over the 2015–20 regulatory control period for Energex. This is $1182.3 million ($ nominal) or 15.3 per cent below Energex's revised proposal. This reflects the impact of our final decision on the various building block costs.

Figure 1.2 shows our preliminary decision and the difference between Energex's revised proposed ARRs and our final decision.

The most significant changes to Energex's revised proposal include a reduction in the return on capital allowance of 20.1 per cent (attachments 2 and 3) and a reduction in the capex allowance of 4.6 per cent (attachment 6).

4 AER, *Preliminary decision, Energex determination 2015–16 to 2019–20 – Attachment 1 – Annual revenue requirement*, April 2015, pp. 9–12.

Figure 1.2 AER's preliminary and final decisions and Energex's revised proposed annual revenue requirements ($million, nominal)



Source: AER analysis; Energex, *Revised regulatory proposal*, July 2015, Attachment 2.

1.4.1 Revenue true-up for 2015–16

In April 2015, as required under the transitional rules, we made our preliminary decision on Energex's proposed revenue requirement for the 2015–20 regulatory control period.[5] We determined the expected revenue for 2015–16 of $1139.8 million for Energex in the preliminary decision.[6]

For this final decision, we are required to revoke and substitute the preliminary decision for the ARRs over the 2015–20 regulatory control period. As part of this, we are to determine ARRs for each year of the 2015–20 regulatory control period and use a net present value (NPV) neutral adjustment mechanism to account for any difference between:[7]

- the expected revenue for 2015–16 approved in the preliminary decision, and

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5 NER, cl. 11.60.3.

6 AER, *Preliminary decision, Energex determination 2015–16 to 2019–20 – Attachment 1 – Annual revenue requirement*, April 2015, p. 7.

7 NER, cll. 11.60.4(d)(1) and (e).

- the ARR for 2015–16 that is established through this final determination process.

Our final decision approves the 2015–16 ARR of $1415.8 million for Energex. To give effect to the true-up, we have set Energex's first year expected revenue in the post-tax revenue model (PTRM) equal to our preliminary decision revenue for 2015–16 of $1139.8 million. This is the only practical option as prices were set for 2015–16 based on this approved preliminary decision amount. This approach means that the difference in the revenues for 2015–16 between the preliminary and final decisions is accounted for in the remaining four years of the 2015–20 regulatory control period. That is, the expected revenue for 2015–16 established from the preliminary decision provides a base from which the expected revenues (excluding additionals) for the remaining four years of the 2015–20 regulatory control period are calculated. This is done through the determination of the X factors for each of the remaining years in that period.[8] This gives effect to the true-up requirements under the NER and ensures that the difference of $276.0 million is returned to Energex over the remaining four years of the 2015–20 regulatory control period (adjusted for the time value of money).

Energex's revised proposal adopted this approach for the true-up.

1.4.2 Revenue smoothing

We have determined the smoothed revenue path having regard to major drivers of total network revenues (distribution use of system—DUoS—charges), which are elements that do not fit in the building blocks.[9] In particular, Energex has forecast large revenue recovery associated with the under-recovery of the solar bonus scheme (feed-in tariffs) in 2013–15. It has also forecast solar bonus scheme payments throughout the 2015–20 regulatory control period. In the determination for the 2010–15 regulatory control period, we included the forecast solar bonus scheme payments in the opex allowance. We included a pass-through mechanism for any difference to be applied two years later during the annual pricing proposal processes. As a result of this mechanism, the expected under-recoveries from 2013–14 and 2014–15 will be recovered in 2015–16 and 2016–17. Based on Energex's revised proposal, these amount to $254.6 million and $222.5 million ($ nominal) respectively. Then, in the 2015–20 regulatory control period, there is no solar bonus scheme forecasts included in the opex allowance. Instead, these amounts will be recovered through a jurisdictional scheme obligation, which will feed into DUoS as part of the annual pricing approval process.

Other annual revenue adjustments are also significant. In particular, Energex expects to under-recover its 2013–14 DUoS target by $111.0 million, which will be recovered in 2015–16. It also expects to seek pass throughs for under-recovered capital

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8 The X factors represent the rate of change in the real revenue path over the 2015–20 regulatory control period under the CPI–X framework. They must equalise (in net present value terms) the total expected revenues to be earned by the service provider with the total revenue requirement for that period.

9 AER, *Preliminary decision, Energex determination 2015–16 to 2019–20 – Attachment 1 – Annual revenue requirement*, April 2015, Table 1.3.

contributions in 2013–14 ($47.3 million) and 2014–15 ($37.2 million), which will be recovered in 2015–16 and 2016–17 respectively.

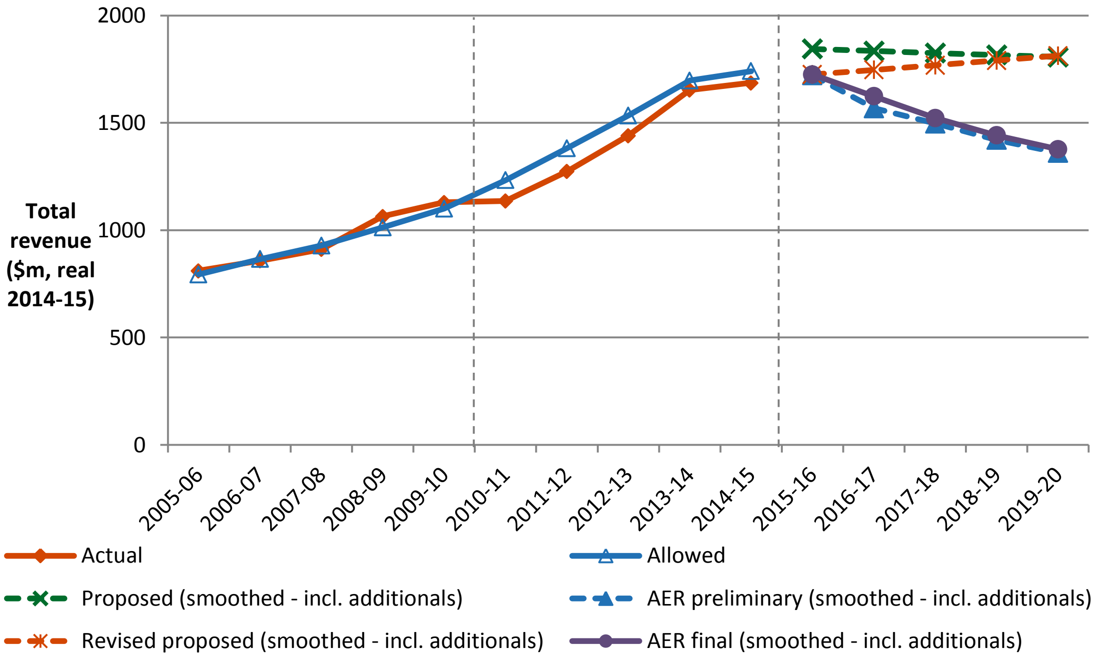
Accordingly, we have smoothed the building block revenue for standard control services over the 2015–20 regulatory control period by taking account of these additional forecast revenue impacts. This is consistent with the approach proposed by Energex and which we adopted in the preliminary decision. Overall, we are satisfied this will contribute to a smoother final revenue path for customers and the service provider.

In practice, we would normally set the path of X factors to result in a smooth expected revenue path. That is, these X factors would result in the desired smoothed path of the annual expected revenues through the regulatory control period. However, due to the sizeable factors outside of the building blocks that will affect total DUoS revenue, we have adopted a different approach outlined above. Specifically, when determining the X factors that set the path for smoothed expected revenue, we have considered the additional impact of these additional factors. As a result, the smoothed expected revenue does not produce a desirable path for revenue in isolation. However, the total DUoS revenue to be faced by customers including the additional factors will be smoothed overall. Further, we note that our profile of X factors results in an expected revenue in the last year of the regulatory control period that is as close as reasonably possible to the ARR for that year.[10]

Figure 1.3 shows the revenue path of our final decision smoothed revenues including additional revenue amounts. This is the expected revenue path that includes additional amounts that Energex is able to recover from network customers. Figure 1.4 shows the expected revenues excluding the additional amounts. Neither Energex nor the AER are able to influence these additional revenues going forward as they emerge from either separate Government schemes or in truing up outcomes from previous years.

[10] In the present circumstances, based on the X factors we have determined for Energex, this divergence is around 1.6 per cent.

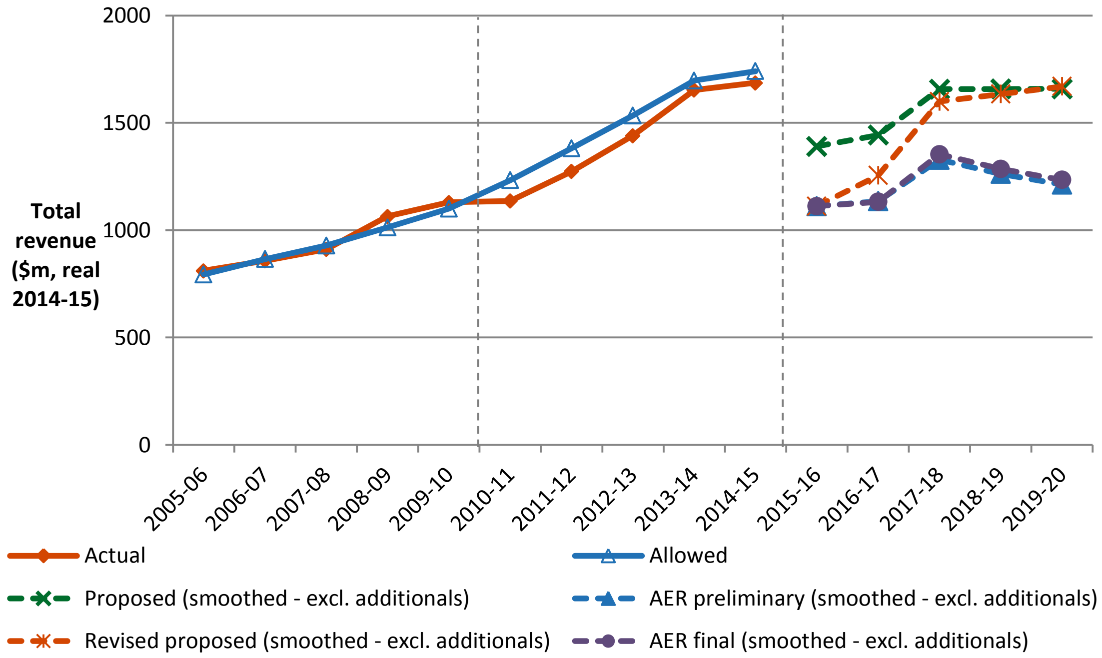
Figure 1.3 Smoothed revenue path including additional amounts ($ million, 2014–15)



Source: AER analysis.

Note: 'Additionals' in DUoS include solar bonus scheme forecasts (jurisdictional scheme obligation for FiT) for 2015–20, estimated solar bonus scheme pass throughs for 2015–16 and 2016–17 relating to under-recoveries in 2013–14 and 2014–15, expected DUoS under recovery in 2013–14 to be recovered in 2015–16, estimated transitional capital contributions pass throughs for 2015–16 and 2016–17 relating to under-recoveries in 2013–14 and 2014–15, STPIS rewards to be recovered in 2015–16 and 2016–17, and DMIS allowance to be returned in 2016–17. The 'Allowed' 2014–15 data point is the amount allowed in the AER final decision excluding additionals. The 'Actual' 2014–15 data point is an updated forecast of the amount Energex actually expects to recover, including additionals, as submitted in its reset RIN.

Figure 1.4 Smoothed revenue path excluding additional amounts ($ million, 2014–15)



Source: AER analysis.

In its submission to the preliminary decision, the Alliance of Energy Consumers stated that we should identify the additional revenues Energex is expected to receive over the remaining years of the regulatory control period.[11] We have done so above and in the final decision PTRM, although we note that these amounts are in some cases estimates and the actual outcomes may differ somewhat. The annual pricing proposals of the distributors—that are approved by us and then released on our website—explain in detail the actual outcomes in relation to these annual adjustments to revenues. These pricing proposals also show the evolution of the distributor's unders and overs account. That is, whether prices and demand were such that the distributor achieved its revenue targets in previous years and what further true-ups for past under or over recoveries may be necessary.

1.4.3 Revenue increments or decrements

Revenue increments or decrements arising from the operation of a control mechanism or scheme, also known as 'carry-overs', may have a sizeable impact in addition to our approved ARRs for the 2015–20 regulatory control period.[12] The revenue increment and decrement amounts are shown in table 1.3.

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[11] Alliance of Energy Consumers, *Submission to the AER's preliminary decision (Queensland)*, 3 July 2015, p. 32.

[12] NER, cll. 6.4.3(a)(5), (6), (6A).

Table 1.3 Revenue increments or decrements ($million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Closing balance of DUoS unders and overs account as at 30 June 2015.	272.6	0.0	0.0	0.0	0.0	272.6
DMIA	1.0	1.1[a]	1.1	1.1	1.1	5.4
Total	**273.6**	**1.1**	**1.1**	**1.1**	**1.1**	**278.0**

Source: AER analysis.

(a) Energex's revised proposal included the impact of expected DMIA carry-over from the 2010–15 regulatory control in its building blocks. The carry-over amount is to be accounted for in the annual pricing approval process for 2016–17 and therefore is not provided for in the building block assessment for this final decision. Instead, it is included in the 'additional' amounts as part of overall revenue smoothing.

This section explains how these revenue increments or decrements arose.

Over the 2010–15 regulatory control period, we regulated Energex under a revenue cap form of control. Under this form of control, service providers recover no more or less than the total allowed revenue, which usually includes:

- Building block expected revenue set in the determination.
- Under or over-recovery in the expected revenue from two years prior—these amounts are for two years prior because the full amount of any under/over-recovery is not known until the end of a pricing year, but the pricing approval process must take place in advance of the pricing year. Therefore, there is a two-year lag between when the pricing year finishes and when revenue under/over-recoveries can be included in the future revenue target.
- Any change in the balance of the unders and overs account. A balance may emerge in the unders and overs account where an under or over-recovery from an earlier year has not been fully recovered two years later. The residual then needs to be recovered in subsequent years. We generally target a zero balance for the unders and overs account, but in Queensland circumstances prevented this as discussed below.
- Jurisdictional scheme obligation amounts—these are amounts that the service provider is required to collect under legislation and which we are not required to assess.
- Pass through amounts—these are amounts that the service provider has applied for under the pass through provisions in its determination and we have subsequently approved. Often, this relates to events with unforeseeable likelihood and or timing, such as damage due to storms or regulatory changes.
- Other factors—this category includes applicable incentive scheme amounts, such as the S-factor for STPIS.

Energex has accumulated a large under-recovery balance in its unders and overs account due to:

- revenue cap under-recoveries
- pass through of feed-in tariffs under-recoveries.

These are amounts that Energex was allowed to recover as revenues over the 2010–15 regulatory control period, but did not do so. In particular, these amounts accumulated due to three main factors:

- Throughout the 2010–15 regulatory control period, consumption of electricity on Energex's network decreased at a faster rate than was projected in pricing forecasts. Approved prices are set annually to recover the target revenue based on estimated units of consumption, customer numbers and other factors where relevant. Holding all else constant, if any of these units is overestimated:
    - prices are relatively lower than they should have been, since the same revenue amount is shared across a larger number of units
    - revenue is therefore lower than it should have been, since it is the product of a lower-than-forecast actual number of units multiplied by a relatively lower price.
- Uptake of the solar bonus scheme (feed-in tariffs) was greater than forecast. Annual estimates of the feed-in tariffs were included in Energex's opex allowance over the 2010–15 regulatory control period. However, since this was a new jurisdictional policy and hence difficult to forecast, we approved a specific unders/overs factor to account for the difference between forecast and actual. As the take-up of the scheme was much greater than forecast, this led to a large under-recovery balance.
- These in combination led to a triggering of the under-recovery threshold. In the 2010 determination, we set a 5 per cent unders/overs threshold for accumulated under or over-recovery balances. On meeting this threshold, Energex submitted a plan to clear the balance over several years, rather than in a single or two years[13]. Part of this plan included the recovery of some of the revenue in the 2015–20 regulatory control period. This was designed to prevent larger increase in prices during the 2010–15 regulatory control period.

Shared assets

In the preliminary decision, we considered that Energex's forecast shared asset unregulated revenues do not meet the minimum threshold for adjustments to be made to its ARR.[14] We continue to maintain this view. Our final decision is therefore consistent with our preliminary decision.

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[13] Balances of the unders and overs account of less than 2 per cent were to be recovered in one year, while balances between 2 to 5 per cent were to be recovered over two years.

[14] AER, *Preliminary decision, Energex determination 2015–16 to 2019–20 – Attachment 1 – Annual revenue requirement*, April 2015, pp. 16–17.

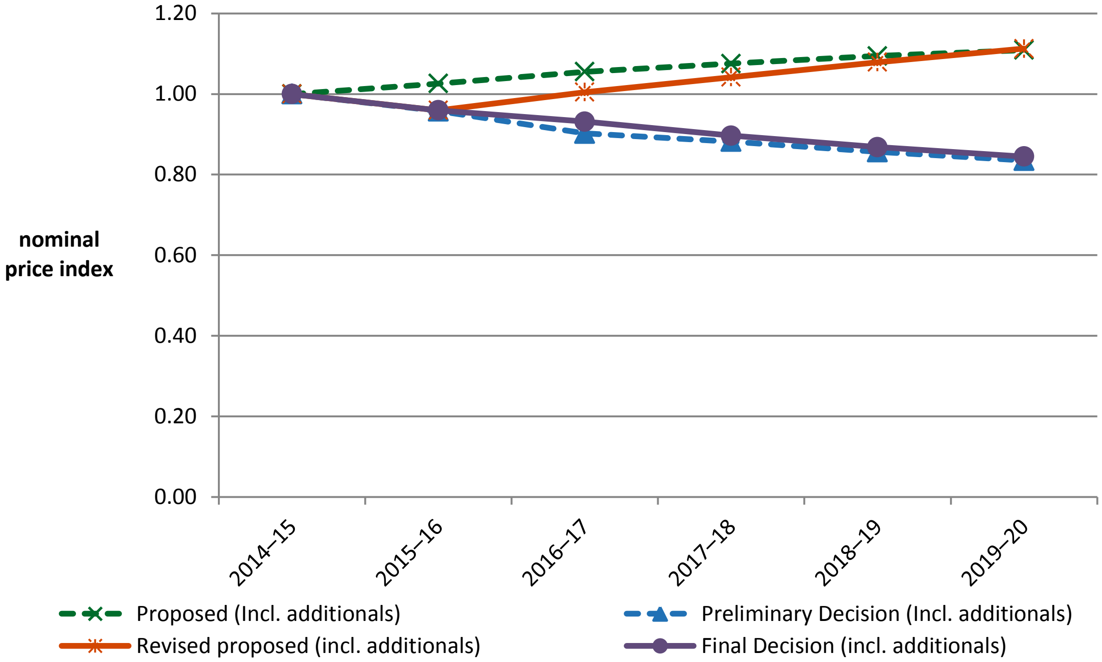
1.4.4 Indicative average distribution price impact

Our final decision on Energex's expected revenues ultimately affects the prices consumers pay for electricity. There are several steps required in translating our revenue decision to a price impact.

We regulate Energex's standard control services under a revenue cap form of control. This means our final decision on Energex's expected revenues do not directly translate to price impacts. This is because Energex's revenue is fixed under the revenue cap form of control, so changes in the consumption of electricity will affect the prices ultimately charged to consumers. We are not required to establish the distribution prices for Energex as part of this determination. However, we will assess Energex's annual pricing proposals before the commencement of each regulatory year for the 2015–20 regulatory control period to administer the pricing requirements in this distribution determination.

For this final decision, we have estimated some indicative average distribution price impacts flowing from our determination on the expected revenues and jurisdictional scheme obligation amounts for Energex over the 2015–20 regulatory control period. Figure 1.5 shows Energex's indicative price path based on the expected revenues established in our final decision compared to its revised proposal. We used the data on average price changes Energex provided in its initial and revised proposals. We estimated average prices by dividing expected revenue by the total forecast energy consumption (MWh) in Energex's distribution network to determine the movement in overall prices. For presentational purposes, the prices are scaled so that the price index begins at 1.0 in 2014–15. The index provides a simple overall measure of the relative movement in expected distribution prices over the 2015–20 regulatory control period.

Figure 1.5 AER's final decision and Energex's revised proposed indicative price paths (nominal price index)



Source: AER analysis.

Notes: The nominal price index is calculated by the AER based on the indicative average price changes submitted by Energex in its initial and revised proposal, and adjusting for the change in overall revenue substituted by the AER.

We estimate that our final decision on Energex's annual expected revenue (including additionals) will result in a decrease to average distribution charges by about 3.3 per cent per annum over the 2015–20 regulatory control period in nominal terms. This compares to the nominal average increase of approximately 2.2 per cent per annum proposed by Energex over the 2015–20 regulatory control period. This amount includes a forecast inflation rate of 2.5 per cent per annum. In real terms we estimate average distribution charges to decline by 5.7 per cent per annum, compared to a decline of 0.3 per cent proposed by Energex.

Table 1.4 displays the comparison of the price impacts of Energex's revised proposal and our final decision revenue allowance.

Table 1.4 Comparison of revenue and price impacts of Energex's revised proposal and the AER's final decision

	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20
AER final decision						
Revenue ($m, nominal) [a]	1854	1768	1702	1639	1590	1558
Price path (nominal index)	1.00	0.96	0.93	0.90	0.87	0.84
Revenue (change %)		–4.6%	–3.8%	–3.7%	–2.9%	–2.1%
Price path (change %)		–4.1%	–2.9%	–3.7%	–3.2%	–2.7%
Energex revised proposal						
Revenue ($m, nominal)[a]	1854	1768	1835	1904	1976	2051
Price path (nominal index)	1.00	0.96	1.00	1.04	1.08	1.11
Revenue (change %)		–4.6%	3.8%	3.8%	3.8%	3.8%
Price path (change %)		–4.1%	4.7%	3.7%	3.5%	3.1%

Source: AER analysis.

(a) This includes the additional amounts in DUoS that are not in the building block revenue allowance.

Distribution charges represent approximately 42 per cent on average of Energex's typical customer's annual electricity bill.[15] We expect that our final decision, holding all other components of the bill constant, will reduce the average annual electricity bills for residential customers in Energex's network. This is because we estimate that our final decision will result in lower distribution charges on average over the 2015–20 regulatory control period compared to Energex's revised proposal as discussed above. We estimate that based on the distribution charges from our final decision passing through to customers, we would expect the average annual electricity bill for residential customers to reduce by $25 or 1.7 per cent in 2015–16. This would be followed by decreases of about $18 or 1.2 per cent ($ nominal) per annum from 2016–17 to 2019–20. By comparison, had we accepted Energex's revised proposal, the average annual electricity bill for residential customers would increase by approximately $23 (1.6 per cent) per annum between 2016–17 and 2019–20.

Our estimate of the potential impact our final decision will have for Energex's residential customers is based on the typical annual electricity usage of 4100 kWh per annum for a residential customer in Queensland.[16] Therefore, customers with different usage will experience different changes in their bills. We also note that there are other

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[15] QCA, *Final determination: Regulated retail electricity prices 2014–15* , May 2014, p. 116; AEMC,*2014 Residential electricity price trends report*, 5 December 2014, p. 33.

[16] QCA, *Final determination: Regulated retail electricity prices 2014–15*, May 2014, p. 116; AEMC, *2014 Residential electricity price trends report*, 5 December 2014, p. 33.

factors, such as transmission network costs, wholesale and retail costs, which affect electricity bills.

Similarly, for an average small business customer in Queensland that uses approximately 10 MWh of electricity per annum, our final decision for Energex is expected to lead to lower average annual electricity bills. We estimate that based on the distribution charges from our final decision passing through to customers, we would expect the average annual electricity bill for small business customers to reduce by $51 or 1.7 per cent in 2015–16. This would be followed by decreases of about $36 or 1.2 per cent ($ nominal) per annum from 2016–17 to 2019–20. By comparison, had we accepted Energex's revised proposal, the average annual electricity bill for small business customers would increase by approximately $48 (1.6 per cent) per annum between 2016–17 and 2019–20.

Table 1.5 shows the estimated annual average impact of our final decision for the 2015–20 regulatory control period and Energex's revised proposal on the average residential and small business customers' annual electricity bills.

Table 1.5 Estimated impact of Energex's revised proposal and AER's final decision on annual electricity bills for the 2015–20 regulatory control period ($ nominal)

	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20
AER final decision						
Residential annual bill[a]	1470	1445	1428	1406	1389	1375
Annual change[c]		–25 (–1.7%)	–17 (–1.2%)	–21 (–1.5%)	–17 (–1.2%)	–14 (–1.0%)
Small business annual bill[b]	3036	2985	2949	2905	2869	2839
Annual change[c]		–51 (–1.7%)	–36 (–1.2%)	–44 (–1.5%)	–36 (–1.2%)	–30 (–1.0%)
Energex revised proposal						
Residential annual bill[a]	1470	1445	1473	1496	1518	1539
Annual change[c]		–25 (–1.7%)	28 (1.9%)	23 (1.6%)	23 (1.5%)	21 (1.4%)
Small business annual bill[b]	3036	2985	3042	3089	3136	3178
Annual change[c]		–51 (–1.7%)	57 (1.9%)	47 (1.6%)	47 (1.5%)	43 (1.4%)

Source: AER analysis; Energy Made Easy, www.energymadeeasy.gov.au; QCA, *Final determination, Regulated retail electricity prices 2014–15*, May 2014, p. 4.

(a) Based on the annual bill for a typical consumption of 4100 kWh per year during the period 1 July 2014 to 30 June 2015.

(b) Based on the annual bill for a typical consumption of 10000 kWh per year during the period 1 July 2014 to 30 June 2015.

(c) Annual change amounts and percentages are indicative. They are derived by varying 2014–15 bill amounts in proportion with total annual regulated revenue divided by forecast demand. Actual bill impacts will vary depending on electricity consumption, tariff class and other variables.