WATERNSW'S ENERGY PURCHASE COSTS - SHOALHAVEN TRANSFER SCHEME

A FINAL REPORT FOR IPART

12 MAY 2020

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1 INTRODUCTION

IPART is currently conducting a review of WaterNSW's maximum prices for the water services it provides to customers in the Greater Sydney Area, to apply from 1 July 2020 to 30 June 2025.

1.1 Frontier Economics engagement

As part of its review, IPART has engaged Frontier Economics to advise on the benchmark efficient energy expenditure for WaterNSW's Shoalhaven Transfer Scheme for the period from 1 July 2020 to 30 June 2025.

Specifically, we have been engaged to:

- Provide a recommendation on the efficient benchmark price of energy for the Shoalhaven Transfer Scheme, for each year of the 2020 determination period and for each of off-peak and peak periods.
- Account for all the costs that make up a benchmark retail price of electricity.

We have previously provided a draft report to IPART, which was publicly released by IPART along with IPART's draft report and draft determination.[1]

1.2 What has changed since our draft report?

The methodology that we have used to estimate benchmark efficient energy expenditure for WaterNSW's Shoalhaven Transfer Scheme in this report – as set out in Section 2 – is the same as the methodology that we used in our draft report.

Similarly, the input assumptions that we have used to estimate benchmark efficient energy expenditure in this report are largely the same as the input assumptions that we used in our draft report. We have updated input assumptions where new information has become available. This has been the case for the following input assumptions:

- the Renewable Power Percentage for the Large-Scale Renewable Energy Target, as discussed in Section 3.2.1
- the Small-scale Technology Percentage for the Small-scale Renewable Energy Scheme, as discussed in Section 3.2.2
- ancillary services costs, as discussed in Section 3.4.2
- energy losses, as discussed in Section 3.6.

The input assumptions that we have used for our market modelling – which are largely sourced from the Australia Energy Market Operator (AEMO) – have not been updated since our draft report. Because the input assumptions have not changed, our electricity price forecasts have not changed.

We note, however, that electricity wholesale market conditions have changed materially since our draft report, with electricity spot prices materially lower in recent months, and prices for electricity contracts

[1] Frontier Economics, *WaterNSW's Energy Purchase Costs – Shoalhaven Transfer Scheme*, A Draft Report for IPART, 24 February 2020. Available at: https://www.ipart.nsw.gov.au/files/sharedassets/website/shared-files/pricing-reviews-water-services-metro-water-review-of-prices-for-waternsw-greater-sydney-from-1-july-2020/legislative-requirements-review-of-prices-for-waternsw-greater-sydney-from-1-july-2020/consultant-report-by-frontier-economics-waternsw-energy-purchase-costs-shoalhaven-transfer-scheme-24-february-2020.pdf

for 2020/21 and beyond also lower. As we discuss in Section 3.1 our analysis suggests that the reduction in electricity spot prices is partly a result of covid-19 causing a reduction in electricity demand and partly a result of lower wholesale gas prices (which are also partly a result of the impact of covid-19). Given the uncertainty about the future impact of covid-19 we have not sought to adjust the demand and gas price assumptions that we use in our market modelling of outcomes for 2020/21 to 2024/25 for the effect of covid-19. However, the price of electricity contracts for 2020/21 to 2022/23 do provide an up-to-date indication of the market's expectation of the effect of covid-19 (and other factors) on electricity prices over this period.

1.3 This report

This report is structured as follows:

- Section 2 describes our methodology.
- Section 3 sets out the results of our analysis.
- Section 4 summarises our results.

2 METHODOLOGY

This section describes the methodology that we have used to estimate benchmark efficient energy expenditure for WaterNSW's Shoalhaven Transfer Scheme.

2.1 Forecasting efficient electricity costs for the Shoalhaven Transfer Scheme

To develop independent forecasts of efficient electricity costs for the Shoalhaven Transfer Scheme we consider the costs that an electricity retailer would face in supplying electricity to WaterNSW for the Shoalhaven Transfer Scheme. These costs are:

- Wholesale electricity costs
- Renewable energy policy costs
- Costs of complying with environmental policies (including the NSW Energy Savings Scheme (ESS) and the Climate Change Fund)
- Market fees and ancillary services costs
- Network costs
- Energy losses
- Retail operating cost and margin.

We use our standard approach to forecasting efficient electricity costs for each year of the determination period.

For wholesale electricity costs, this standard approach involves using our electricity market models to forecast wholesale electricity prices in NSW for the period of the 2020 determination. We describe our modelling approach is the Section 2.2.

For the other cost components, this standard approach involves relying on publicly reported cost estimates or regulatory allowances, as described in more detail in Section 3.

This standard approach has been previously adopted by regulators for the purposes of regulating retail electricity prices.

2.2 Modelling wholesale electricity costs

We apply a market modelling approach to estimating wholesale electricity costs in the National Electricity Market (NEM). This section discusses our approach to estimating wholesale electricity costs.

The market-based approach to determining the wholesale electricity cost to meet a load involves two steps:

- First, a forecast of wholesale market prices is required.
- Second, a forecast of the cost of purchasing electricity to meet the requirements of the Shoalhaven Transfer Scheme is required.

2.2.1 Forecasting wholesale market prices

In order to forecast wholesale market prices, we first model long-term investment outcomes in NSW and the rest of the NEM using our long-term optimisation model, *WHIRLYGIG*. This long-term investment is then used as an input to forecast prices on a half-hourly level, using our dispatch model *SYNC*.

Modelling expected investment outcomes

WHIRLYGIG is a long-term investment model for electricity markets, which relies on a detailed representation of the electricity system and, based on this, optimises total generation cost in the electricity market, calculating the least cost mix of existing generation plant and new generation plant options to meet demand. The model incorporates policy or regulatory obligations facing the generation sector, such as a renewable energy target, and calculates the cost of meeting these obligations. *WHIRLYGIG* provides a forecast of the least cost investment path as well as least cost dispatch. *WHIRLYGIG* provides an estimate of the long run marginal cost (LRMC) of electricity and the marginal cost of meeting any policy obligations. An overview of *WHIRLYGIG* is provided in **Figure 1**.

WHIRLYGIG includes a representation of demand and supply conditions in each of the regions of the NEM, including the capacity of interconnectors between the regions. *WHIRLYGIG* does not include existing intra-regional network constraints, largely because there is no robust way to forecast these network constraints in the long-term without detailed network modelling undertaken by the transmission network service providers. *WHIRLYGIG* models outcomes in the electricity market, but does not jointly model outcomes in markets for ancillary services.

Figure 1: *WHIRLYGIG* Schematic

Source: Frontier Economics

In order to model long-term investment and retirement decisions over the long-term, *WHIRLYGIG* models 80 representative demand points for each year, rather than the full 17,520 half hours of the year. *WHIRLYGIG* also models additional demand points that represent peak demand outcomes for a 1-in-

10 year (POE10). These representative demand points are defined to capture a diverse range of outcomes for demand (ensuring we account for periods of high demand), solar PV generation and wind generation (ensuring we account for periods of low generation) across seasons. *WHIRLYGIG* includes dispatch of the power system for each one of these 80 representative demand points for each year, to ensure demand can be met at each point, having regard to the level of intermittent generation for that point.

Nevertheless, it is clear that modelling sequential half-hourly outcomes is important for a robust assessment of dispatch and prices in the context of a generation mix that increasingly consists of variable wind and solar generation and storage. For this reason, we model dispatch and pricing making use of our half-hourly dispatch model – *SYNC*.

Modelling expected dispatch and price outcomes

We model dispatch and wholesale price outcomes in NSW and the rest of the NEM using our electricity market dispatch model, *SYNC*. *SYNC* is an electricity market dispatch model that focuses on detailed short-term (half-hourly or less) fluctuations in demand, supply and system constraints. *SYNC* relies on a detailed representation of the electricity system and, based on this, determines market-clearing dispatch and pricing outcomes. *SYNC* makes use of investment outcomes modelled in *WHIRLYGIG* and uses a long-term forecast of bidding patterns. The model focuses on factors that affect short term price fluctuations and volatility in the wholesale market. These include half-hourly fluctuations in demand and intermittent wind and solar generation, ramping constraints as well as start-up costs of different technologies. *SYNC* provides a dispatch and wholesale price forecast at a half-hourly level. In this way we are able to provide a forecast of the prices WaterNSW will incur over the modelling period. An overview of *SYNC* is provided in **Figure 2**.

Figure 2: *SYNC* schematic

Source: Frontier Economics

SYNC includes a representation of demand and supply conditions in each of the regions of the NEM, including interconnectors between the regions. Like *WHIRLYGIG*, *SYNC* does not include existing intra-regional network constraints, largely because there is no robust way to forecast these network constraints in the long-term without detailed network modelling undertaken by the transmission network service providers. *SYNC* models outcomes in the electricity market, but does not jointly model outcomes in markets for ancillary services.

Once we have modelled *SYNC*, we test whether the results are consistent with the investment outcomes in *WHIRLYGIG* and, if not, adjust our *WHIRLYGIG* modelling accordingly and repeat our modelling process.

We note that this sequential modelling approach – with investment decisions modelled in a long-term model with a simplified demand duration curve and dispatch and wholesale prices modelled in a half-hourly dispatch model – is consistent with the modelling framework adopted by AEMO for its Integrated System Plan.

Modelling assumptions

To undertake our *WHIRLYGIG* and *SYNC* modelling we populate the models with a set of input assumptions from AEMO's Integrated System Plan[2] (ISP) and from AEMO's Electricity Statement of Opportunities[3] (ESOO).

The key exception to this is coal price forecasts. The current coal price forecasts for NSW generators from AEMO's ISP have coal prices of around $1.50/GJ to $1.60/GJ for Bayswater and Liddell and between $3.00/GJ and $4.00/GJ for Mt Piper, Vales Point and Eraring.

Based on current international coal prices, the net-back price of coal for Bayswater and Liddell is well above the cost price included in AEMO's ISP for these plant. Indeed, the ISP estimates a new entrant coal price in Central NSW of between $3.00/GJ and $4.00/GJ. Because we consider that economic decisions should be based on opportunity cost, we have adopted AEMO's estimate of the new entrant coal price for all export-exposed coal-fired power stations.

2.2.2 Forecasting the cost of purchasing electricity

Once we have forecasts of wholesale electricity prices in NSW we then need to estimate the cost of purchasing electricity to meet the electricity requirements of the Shoalhaven Transfer Scheme.

IPART has asked us to estimate the cost of purchasing electricity in each of off-peak and peak periods, where the timing of these periods is based on the definition used within Endeavour Energy's network area. The off-peak and peak periods are defined by Endeavour Energy[4] as:

- Peak: Business days 4pm to 8pm
- Off-peak: All other times

Within each of these periods, IPART has asked us to assume a constant load. In our view this is a reasonable assumption to make about the pumping profile for the Shoalhaven Transfer Scheme. Operating at a constant load during off-peak periods, before then operating at a constant load in peak periods, is likely to reduce wholesale electricity costs (which tend to be lowest during off-peak periods) and will reduce network energy tariffs (which are lowest during off-peak periods). Operating at a constant load also reduces exposure to the network peak demand charge. We do note that operating at a variable load may enable the Shoalhaven Transfer Scheme to operate during those half-hours when wholesale electricity prices are lowest, and not to operate during those half-hours when wholesale electricity prices are highest, but operating in this way is a sophisticated approach to managing energy costs that requires continually forming a view on future wholesale electricity prices, and adjusting behaviour to suit. Given that electricity trading is not WaterNSW's principal business, we think it is reasonable to assume that WaterNSW will seek to avoid operating in this way.

The cost to WaterNSW of purchasing electricity to meet constant load within a particular period is simply based on the average wholesale electricity price within that period. For instance, the cost to WaterNSW

[2] The input assumptions that we have used are from AEMO's latest assumptions book, *2019 Input and Assumptions workbook v1.3*, released on 12 December 2019. The assumptions books is available here: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp

[3] The demand forecasts that we have used are from AEMO's latest ESOO, the 2019 ESOO. The forecasts are available here: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

[4] Endeavour Energy Network Price List: Network Tariffs 2019-2020 http://www.endeavourenergy.com.au/wps/wcm/connect/786d675c-9867-43e7-b774-096898c14580/NUOS+Price+List_201920_v1.pdf?MOD=AJPERES

of purchasing electricity to meet a load that is constant within off-peak periods is simply based on the average electricity price for all off-peak half-hours.

In estimating the cost of purchasing electricity, we also account for a contract premium of 5%, which implies that a business that seeks to purchase financial hedges to manage its risk of exposure to volatile wholesale electricity prices will face an electricity purchase cost that is 5% higher than the average spot price.

3 RESULTS

This section presents the results of our analysis.

3.1 Wholesale electricity costs

As discussed in Section 2, the market-based approach to determining the wholesale electricity cost to meet a load involves two steps:

- First, a forecast of wholesale market prices is required.
- Second, a forecast of the cost of purchasing electricity to meet the requirements of the Shoalhaven Transfer Scheme is required.

This section describes the results from each of these two steps.

3.1.1 Wholesale market prices

The wholesale spot price outcomes in NSW that are forecast in *SYNC* are shown in **Figure 3**. These wholesale spot prices are referred to as the Regional Reference Price (RRP).

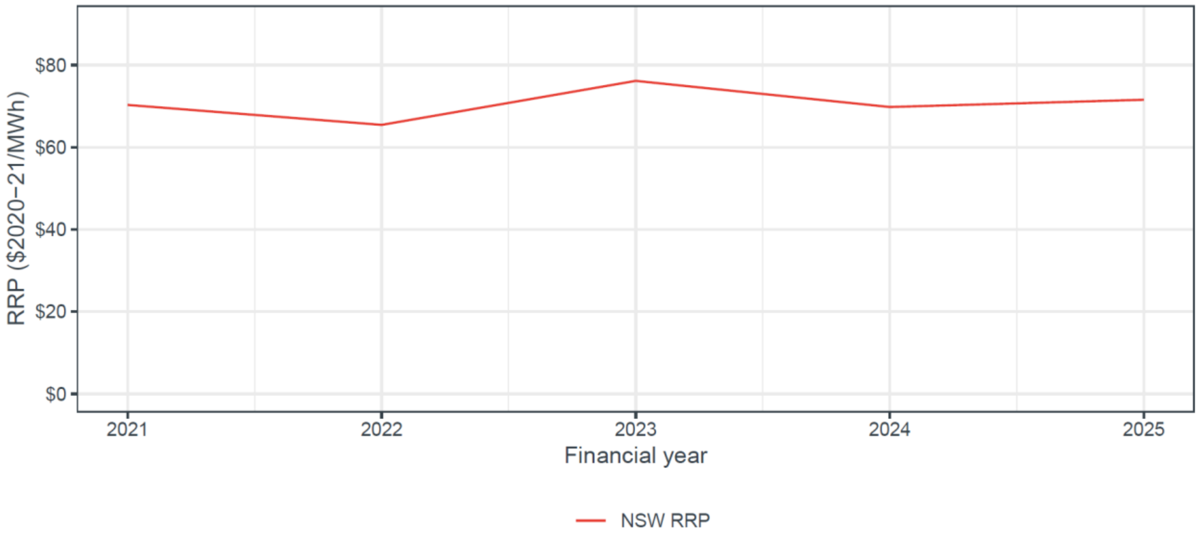
At the time of our draft report, these forecast wholesale price outcomes were materially lower than recent wholesale spot prices in NSW. For instance, the annual average NSW RRP in 2019 was $88.56. In recent months, however, wholesale spot prices in NSW, and across the NEM, have fallen materially. For instance, the average wholesale spot price in NSW was $46.16 in March and $40.37 in April. While part of this difference is seasonal (prices in the NEM tend to be lower on average during Spring and Autumn, when demand is lower), there are also other factors at play. Specifically, two factors are key drivers of the lower prices:

- The response to covid-19 has caused some reduction in electricity demand as some businesses have ceased operating or have changed the way that they operate.
- Wholesale gas prices have fallen materially in recent months (in line with falls in international LNG prices) which is reducing the price of electricity from gas-fired generation. Wholesale coal prices have also fallen in recent months. This fall in fuel prices is driven, at least in part, by reduced demand for these fuels due to covid-19.

Our modelling does not account for any persistent effect of these factors in 2020/21 and beyond. In part this is because AEMO has not updated the gas price or demand input assumptions that we use (nor, indeed, have any of the other input assumptions that we use been updated since the draft report). We could make an adjustment to these input assumptions ourselves (for instance, making an adjustment to reduce forecast demand or reduce forecast gas prices). Any such adjustment, however, would be very uncertain. It is unclear how much of the reduction in demand and gas prices in driven by the effects of covid-19, how long the effects of covid-19 will persist and, therefore, unclear what effect, if any, there will be on wholesale spot prices in NSW for 2020/21 and beyond.

Importantly, and as we discussed in our draft report, it is not lower demand and lower gas prices that account for the fact that our forecasts of wholesale prices outcomes are lower than recent wholesale spot prices in NSW. The reason that our forecast prices are lower is that our modelling incorporates significant investment in new generation plant – primarily renewable generation plant – over coming years, driven by the LRET and jurisdictional renewable energy targets. This increase in generation capacity (most of which has a short run marginal cost that is effectively zero) outstrips forecast growth in demand, resulting in lower prices. The increase in forecast wholesale prices in 2022/23 is a result of the planned retirement of Liddell power station in NSW.

Figure 3: Forecast wholesale prices in NSW



Source: Frontier Economics

Our forecast wholesale price outcomes are compared with ASXEnergy swap prices for NSW (on 11 March 2020) in **Figure 4**.

At the time of our draft report, our forecast prices were quite close to ASXEnergy prices for 2020-21 and 2021-22, but materially higher in 2022-23. Since the release of our draft report, ASXEnergy swap prices for NSW have fallen (as wholesale spot prices have fallen). As a result, our forecast prices are now materially higher for 2020-21 and 2021-22, as well as for 2022-23. This increasing difference between our forecast prices and ASXEnergy prices is highlighted in **Figure 4**. We would expect that this fall in ASXEnergy swap prices reflects the recent falls in fuel prices and electricity demand due to covid-19, which also appear to be the driver of recent falls in electricity spot prices. While ASXEnergy prices seem to be pricing in the effect of covid-19 at the moment, there is clearly significant uncertainty about what the ongoing effect of covid-19 on electricity prices will be in 2020-21 and 2021-22. As discussed, given the uncertainty about the ongoing effect of covid-19, we have not attempted to account for this effect in our forecast wholesale prices at this stage.

Figure 4: Forecast wholesale prices in NSW, compared with ASXEnergy

Source: Frontier Economics and ASXEnergy

3.1.2 The cost of purchasing electricity

We have been asked by IPART to provide the electricity purchase cost by time of use. **Table 1** shows the annual electricity purchase cost by time of use, based on the wholesale spot price outcomes in NSW that are forecast in *SYNC*. As discussed, these electricity purchase costs are a simple average of the half-hourly prices in each of off-peak and peak periods. As expected, prices in peak times are more expensive than prices in off-peak.

Note that we believe it is prudent to allow WaterNSW, or a retailer to WaterNSW, to purchase hedging contracts in advance of their pumping. The available evidence suggests that doing so by buying ASXEnergy swaps would incur a 5 percent premium. To allow for this, we increase the wholesale electricity price by 5 percent. This contract premium is incorporated in the estimates in **Table 1**.

Table 1: Annual electricity purchase costs by time of use ($/MWh, 2020-21)

TIME OF USE	2020-2021	2021-22	2022-23	2023-24	2024-25
Peak	$144.58	$140.83	$154.61	$143.87	$138.68
Off-peak	$64.57	$59.29	$70.21	$64.06	$66.84

Source: Frontier Economics

IPART also asked us to provide quarterly electricity purchase costs by time of use, which are in **Table 2** to **Table 3**. These are also based on the wholesale spot price outcomes in NSW that are forecast in *SYNC*. Quarter 1 typically has the most expensive prices, particularly in peak periods, due to the increased cooling load in summer.

Table 2: Peak quarterly electricity purchase costs ($/MWh, 2020-21)

TIME OF USE	QUARTER[5]	2020-21	2021-22	2022-23	2023-24	2024-25
Peak	3	$90.58	$87.75	$105.77	$99.09	$96.38
Peak	4	$72.59	$68.87	$79.91	$72.88	$71.38
Peak	1	$334.42	$328.00	$341.68	$315.24	$303.09
Peak	2	$81.30	$79.26	$91.40	$88.67	$84.15

Source: Frontier Economics

Table 3: Off-peak quarterly electricity purchase costs ($/MWh, 2020-21)

TIME OF USE	QUARTER	2020-21	2021-22	2022-23	2023-24	2024-25
Off-peak	3	$66.24	$60.86	$73.48	$66.75	$69.14
Off-peak	4	$52.06	$47.47	$51.26	$47.16	$49.37
Off-peak	1	$85.26	$78.84	$98.51	$89.17	$92.61
Off-peak	2	$55.16	$50.42	$58.21	$53.70	$56.80

Source: Frontier Economics

3.2 Renewable energy policy costs (LRET and SRES)

An electricity retailer supplying electricity to WaterNSW for the Shoalhaven Transfer Scheme must incur costs associated with complying with green schemes, including the costs of complying with the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). This section presents our approach to estimating costs of complying with the LRET and SRES.

Since these costs are driven by annual obligations based on annual consumption, rather than by half-hourly load, the average cost (in $/MWh) of complying with these schemes does not differ across off-peak and peak periods.

3.2.1 Cost of complying with the LRET

The LRET places a legal liability on wholesale purchasers of electricity to proportionately contribute towards the generation of additional renewable electricity from large-scale generators. Liable entities support additional renewable generation through the purchase of Large-scale Generation Certificates (LGCs). The number of LGCs to be purchased by liable entities each year is determined by the Renewable Power Percentage (RPP), which is set each year by the Clean Energy Regulator. LGCs are created by eligible generation from renewable energy power stations.

5 Quarter 3 covers July, August and September.
Quarter 4 covers October, November and December.
Quarter 1 covers January, February and March.
Quarter 2 covers April, May and June.

In order to calculate the cost to a retailer to WaterNSW of complying with the LRET, it is necessary to determine the RPP for the retailer (which determines the number of LGCs that must be purchased) and the cost of obtaining each LGC.

Renewable Power Percentage

The RRP establishes the rate of liability under the LRET and is used by liable entities to determine how many LGCs they need to surrender to discharge their liability each year. The RPP is set to achieve the renewable energy targets specified in the legislation. The Clean Energy Regulator is responsible for setting the RPP for each year. Since our draft report, the Clean Energy Regulator has released the RPP for 2020, whereas at the time of our draft report the most recent RPP was for 2019.

The *Renewable Energy (Electricity) Act* 2000 states that where the RPP for a year has not been determined it should be calculated as the RPP for the previous year multiplied by the required GWh’s of renewable energy for the current year divided by the required GWh’s of renewable energy for the previous year. This calculation increases the RPP in line with increases in the renewable energy target but does not decrease the RPP to account for any growth in demand. As a result, this calculation is likely to overestimate the RPP for a given year when energy demand is growing.

We have used the published RRP for 2020 (19.31%) to perform the default calculations for the RPP for 2020-21 to 2024-25. These values are set out in **Table 4**. These values are lower than the equivalent values from the draft report, which used the published RRP for 2019 (18.60%) to perform the default calculations for the RPP.

Table 4: Renewable Power Percentages (Calendar Year)

	2019	2020	2021	2022	2023	2024	2025
RPP (% of liable acquisitions)	18.60	19.31	18.83	18.83	18.83	18.83	18.83

Source: Clean Energy Regulator; Frontier Economics

As shown in **Table 5**, to convert the values to financial year we have taken the arithmetic average.

Table 5: Renewable Power Percentages (Financial Year)

	2020-21	2021-22	2022-23	2023-24	2024-25
RPP (% of liable acquisitions)	19.07	18.83	18.83	18.83	18.83

Source: Clean Energy Regulator; Frontier Economics

Cost of obtaining LGCs

The cost to a retailer of obtaining LGCs can be determined either on the basis of the resource costs associated with creating LGCs, or on the basis of the market price at which LGCs are traded.

For this report, we have used a market price for LGCs to determine the cost of complying with the LRET. Our current modelling indicates that the marginal resource cost associated with creating additional LGCs is zero. The reason for this is that our modelling indicates that there is sufficient existing and committed renewable generation to more than meet the current LRET, so that a marginal increase in that target will not require any additional investment in renewable generation or any additional cost. If the estimate of the cost of complying with the LRET were based on estimated resource costs, therefore, that cost of complying would also be zero.

The market price for LGCs is determined by the current price of LGCs reported by Mercari.[6] **Table 6** outlines the 40-day average LGC futures price. For the first three years, these LGC future prices are little changed since the draft report, with prices only increasing slightly. For the last two years, however, these LGC prices are materially lower, and now more consistent with the trend towards lower prices that is observable over the first three years.

There are a number of reasons potential reasons that these market prices are higher than are estimates of resource costs, including different views on the number of LGCs that are likely to be generated by existing of committed renewable generation, the number of LGCs that are likely to be voluntarily surrendered or the willingness of holders of excess LGCs to transact those LGCs.

Table 6: 40-day average LGC futures price from Mercari Rates ($/certificate, $2020-21)

	2020-21	2021-22	2022-23	2023-24	2024-25
40-day average LGC futures price	$28.41	$21.82	$13.13	$7.57	$6.79

Source: Mercari Rates

Cost of complying with the LRET

Table 7 outlines the cost of complying with the LRET, based on the inputs discussed above. Consistent with the changes in LGC prices, the cost of complying with the LRET is for the first three years is little changed since the draft report, but the cost of complying with the LRET for the last two years is materially lower.

Table 7: Cost of complying with the LRET – based on market price of LGC ($/MWh, $2020-21)

	2020-21	2021-22	2022-23	2023-24	2024-25
Cost of complying with the LRET	$5.42	$4.11	$2.47	$1.43	$1.28

Source: Frontier Economics

3.2.2 Cost of complying with the SRES

The SRES places a legal liability on wholesale purchasers of electricity to proportionately contribute towards the costs of creating small-scale technology certificates (STCs). The number of STCs to be purchased by liable entities each year is determined by the Small-scale Technology Percentage (STP), which is set each year by the Clean Energy Regulator. STCs are created by eligible small-scale

[6] Mercari (2019), http://lgc.mercari.com.au/, accessed 12th February 2020.

installations based on the amount of renewable electricity produced or non-renewable energy displaced by the installation.

Liable entities can purchase STCs on the open market or through the STC Clearing House. There is a guaranteed price of $40/STC through the Clearing House, but certificates may take some time to clear, delaying payment to sellers of STCs.

In order to calculate the cost to a retailer to WaterNSW of complying with the SRES, it is necessary to determine the STP for the retailer (which determines the number of STCs that must be purchased) and the cost of obtaining each STC.

Small-scale Technology Percentage

The STP establishes the rate of liability under the SRES and is used by liable entities to determine how many STCs they need to surrender to discharge their liability each year.

The STP is determined by the Clean Energy Regulator and is calculated as the percentage required in order to remove STCs from the STC Market for the current year liability. The STP is calculated in advance based on:

- the estimated number of STCs that will be created for the year
- the estimated amount of electricity that will be acquired for the year
- the estimated number of all partial exemptions expected to be claimed for the year

The STP is to be published for each compliance year by March 31 of that year. The Clean Energy Regulator must also publish a non-binding estimate of the STP for the two subsequent compliance years by March 31. As the time of our draft report, the relevant published estimates were the non-binding STPs for 2020 and 2021. Since the draft report, the Clean Energy Regulator has published a binding STP for 2020, an updated non-binding STP for 2021 and a non-binding STP for 2022. Both the binding STP for 2020 and the updated non-binding STP for 2021 are materially higher than the equivalent non-binding STPs that were available at the time of our draft report. The resulting higher STPs are set out in **Table 8**. After 2022, we have assumed that the STP remains constant at the 2022 level.

Table 8: Small-scale Technology Percentages (Calendar Year)

	2020	2021*	2022*	2023*	2024*	2025*
STP (% of liable acquisitions)	24.40%	19.40%	17.92%	17.92%	17.92%	17.92%

Source: Clean Energy Regulator

**Non-binding*

As shown in **Table 9**, to convert the values to financial year we have taken the arithmetic average.

Table 9: Small-scale Technology Percentages (Financial Year)

	2020-21	2021-22	2022-23	2023-24	2024-25
STP (% of liable acquisitions)	21.90%	18.66%	17.92%	17.92%	17.92%

Source: Clean Energy Regulator; Frontier Economics

Cost of STCs

For this report, we assume that the cost of STCs is equal to this STC Clearing House price of $40 ($nominal) as set out in **Table 10**.

Historically, the reported spot price of STCs has typically been at, or close to, this price of $40.

Table 10: STC costs ($/certificate, $2020-21)

	2020-21	2021-22	2022-23	2023-24	2024-25
Cost of STCs	$39.65	$38.68	$37.74	$36.82	$35.92

Source: Frontier Economics

Cost of complying with the SRES

Table 11 outlines the cost of complying with the SRES, based on the inputs discussed above. This cost is materially higher than the equivalent cost estimate from our draft report, due to higher STPs released by the Clean Energy Regulator.

Table 11: Cost of complying with the SRES ($/MWh, $2020-21)

	2020-21	2021-22	2022-23	2023-24	2024-25
Cost of complying with the SRES	$8.68	$7.22	$6.76	$6.60	$6.44

Source: Frontier Economics

3.3 Costs of complying with jurisdictional environmental policies

Legislation requires electricity businesses to comply with the NSW Energy Savings Scheme (ESS) and the Climate Change Fund (CCF). In particular:

- The ESS places an obligation on electricity retailers to obtain and surrender Energy Savings Certificates (ESC). Liability under the scheme is set as a fixed percentage of electricity sales for which ESCs need to be surrendered in each calendar year, as legislated under the *Electricity Supply Act* 1995 No. 94.
- The CCF was established by the NSW Government to support energy and water savings initiatives. It is mostly funded from the NSW electricity distribution network service providers, which pass on the costs to consumers through distribution network prices. The network tariffs discussed in Section 3.5 include the amount for the CCF.

The Australian Energy Market Commission's (AEMC) annual Residential Electricity Price Trends forecasts the expected cost of complying with these policies out to 2021-22. We have used these estimates from the AEMC and, in the absence of better information on the future costs of these policies, have assumed that the cost of complying with these policies remains constant in real terms from 2021-22. These estimates have not been updated since our draft report.

Table 12: Cost of complying with environmental policies ($/MWh, $2020-21)

	2020-21	2021-22	2022-23	2023-24	2024-25
Cost of complying with environmental policies	$5.62	$5.52	$5.52	$5.52	$5.52

Source: Australian Energy Market Commission, 2019 Residential Electricity Price Trends

3.4 Market fees and ancillary services costs

An electricity retailer supplying electricity to WaterNSW for the Shoalhaven Transfer Scheme will also face the cost of market fees and ancillary services costs. This section presents our approach to estimating market fees and ancillary services costs.

Since these costs are driven by annual obligations based on annual consumption, rather than by half-hourly load, the average cost (in $/MWh) of complying with these schemes does not differ across the scenarios.

3.4.1 Market fees

Market fees are charged to participants in the National Energy Market (NEM) in order to recover the cost of operating the market, based on the budgeted revenue requirements of AEMO, and include fees for the following functions:

- NEM;
- FRC electricity; and
- National Transmission Planner (NTP).

Market fees for the coming financial year are set out in budget documents on AEMO's website.[7] FRC electricity is immaterial for large customers as it is calculated on a per-connection basis, and so is ignored. These documents state that fees are expected to rise steadily in real terms over the period of the Determination, so growth rates have been used where present, and, in the absence of better information on AEMO's future costs, thereafter values have been kept constant in real terms. These estimates are outlined in **Table 13**. These estimates have not been updated since our draft report.

Table 13: Forecast market fees ($/MWh, $2020-21)

	2020-21	2021-22	2022-23	2023-24	2024-25
NEM	$0.57	$0.62	$0.68	$0.68	$0.68
NTP	$0.04	$0.05	$0.07	$0.08	$0.08
Total market fees	**$0.61**	**$0.68**	**$0.75**	**$0.77**	**$0.77**

Source: AEMO (2018), Electricity Functions 2019-20 Final Budget and Fees; Frontier Economics.

[7] AEMO (2019), *Electricity functions 2019-20 AEMO Final Budget and Fees.*

3.4.2 Ancillary services costs

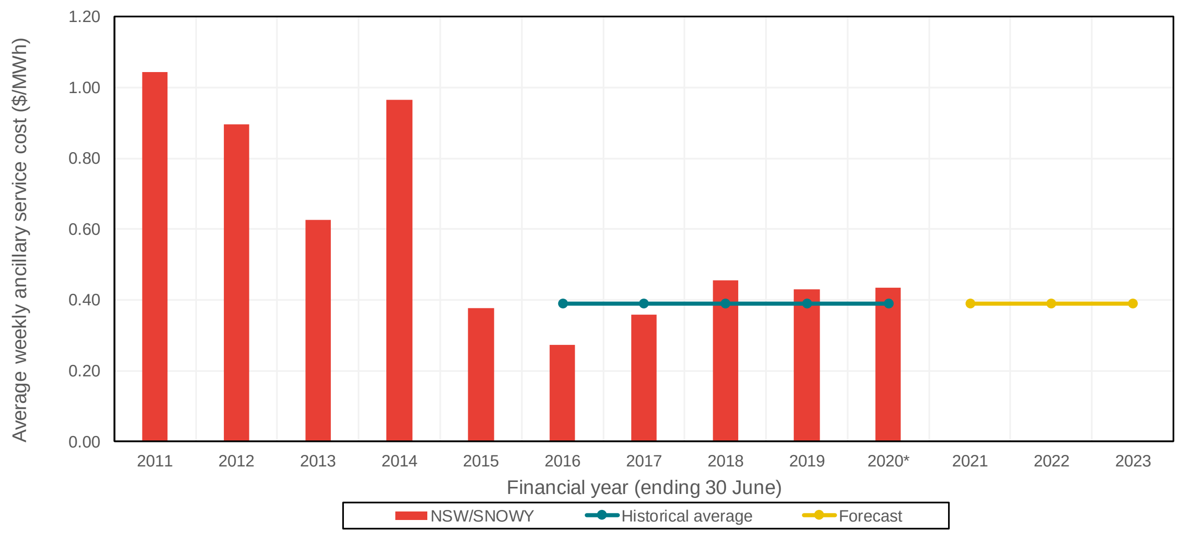
Ancillary services are those services used by AEMO to manage the power system safely, securely and reliably. Ancillary services can be grouped under the following categories:

- Frequency Control Ancillary Services (FCAS) are used to maintain the frequency of the electrical system.
- Network Control Ancillary Services (NCAS) are used to control the voltage of the electrical network and control the power flow on the electricity network.
- System Restart Ancillary Services (SRAS) are used when there has been a whole or partial system blackout and the electrical system needs to be restarted.

AEMO operates a number of separate markets for the delivery of FCAS and purchases NCAS and SRAS under agreements with service providers and publishes historic data on ancillary services costs on its web site. To estimate the future cost of ancillary services, we have examined the past 9 years of ancillary service cost data published by AEMO for the New South Wales region of the NEM.

Typically, weekly ancillary services costs have been in the range of $0.25/MWh to $0.96/MWh. Outlined in **Error! Reference source not found.** are average annual ancillary service costs by financial from 2010/11 to 2019/20.[8] Due to volatility in the historical ancillary service cost data for New South Wales over the past 10 years , we have used the arithmetic average over the past 5 years of data as the best estimate for ancillary service costs for the period of the Determination (as it appears that, recently, ancillary costs have fallen). These estimates are outlined in **Table 14**. These estimate is very slightly lower than the equivalent estimate from the draft report as a result of slightly lower year-to-date average ancillary services costs for 2020.

Figure 5: Historical ancillary service costs in New South Wales ($/MWh, $2020-21)



Source: AEMO, Frontier Economics Analysis

** Partially complete year of data*

[8] 2020 is an incomplete year of data

Table 14: Ancillary service costs ($/MWh, $2020-21)

	2020-21	2021-22	2022-23	2023-24	2024-25
Ancillary service costs ($/MWh)	$0.39	$0.39	$0.39	$0.39	$0.39

Source: Frontier Economics

3.5 Network costs

Australian electricity networks, whether transmission or distribution, are considered to be natural monopolies. As such the network tariffs that retailers pay the network businesses for use of the networks are subject to economic regulation by the Australian Energy Regulator. The pipeline is located within Endeavour Energy's sub-transmission network and information provided by IPART indicates that the relevant Endeavour Energy network tariff class is a sub-transmission time of use demand - N39 tariff.

Through using publicly available data on network tariffs we can estimate network costs that would be incurred by a retailer supplying WaterNSW. **Table 15** sets out the network use of service (NUOS) tariffs for tariff N39 for Endeavour Energy's network area for 2019-20. These tariffs are unchanged since our draft report (with Endeavour Energy's network price list for 2020-21 not yet released). In order to convert these network tariffs into average costs (in $/MWh) for each of off-peak and peak periods, we make the following assumptions:

- Consistent with advice from IPART on the load for the Shoalhaven Transfer Scheme, we have assumed that pumping will occur first in off-peak periods and then in peak periods. For this reason we have assumed that all fixed and demand-based network tariffs need to be recovered in off-peak periods (since it may be that no pumping occurs in peak periods), and consistent with the tariff structure, there are no incremental fixed or demand-based tariffs in off-peak periods.
- Consistent with advice from IPART, we calculate average costs (in $/MWh) for each of off-peak and peak periods based on the assumption of constant pumping in each of these periods. This enables us to convert fixed charges into an average charge for off-peak periods based on the amount of electricity used for pumping in off-peak periods.
- Based on the assumption of constant pumping, and assuming a power factor of 0.9, we are able to calculate the peak demand (in kVA) of the profile provided by IPART.

Table 15: NUOS Network tariffs in 2019-20 ($2020-21)

	NETWORK ACCESS ($/DAY)	HIGH SEASON ENERGY PEAK ($/KWH)	LOW SEASON ENERGY PEAK ($/KWH)	ENERGY OFF PEAK ($/KWH)	HIGH SEASON PEAK DEMAND CHARGE ($/KVA/M)	LOW SEASON PEAK DEMAND CHARGE ($/KVA/M)
N39	56.59	0.0137	0.0132	0.0121	7.75	7.65

Source: Essential Energy – Network Price List

Note NUOS tariffs include jurisdictional scheme charges

Given the uncertainty around future tariffs, we have assumed they remain constant in real terms (see **Table 16**). We note that the AER has published its final decision on Endeavour Energy's network tariffs for 2019 to 2024, and that this final decision provides a future price path. From 2019-20, the AER's final decision is that Endeavour Energy's smoothed annual revenue will fall slightly to the end of the determination period in real terms. However, there are a number of adjustments to annual revenue that occur within the regulatory period, as well as potential adjustments to individual tariffs within the regulatory period. Because of this uncertainty, we have maintained network tariffs constant in real terms.

Table 16: Network costs ($2020-21)

	2020-21	2021-22	2022-23	2023-24	2024-25
Network access charge ($/day)	56.59	56.59	56.59	56.59	56.59
High season energy peak (cents/kWh)	1.37	1.37	1.37	1.37	1.37
Low season energy peak (cents/kWh)	1.32	1.32	1.32	1.32	1.32
Energy off peak (cents/kWh)	1.21	1.21	1.21	1.21	1.21
High Season Peak Demand Charge (cents/kVA/M)	774.64	774.64	774.64	774.64	774.64
Low Season Peak Demand Charge (cents/kVA/M)	765.31	765.31	765.31	765.31	765.31

Source: Frontier Economics

3.6 Energy losses

The estimated energy purchase costs are referenced to the New South Wales Regional Reference Node (RRN) and, therefore, must be adjusted to account for transmission and distribution losses associated with transmitting electricity from the RRN to the end-user. This includes losses that occur on both the transmission network and the distribution network. We use estimates of distribution losses and transmission losses published by AEMO.[9]

The relevant estimate of distribution losses is the Distribution Loss Factor (DLF) for Endeavour Energy for the applicable network tariff (the subtransmission DLF). For transmission losses we have assumed that the relevant Marginal Loss Factor (MLF) is that for the Endeavour Energy network at Dapto (given the proximity of Dapto to the Shoalhaven Transfer Scheme). Since our draft report, AEMO have published updated, and slightly changed, estimates of both these loss factors.

As shown in **Table 17**, in the absence of any long-term forecasts of losses, we have assumed that the DLF and TLF remain constant throughout the Determination period.

[9] See AEMO (2019), *Distribution Loss Factors for the 2019/2020 Financial Year*; AEMO (2019), *Indicative Marginal Loss Factors: FY 2020-21*.

Table 17: Distribution and transmission losses

	2020-21	2021-22	2022-23	2023-24	2024-25
Distribution loss factor	1.0107	1.0107	1.0107	1.0107	1.0107
Transmission loss factor	0.9929	0.9929	0.9929	0.9929	0.9929

Source: AEMO, Distribution loss factors for the 2020/21 financial year, Table 14, 1 April 2020; AEMO, Regions and Marginal Loss Factors: FY 2020-21. 1 April 2020.

3.7 Retail operating cost and margin

An electricity retailer supplying electricity to WaterNSW for the Shoalhaven Transfer Scheme will incur retail operating costs (ROC) and must cover its retail margin.

ROC are the costs associated with services provided by a retailer to its customers, which typically include billing and revenue collection costs, call centre costs, customer information costs, corporate overheads, energy trading costs, regulatory compliance costs and marketing costs.

The retail margin represents the return to investors for retailers' exposure to systematic risks associated with providing retail electricity services. The margin can also include other costs incurred by retailers, such as depreciation, amortisation, interest payments and tax expense.

There is limited publicly available information to determine appropriate ROC and retail margin allowances for large customers because regulators in most jurisdictions only determine retail electricity prices for small customers. We have based the allowance for ROC and the retail margin on the Queensland Competition Authority's (QCA) most recent decision, which provides for a fixed ROC and retail margin allowance of $2,374.44 ($2020-21) and a variable ROC and retail margin allowance of 6.04% of total variable costs, across the Determination Period.[10] Other regulatory determinations on allowances for ROC and retail margin (including past decisions by IPART and more recent decisions by the Essential Services Commission and Independent Competition and Regulatory Commission) have focused on ROC and retail margin allowances for small customers, which are less relevant benchmarks for the Shoalhaven Transfer Scheme.

[10] An allowance of 6.04% applied to all charges, produces a ROM of 5.70%, consistent with the approach adopted by QCA in its most recent decision.

4 SUMMARY OF RESULTS

Table 18 through **Table 19** provide a summary of each of the cost components that we have estimated, for off-peak and peak periods respectively. The costs reported in **Table 18** through **Table 19** are unit costs.

The appendix contains the values for these tables converted to $/MWh.

Table 18: Estimated electricity cost components – off-peak period ($2020-21)

	2020-21	2021-22	2022-23	2023-24	2024-25
Wholesale energy costs					
EPC ($/MWh)	64.57	59.29	70.21	64.06	66.84
Losses ($/MWh)	0.23	0.21	0.25	0.23	0.24
Renewable energy policy costs					
Costs of complying with the LRET ($/MWh)	5.42	4.11	2.47	1.43	1.28
Costs of complying with the SRES ($/MWh)	8.68	7.22	6.76	6.60	6.44
Cost of complying with the environmental policies ($/MWh)	5.62	5.52	5.52	5.52	5.52
Market fees and ancillary services					
Market fees ($/MWh)	0.61	0.68	0.75	0.77	0.77
Ancillary services costs ($/MWh)	0.39	0.39	0.39	0.39	0.39
Network charges					
Network access charge ($/day)	56.59	56.59	56.59	56.59	56.59
Energy off peak (cents/kWh)	1.21	1.21	1.21	1.21	1.21
High Season Peak Demand Charge (cents/kVA or kW/M)	774.64	774.64	774.64	774.64	774.64
Low Season Peak Demand Charge (cents/kVA/M)	765.31	765.31	765.31	765.31	765.31
Retail operating cost and margin					
Allowance for ROC ($/annum)	2,374	2,374	2,374	2,374	2,374
Allowance for ROM (%)	6.04%	6.04%	6.04%	6.04%	6.04%

Source: Frontier Economics

Table 19: Estimated electricity cost components – peak period ($2020-21)

	2020-21	2021-22	2022-23	2023-24	2024-25
Wholesale energy costs					
EPC ($/MWh)	144.58	140.83	154.61	143.87	138.68
Losses ($/MWh)	0.51	0.50	0.54	0.51	0.49
Renewable energy policy costs					
Costs of complying with the LRET ($/MWh)	5.42	4.11	2.47	1.43	1.28
Costs of complying with the SRES ($/MWh)	8.68	7.22	6.76	6.60	6.44
Cost of complying with the environmental policies ($/MWh)	5.40	5.30	5.30	5.30	5.30
Market fees and ancillary services					
Market fees ($/MWh)	0.61	0.68	0.75	0.77	0.77
Ancillary services costs ($/MWh)	0.39	0.39	0.39	0.39	0.39
Network charges					
High Season Energy Peak (c/kWh)	1.37	1.37	1.37	1.37	1.37
Low Season Energy Peak (c/kWh)	1.32	1.32	1.32	1.32	1.32
Retail operating cost and margin					
Allowance for ROC ($)	2,374	2,374	2,374	2,374	2,374
Allowance for ROM (%)	6.04%	6.04%	6.04%	6.04%	6.04%

Source: Frontier Economics

APPENDIX

To convert the network access charge from $/day to $/MWh by grossing it up to an annual charge and then dividing it by the total amount of off-peak pumping for the year. A similar calculation was done for the demand charge, where a monthly amount is calculated and then divided by the total amount of off-peak pumping. This is done for both high and low season demand charges. A power factor of 0.9 was assumed for the demand charge calculations.

Since the high season charges apply from November to March, we have assumed that both Q3 and Q2 lie entirely within the low season and thus only have low season charges applied. The costs for Q1 only have the high season charges applied since it lies entirely within the high season. We have applied a weighted average for Q4 since October lies within the low season but November and December lie in the high season.

Table 20: Breakdown of costs in 2020-21 ($2020-21)

	Q3	Q4	Q1	Q2
Wholesale Electricity - Off Peak ($/MWh)	$66.24	$52.06	$85.26	$55.16
Wholesale Electricity - Peak ($/MWh)	$90.58	$72.59	$334.42	$81.30
Wholesale Electricity Losses - Off Peak ($/MWh)	$0.23	$0.18	$0.30	$0.19
Wholesale Electricity Losses - Peak ($/MWh)	$0.32	$0.26	$1.18	$0.29
- Renewable energy policy ($/MWh)	$19.72	$19.72	$19.72	$19.72
- Market fees and ancillary services ($/MWh)	$1.00	$1.00	$1.00	$1.00
- Network charges - Off Peak ($/MWh)	$14.00	$14.01	$14.02	$14.00
- Retail operating cost - Off peak ($/MWh)	$0.00	$0.00	$0.00	$0.00
- Network charges - Peak ($/MWh)	$13.24	$13.56	$13.71	$13.24
Total Off peak price ($/MWh)	$101.20	$86.98	$120.30	$90.08
Total Peak price ($/MWh)	$124.87	$107.13	$370.03	$115.55
Retail operating margin	6.04%	6.04%	6.04%	6.04%
Total Off peak price including ROM ($/MWh)	$107.31	$92.23	$127.57	$95.52
Total Peak price including ROM ($/MWh)	$132.41	$113.60	$392.38	$122.53
Composite usage rate factor (MWh/ML)	1.96	1.96	1.96	1.96
Off Peak ($/ML)	**$210.32**	**$180.77**	**$250.03**	**$187.21**
Peak ($/ML)	**$259.52**	**$222.66**	**$769.07**	**$240.15**

Source: Frontier Economics

Table 21: Breakdown of costs in 2021-22 ($2020-21)

	Q3	Q4	Q1	Q2
Wholesale Electricity - Off Peak ($/MWh)	$60.86	$47.47	$78.84	$50.42
Wholesale Electricity - Peak ($/MWh)	$87.75	$68.87	$328.00	$79.26
Wholesale Electricity Losses - Off Peak ($/MWh)	$0.21	$0.17	$0.28	$0.18
Wholesale Electricity Losses - Peak ($/MWh)	$0.31	$0.24	$1.16	$0.28
- Renewable energy policy ($/MWh)	$16.84	$16.84	$16.84	$16.84
- Market fees and ancillary services ($/MWh)	$1.07	$1.07	$1.07	$1.07
- Network charges - Off Peak ($/MWh)	$14.00	$14.01	$14.02	$14.00
- Retail operating cost - Off peak ($/MWh)	$0.00	$0.00	$0.00	$0.00
- Network charges - Peak ($/MWh)	$13.24	$13.56	$13.71	$13.24
Total Off peak price ($/MWh)	$92.98	$79.56	$111.05	$82.50
Total Peak price ($/MWh)	$119.21	$100.58	$360.78	$110.69
Retail operating margin	6.04%	6.04%	6.04%	6.04%
Total Off peak price including ROM ($/MWh)	$98.60	$84.37	$117.76	$87.49
Total Peak price including ROM ($/MWh)	$126.41	$106.65	$382.57	$117.37
Composite usage rate factor (MWh/ML)	1.96	1.96	1.96	1.96
Off Peak ($/ML)	**$193.26**	**$165.36**	**$230.80**	**$171.47**
Peak ($/ML)	**$247.76**	**$209.04**	**$749.83**	**$230.05**

Source: Frontier Economics

Table 22: Breakdown of costs in 2022-23 ($2020-21)

	Q3	Q4	Q1	Q2
Wholesale Electricity - Off Peak ($/MWh)	$73.48	$51.26	$98.51	$58.21
Wholesale Electricity - Peak ($/MWh)	$105.77	$79.91	$341.68	$91.40
Wholesale Electricity Losses - Off Peak ($/MWh)	$0.26	$0.18	$0.35	$0.21
Wholesale Electricity Losses - Peak ($/MWh)	$0.37	$0.28	$1.20	$0.32
- Renewable energy policy ($/MWh)	$14.75	$14.75	$14.75	$14.75
- Market fees and ancillary services ($/MWh)	$1.14	$1.14	$1.14	$1.14
- Network charges - Off Peak ($/MWh)	$14.00	$14.01	$14.02	$14.00
- Retail operating cost - Off peak ($/MWh)	$0.00	$0.00	$0.00	$0.00
- Network charges - Peak ($/MWh)	$13.24	$13.56	$13.71	$13.24
Total Off peak price ($/MWh)	$103.63	$81.34	$128.77	$88.30
Total Peak price ($/MWh)	$135.27	$109.64	$372.49	$120.85
Retail operating margin	6.04%	6.04%	6.04%	6.04%
Total Off peak price including ROM ($/MWh)	$109.89	$86.25	$136.55	$93.64
Total Peak price including ROM ($/MWh)	$143.44	$116.26	$394.99	$128.15
Composite usage rate factor (MWh/ML)	1.96	1.96	1.96	1.96
Off Peak ($/ML)	**$215.38**	**$169.06**	**$267.64**	**$183.53**
Peak ($/ML)	**$281.15**	**$227.87**	**$774.18**	**$251.18**

Source: Frontier Economics

Table 23: Breakdown of costs in 2023-24 ($2020-21)

	Q3	Q4	Q1	Q2
Wholesale Electricity - Off Peak ($/MWh)	$66.75	$47.16	$89.17	$53.70
Wholesale Electricity - Peak ($/MWh)	$99.09	$72.88	$315.24	$88.67
Wholesale Electricity Losses - Off Peak ($/MWh)	$0.24	$0.17	$0.31	$0.19
Wholesale Electricity Losses - Peak ($/MWh)	$0.35	$0.26	$1.11	$0.31
- Renewable energy policy ($/MWh)	$13.54	$13.54	$13.54	$13.54
- Market fees and ancillary services ($/MWh)	$1.16	$1.16	$1.16	$1.16
- Network charges - Off Peak ($/MWh)	$14.00	$14.01	$14.02	$14.00
- Retail operating cost - Off peak ($/MWh)	$0.00	$0.00	$0.00	$0.00
- Network charges - Peak ($/MWh)	$13.24	$13.56	$13.71	$13.24
Total Off peak price ($/MWh)	$95.68	$76.03	$118.21	$82.58
Total Peak price ($/MWh)	$127.38	$101.39	$344.76	$116.92
Retail operating margin	6.04%	6.04%	6.04%	6.04%
Total Off peak price including ROM ($/MWh)	$101.46	$80.63	$125.35	$87.57
Total Peak price including ROM ($/MWh)	$135.07	$107.52	$365.59	$123.98
Composite usage rate factor (MWh/ML)	1.96	1.96	1.96	1.96
Off Peak ($/ML)	**$198.86**	**$158.03**	**$245.68**	**$171.64**
Peak ($/ML)	**$264.74**	**$210.73**	**$716.55**	**$243.00**

Source: Frontier Economics

Table 24: Breakdown of costs in 2024-25 ($2020-21)

	Q3	Q4	Q1	Q2
Wholesale Electricity - Off Peak ($/MWh)	$69.14	$49.37	$92.61	$56.80
Wholesale Electricity - Peak ($/MWh)	$96.38	$71.38	$303.09	$84.15
Wholesale Electricity Losses - Off Peak ($/MWh)	$0.24	$0.17	$0.33	$0.20
Wholesale Electricity Losses - Peak ($/MWh)	$0.34	$0.25	$1.07	$0.30
- Renewable energy policy ($/MWh)	$13.23	$13.23	$13.23	$13.23
- Market fees and ancillary services ($/MWh)	$1.16	$1.16	$1.16	$1.16
- Network charges - Off Peak ($/MWh)	$14.00	$14.01	$14.02	$14.00
- Retail operating cost - Off peak ($/MWh)	$0.00	$0.00	$0.00	$0.00
- Network charges - Peak ($/MWh)	$13.24	$13.56	$13.71	$13.24
Total Off peak price ($/MWh)	$97.77	$77.95	$121.34	$85.39
Total Peak price ($/MWh)	$124.35	$99.58	$332.26	$112.08
Retail operating margin	6.04%	6.04%	6.04%	6.04%
Total Off peak price including ROM ($/MWh)	$103.68	$82.65	$128.67	$90.55
Total Peak price including ROM ($/MWh)	$131.86	$105.60	$352.33	$118.85
Composite usage rate factor (MWh/ML)	1.96	1.96	1.96	1.96
Off Peak ($/ML)	**$203.21**	**$162.00**	**$252.20**	**$177.47**
Peak ($/ML)	**$258.45**	**$206.97**	**$690.57**	**$232.94**

Source: Frontier Economics

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