Stakeholder		Issue		Notes	
Energy Queensland	Energy Costs 1 - Spot Price	a	For the 2022/23 determination, ACIL Allen modelled a range of input assumptions and produced 561 spot price simulations, ranging from $110.01/MWh down to $63 91/MWh, with an average price of $78.53/MWh. The range and average outlined on Figure 1 (below) for the 2022/23 financial year are significantly below the actual average of ~$174/MWh. Market conditions have changed since our May 2022 FD and ACILs spot price modelling has not captured the increases. EEQ therefore recommends to the QCA that it update its spot price forecasts immediately prior to the final price determination to ensure it is using the most current market data. We also recommend that spot price simulations used for this and future determinations consider dramatic movements in fuel costs and generator availability.	Our FD was finalised in May 22. However spot prices peaked in 2Q 2022. 2Q 2022 was the highest NEM average price recorded for any quarter since market commencement in 1998. The weather, demand , fuel prices , outages and availability during the high prices of 2022, would be inputs to the Power Mark to model, to develop the simulated spot prices for 23-24 . ACIL's modelling will capture the most recent market data. Dramatic movements in fuel costs and generator availability will be considered when ACIL updates the fuel ,outages and availability estimates for this review . (we need to check with ACIL if they are doing so) (Background info) Key drivers of the wholesale energy price increases - Increases in the East coast gas prices and thermal coal prices -Coal fired generation outages - planned and unplanned - shift in offers from lower price bands to higher prices / increased marginal offer prices - increased spot price volatility - through record cap returns over $300/mwh	[redacted] Section 73 - Irrelevant Information
		[redacted]	[redacted] Section 73 Irrelevant Information	[redacted] Section 73 Irrelevant Information [redacted]	[redacted] Section 73 Irrelevant Information
		[redacted]	[redacted] Section 73 Irrelevant Information	[redacted]	
		[redacted]	[redacted] Section 73 Irrelevant Information	[redacted]	

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Section 73 - Irrelevant Information

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[redacted]

Hi [redacted]

Apologies for the delay, I've been on leave!

Unfortunately there isn't anyone available tomorrow to address the committee – however I have attached the information booklet that accompanied the recent final determinations for both the notified prices and the solar feed-in tariff… these give a really good run down on the prices and key drivers (as per your email below) and form the basis of the information provided at the stakeholder information sessions (including the one in Brisbane you attended and various other members at different locations). You'll also notice that the key driver increasing the prices for electricity (the wholesale energy costs), is also the same driver of a higher solar feed-in rate this year (and may help these customers to offset bill increases).

In addition, I'll point you to some key aspects of the final report that address the issues you've raised below:

- Affordability – how we considered it in this determination, please see discussion in chapter 3 overarching framework, in particular p. 9-11
- How we estimate wholesale energy costs (based on the costs retailers incur), please see discussion in section 4.2.1, in particular p. [illegible]2-[illegible]5.

[Regulated retail electricity prices in regional Queensland 2023–24 (qca.org.au)] here is the online link to the report also.

In terms of the future outlook, I think it's fair to say forecasting the market and wholesale energy cost movements is really not something we can speculate on – however as we receive an annual delegation from the Minister, I expect work will commence on the forthcoming review towards the end of this year.

Hope this helps [redacted], happy to troubleshoot if you have any further questions ahead of your meeting tomorrow,

Kind regards,

[redacted]

[redacted]

[redacted]

Caution: external email.

Dear [redacted],

I was not sure where to direct this query, but [redacted] that I contact you.

By way of introduction, I'm with [redacted] and I convene a committee of our grower leadership that focuses on Economics & Trade. This committee discusses the impacts of matters such as the process and outcomes of the QCA determination of regional electricity tariffs, which we will discuss at our next meeting on the morning of Thurs 6th July. I am contacting you to ask whether there might be a suitable staff member from QCA that could address the committee at that meeting? I'd envisage a fairly short (10 to 20 min) presentation that advises on the drivers of increase in rates (i.e., how the retailers procure their energy from the NEM and how those market conditions have led to higher prices), and also an outlook for the future of the determination and how the QCA will assess affordability and what levers are available to ensure small businesses (e.g., irrigators) can remain competitive. And we could follow that with 15 minutes of discussion.

[redacted]

[redacted]

[redacted]

[redacted]

Hi [redacted] – will review with the team and get back to you …. We can insert words in the draft – at the minimum, in the section that updates the return to service of Callide C… .

Hi Team – please review below and we'll chat further about if there's anything further we can add at this point,

[redacted]

[redacted]

[redacted]

[redacted]
Subject: Fwd: The Australian Financial Review Digital Edition: Prices jump after return of power station delayed again

Hi [redacted],
Please see below. Can you and the team investigate this. If it's going to impact, we need some words in the draft as suggested by [redacted].
Happy to discuss.
Thanks

[redacted]

[redacted]

[redacted]
Subject: Re: The Australian Financial Review Digital Edition: Prices jump after return of power station delayed again

Morning [redacted],
Yes, based on what's reported below I'd say this is going to have an impact. Too late for the draft, but it will be caught when we use more data for the final. I'll talk

to the team about mentioning it in the draft as you suggest.
Thanks
[redacted]

[redacted]

[redacted]

Caution: external email.

[redacted]

Please see below

Is this likely to impact the regional pricing deteriminat ion

If so, can it be reflected in the draft determinat on , if it cant, and i am relaxed if it cant, we should at least provide commentary that we are aware of this and its effects cant be reflected in the draft but will be in thefinal

Cheers

This article is from the March 9 issue of Australian Financial Review Digital Edition. To subscribe, visit https://www.afr.com.

Mark Ludlow

Future wholesale electricity prices in Queensland jumped by up to $15 per megawatt hour after CS Energy announced that the return of its Callide C coal-fired power station will be further delayed by another six months to October.

As the state-owned power company awaits an independent report into what caused a catastrophic failure at the power station near Biloela in May 2021, concerns have been raised about the ongoing absence of 932 megawatts of capacity on the state's energy security and electricity prices.

Described by one energy analyst as the '' longest outage in the history of the National Electricity Market'' , the ongoing delays to the return of the C4 unit at Callide have become a major embarrassment for CS Energy and the Palaszczuk government.

CS Energy owns 100 per cent of the Callide B power station. Callide C is a joint venture with Genuity.

CS Energy yesterday confirmed the return of the 466-megawatt C3 unit, out of action since October last year, would now be delayed until September 30, for a partial return. It would be in full operation from December 31.

The return of the replacement C4 unit has been pushed back six months to October (it will not be operating at the full 466-megawatt capacity until January 31 next year) because it now needs a new cooling tower.

A CS Energy spokeswoman said: '' CS Energy's position is based on a scope of work incorporating both cooling towers and tenders CS Energy has received from contractors. We are currently working through this with our JV partner.

'' It is not unusual for generators to adjust the return to service dates for units that are undergoing major maintenance or repairs, depending on issues identified during the process.''

Future wholesale prices in Queensland for the rest of 2023 jumped up to $15 per megawatt hour yesterday after CS Energy confirmed the delays to the return of both the C3 and C4 units. The Callide power station has been plagued by maintenance issues since the 2021 accident. Its entire 1700 megawatts went off line for three hours in November last year.

Energy market watcher Paul McArdle of specialist firm Global-ROAM said the outage could be the longest in 25 years of the NEM.

Josh Stabler, managing director of energy adviser Energy Edge, said future wholesale prices for April to December in Queensland were up $10 per MWh to $15 per MWh.

'' We can be confident that the change with Callide C is the primary driver behind today's market movements ,'' he said.

'' For the same periods, the forward market is up $2 to $4/MWh and less than $1.5/MWh for NSW and Victoria respectively. This diminishing impact further away from Queensland indicates the primary source of the market uplift originated in Queensland.''

Queensland Energy Minister Mick de Brenni said he had been advised there would be '' sufficient' ' power for winter and summer, despite the delays.

'' I note the advice to the market from CS Energy and we will support their actions to ensure security of supply,'' he said.

'' Queenslanders have worked hard to build a publicly owned energy system and by keeping it that way, we can ensure the transition is orderly and fair.''

Last year's unprecedented energy market intervention by the Australian Energy Market Operator was partly due to the unplanned maintenance of a string of coal-fired power stations.

[redacted]

From: [redacted]

[redacted]

Notified Prices:

Section 73 - Irrelevant Information

[redacted]

Media release:

Third paragraph: we talk about the supply-demand balance in regional Queensland — but this is only part of the story of how we forecast energy prices. I think we need to provide a brief explanation of what are the 'energy costs' that we are estimating given that they are playing a big role in this draft decision.

Section 73 - Irrelevant Information

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Section 73 - Irrelevant Information [redacted]

Summary of analysis and findings

Consistent with previous years, ACIL estimated wholesale energy costs using a market hedging approach designed to simulate the NEM from a retailer's perspective. A core feature of this approach is that it

Section 73 - Irrelevant Information [redacted] incorporates a hedging strategy that a prudent retailer would adopt to manage spot price risk in the NEM. More specifically, this involves:

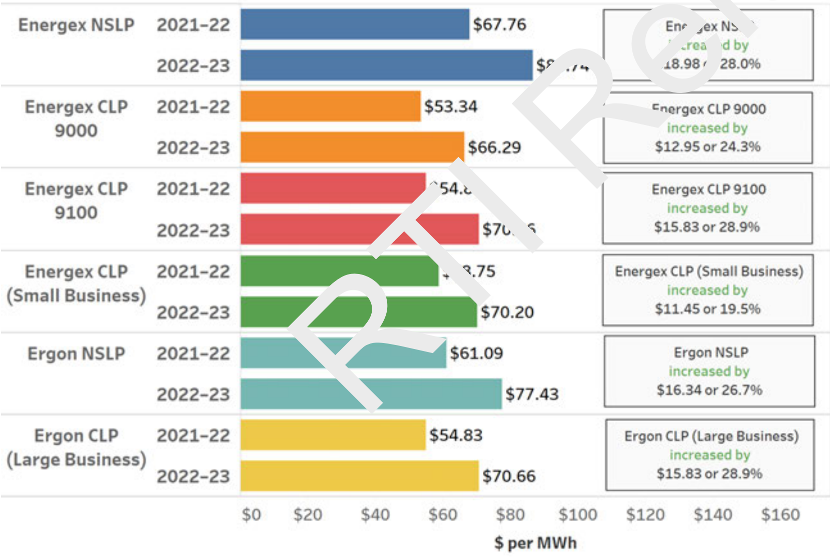
- simulating the expected spot prices that a retailer faces, considering temperature-related demand profiles, generation supply and costs, as well as power station availability; and then
- estimating wholesale energy costs for a retailer that hedges spot price risk through the purchase of ASX Energy futures[5].

Compared with last year's estimates, ACIL estimated an increase in wholesale energy costs for all customer tariff classes. ~~all customers in 2022–23, whose prices are settled on the NSLPs and CLPs identified above (Figure 1).~~ This primarily reflects a substantial increase in the trade-weighted ASX contract prices[6] for base, ~~peak~~ and cap contracts.

The increase in ASX contract prices is likely driven by:

- ~~a~~ uncertainties associated with the availability and reliability of coal-fired power plants and their impacts on the supply–demand balance in the Queensland NEM region ~~slowdown of renewable energy generators coming online (compared to recent years) and the continued unavailability of the Callide C power plant (unit 4) – both of which contribute to a tighter supply–demand balance in Queensland~~
- higher gas and coal prices due to the war in Ukraine and energy sanctions imposed on Russia
- ~~uncertainties associated with the effects of 5-minute settlement.~~

Figure 1 Wholesale energy costs by demand profiles (draft estimates)



[5] ASX energy futures are exchange-traded energy financial derivatives that allow retailers to reduce the spot price volatility risk when purchasing electricity from the NEM. For more information, see https://www.asxenergy.com.au/.

[6] Contract prices were estimated using the trade-weighted average of ASX Energy daily settlement prices of base, peak and cap contracts for each of the four quarters of 2022–23.

Energy consumption profiles - waterfalls and explanation

The NEM has been experiencing extraordinary volatility and uncertainty recently, driven by both international and domestic events, primarily due to—higher gas and coal prices and uncertainties associated with the availability and reliability of coal-fired power plants and their impacts on the supply–demand balance in the Queensland region. These events have placed upward pressure on wholesale energy prices and has increased our wholesale energy costs (WEC) estimates this year both for small and larger customers compared to last year (figures 1 and 2 below).

Figure 1: Small customer energy consumption profile from 2022/23 to 2023/24

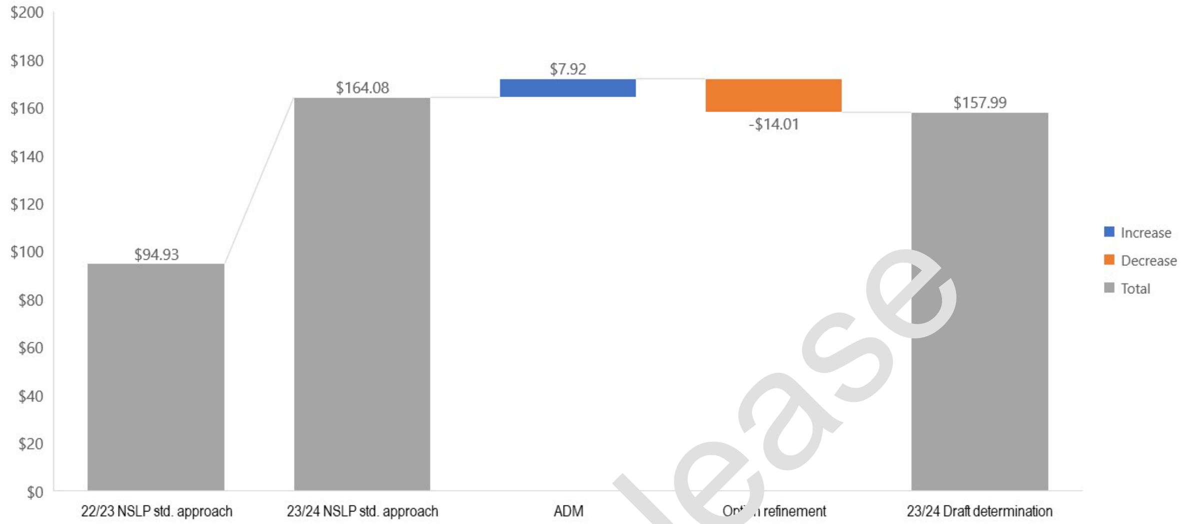
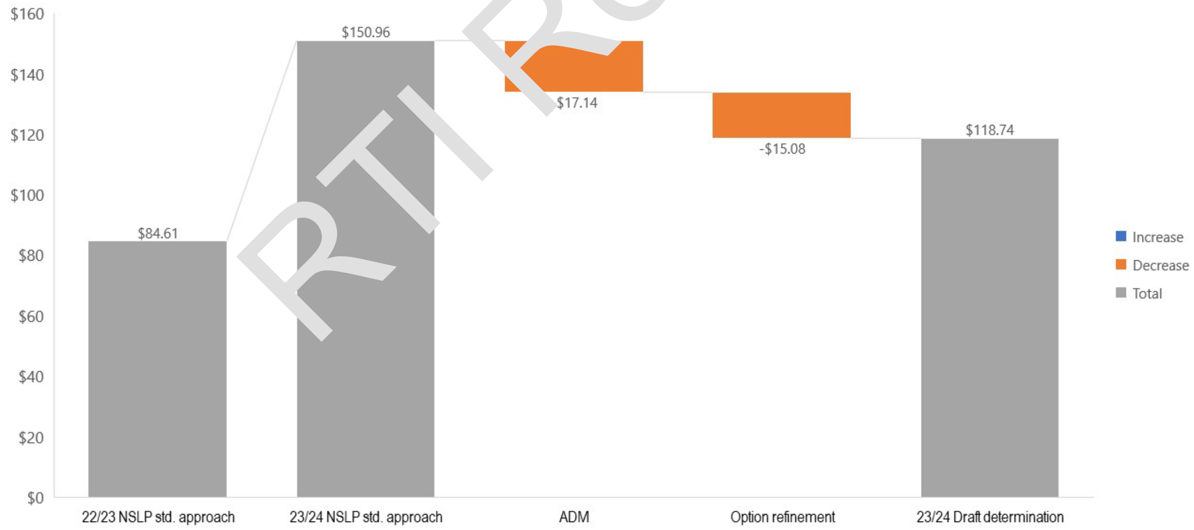


Figure 2: Large customer energy consumption profile from 2022/23 to 2023/24



We made two methodology refinements to our WEC calculations to incorporate:

- ADM data, used to inform the forecast consumption profiles, by combining the profiles of ADMs and accumulation meters/NSLP
- additional data (specifically the capture of options), to more accurately estimate ASX contract prices.

The impact of incorporating ADM data has opposite effects on the small and large customer groups. For small customers the ADM profiles are 'peakier' than the NSLP and show a reduction in daytime demand due to increased rooftop solar PV penetration over time, as we would expect. As a result, the combined profile is 'peakier' (than the NSLP alone) and is more expensive to hedge which increases the WEC. On the other hand, as the consumption profile of large customers is generally flat, including ADMs data make the combined profile flatter which reduces the hedged costs and thereby WEC.

The refinements made to the capture of options data, resulted in a decrease for in WEC for both small and larger customer groups. Refining options has reduced the WEC due to a significant number of call options being exercised at prices materially lower than the prevailing market price of base contracts. Notably, refining the way call options are calculated will not always reduce the WEC, and the impact caused in this case is largely a by-product of the volatility in financial contract markets.

1 INDIVIDUAL COST COMPONENTS

1.1 Retail component (R)

The R component consists of energy and retail costs. These include the costs of retailers purchasing electricity to supply to their customers, the costs of running their general operations, and a return for the risk they face by operating in the market.

1.1.1 Energy costs

Energy costs are a key cost component of notified prices and include costs associated with wholesale energy costs (the costs of purchasing electricity from the National Electricity Market (NEM)), other energy costs (including the Renewable Energy Target) and energy losses.

This year, we engaged ACIL Allen to provide expert advice to inform our review and energy cost estimates. As with our previous reviews, all of the information we relied on in ACIL Allen's draft report is available to stakeholders on our website.[1]

Wholesale energy costs

Retailers incur wholesale energy costs when purchasing electricity from the NEM to meet the demand of their customers. They typically adopt a range of risk management strategies to reduce their exposure to volatile wholesale electricity prices (spot price risk) when purchasing from the NEM, including pursuing contractual and operational strategies.

We are considering setting wholesale energy costs based on ACIL Allen estimates that use:

- a market hedging approach—to simulate expected spot prices that a retailer faces (having regard to the likely variation in demand profiles and generation and supply costs) then estimate wholesale energy costs for a retailer that hedges spot price risk (through exchange-traded energy financial derivatives)
- market data up until January—to take into account of the most current information and recent market developments.

This is broadly similar to the approach applied in previous years, but we intend to also consider using ADM demand profiles when estimating wholesale energy costs.

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Stakeholder submissions

EER said there had been ~~noted the~~ dramatic changes in market conditions since our last review and it was important that ~~suggested that~~ our assessment ~~should~~ incorporate ~~the following key developments~~:

- ~~the current~~ movements in fuel costs and generator availability
- the impacts of government interventions (i.e. price caps for coal and gas) in December 2022.
- On this, EER noted that ~~, noting that~~ retailers purchased contracts for the coming year prior to the Government intervention when prices were high.~~acquired ASX contracts at higher prices~~

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[1] ACIL Allen Estimated Energy Costs draft report prepared for the QCA February 2023.

~~(between May and December 2022) and purchased the majority of their contracts prior to the intervention~~[2]

EER also raised concerns about incorporating data on demand profiles for customers on ADMs when estimating wholesale energy costs. While this ~~suggested that using demand profiles of ADM~~ should deliver a more representative consumption pattern, EER noted ~~but expressed concern about such an approach as the~~ majority of its customers on ADMs are on flat-rate retail tariffs.[3]

Analysis and draft position

Our draft decision is to set the wholesale energy costs based on ACIL Allen's advice using a market hedging approach and up-to-date market data[4]. We have also refined our methodology to reflect market developments, by incorporating and policy considerations -(discussed further below).

We consider that this approach is transparent and likely to produce robust estimates that best reflect the actual costs retailers incur when purchasing electricity from the NEM. It uses the latest available market data up until 20 January 2023—including the uptake of rooftop solar PV AEMO's latest peak demand and supply projections as well as market participants' formal announcements on generation availability/operation. This means it adequately takes into account the likely variation in demand profiles and generation supply/costs within the NEM, while still meeting our draft determination timeframes.

This year, wholesale energy costs are estimated to significantly increase for small customer tariffs (by 24.7 to 66.4 per cent) and large customer tariffs (by 40.3 per cent). This reflects the significant increase in the cost of purchasing electricity in the NEM and market participants' expectations of the this in future including in response to the government interventions. We have discussed:

- the key cost drivers and impact of government interventions

~~**Key drivers and findings**~~

~~Compared to last year's estimates, draft wholesale energy costs are estimated to increase for all customer groups:~~

- ~~For the main small customer tariffs, these costs are 24.7 per cent to 66.4 per cent higher~~

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- ~~For the main large customer tariffs, these costs are 40.3 per cent higher.~~

~~These changes in costs reflect a significant increase in the trade-weighted prices for ASX base and cap contracts. The increase in these contract prices is driven by market participants expecting higher future spot prices and greater price volatility, which are likely due to:~~

- ~~higher gas and coal prices. Thermal generators have been facing higher fuel costs primarily due to the war in Ukraine and energy sanctions imposed on Russia. These developments have added further uncertainty to energy markets, which led to high and volatile gas and thermal coal prices~~

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- ~~uncertainties associated with the availability and reliability of coal fired plants and their impacts on the supply–demand balance in the Queensland region. For example, Kogan Creek and Callide C have suffered from major outages and delays in their return to service due to unforeseen circumstances.~~[5]

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[2] EER, sub. 5, pp. 6–7.
[3] EER, sub. 5, p. 8.
[4] Further information is provided in Appendix B.
~~[5] See AEMO, *Quarterly Energy Dynamics Q4 2022*, January 2023.~~

- refinements to our methodology this year

approach for estimating ~~Market developments and policy considerations~~

~~To refine our wholesale energy cost methodology, we have incorporated:~~

- ~~the potential impacts of government interventions~~
- ~~the demand profiles of ADMs~~
- ~~improvements to estimating the costs of trading in ASX call options[6]~~
- time-varying wholesale energy costs for the new ~~time-of-use~~ retail tariffs.

Key cost drivers drivers and impact of ~~G~~government interventions

Compared to last year our estimate of wholesale energy cost:

- decreases for customers settled on Energex NSLP—reflecting the projected decrease in spot price volatility in Queensland and other NEM regions
- increases marginally for customers settled on the Ergon NSLP—reflecting the increasing 'peakiness' in demand from the uptake of rooftop solar PV in the Ergon area
- increases marginally for customers settled on the Energex CLP—reflecting the load requirement and pattern of the Energex CLP.

In December 2022, the Australian Government partnered with the states and territories to introduce an Energy Relief Plan with measures to address high energy costs, including temporary price caps for gas and coal.

We are satisfied our approach ~~Our wholesale energy cost methodology~~ captures the potential impacts of these price caps through the incorporation of ASX contract prices and our spot price analysis. To calculate the trade-weighted ASX prices for 2023–24, we have used contract prices and trade volumes for Queensland since they were first traded (in mid-2018) until 20 January 2023 inclusive. Therefore, consistent with EER's views, our methodology captures the higher prices of ASX contracts that retailers acquired from May to December 2022 and before the government intervention.

Importantly, the ASX contract prices reflect, to date, the market participants' views of the potential impacts of these temporary price caps on the NEM. The potential effects of these caps are best illustrated using the movement of ASX base contracts for the summer quarter for 2023–24—that is, Q1 2024 (Figure 1).

As shown in Figure 1, since the war in Ukraine in late February 2022, ASX base contract prices for Queensland (Q1 2024) have increased substantially, reaching a record high of approximately $243/MWh. Since the commencement of the price caps, these contract prices have been lower, fluctuating between $113/MWh and $137/MWh.

[6] ~~I th s co text, call opt o s a e a type of f a c al de vat ve that g ves the holde the ght, but ot the obl gat o , to pu chase ASX base co t acts at a p edete ed p ce (k ow as the "st ke p ce") a d volu e. I excha ge fo the r ght to exerc se the opt on, the holder (buyer) w ll pay a prem um to the seller of the call opt on (regardless of whether the holder chooses to exerc se the opt on).~~

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However, in practice, retailers manage their spot price risk by locking in a price in advance for part of their electricity requirements via trading in ASX contracts. In other words, retailers already locked in a portion of their costs for 2023–24 prior to the commencement of the price caps.

This dynamic can be demonstrated using the movement in trade volume for the ASX base contracts (Q1 2024), where approximately 91 per cent of the contracts were locked in before the introduction of the price caps. This means that only 9 per cent of ASX contracts traded were influenced by the price caps (Figure 1).

The temporary price caps are expected to put downward pressure on the trade-weighted ASX contract prices, as more ASX contracts are traded while the price caps are in force. For our final determination, we will use ASX data until late April/early May 2023 to estimate contract prices. Since our data cut-off date of 20 January 2023, ASX base contract prices (for Q1 2024) have stabilised further, fluctuating between $114/MWh and $129/MWh.[7]

In line with EER's view, we have incorporated the government interventions into our spot price modelling. To do so, we assumed that the implemented price caps (i.e. $12/GJ for gas and $125/t for coal) would be applicable to all relevant fuel supply contracts and be in force throughout 2023–24. We acknowledge this is a simplified approach, noting that there are potential exemptions and a mandatory code of conduct for domestic gas producers is still being developed.[8]

However, at this stage, we consider such a modelling approach to be reasonable, as it reflects current government policies in terms of the temporary price caps. We will monitor this matter closely and incorporate further developments regarding this intervention into our spot price modelling for the final determination.

[7] For this assessment, we have used ASX contract data from 23 January until 15 February 2023.

[8] See Australian Government, The Treasury, Options to ensure the domestic wholesale gas market delivers for Australians, accessed on 31 January 2023.

Figure 1 Queensland ASX base contract for 2023–24 (Q1 2024)

Source: ASX Energy and QCA analysis.

Methodology refinements

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Demand profiles for ADMs

Consistent with EER's view, we consider incorporating the demand profiles of ADMs would improve our approximation of electricity consumption patterns. On this basis, we propose to combine the relevant ADM profiles with the NSLPs when estimating wholesale energy costs.

This is consistent with what retailers do, in practice, when developing their hedging strategies. We understand that retailers in south-east Queensland would combine the profiles for ADMs and accumulation meters (for a specific customer group) when undertaking hedging activities.

ASX options

We consider there is a need to improve our estimation of the costs that retailers face when trading in ASX call options to manage spot price volatility. Our existing approach to estimating ASX contract prices includes options by using a simplified approach, where costs of options were approximated using the volume of options traded and ASX daily settlement prices for base contracts.

However, recent market volatility has prompted us to consider refining this approach. To reflect the costs of trading in options more accurately, we propose to incorporate addition data to refine our approach including the strike prices, premiums and trade volume of call options. More details of our assessment are available in Appendix B.

~~Time-varying wholesale energy costs~~

~~As noted in section 2.3.1, we have been asked to develop a modified wholesale energy cost methodology for two new time of use tariffs, specifically to produce greater price differentials between the peak and non-peak periods (compared to the other time of use tariffs, i.e. tariffs 12B and 22B).~~

~~These price differentials are meant to incentivise customers to use more electricity during non-peak periods (i.e. during daytime hours when network utilisation is low and solar PV generation is high). To achieve these differentials, we propose to adopt an approach that involves:~~

- ~~using the wholesale energy cost estimate for small customers as a basis (i.e. the same estimate for tariffs 12B and 22B)~~
- ~~deriving a set of weightings for different time periods based on the distribution of demand-weighted spot prices throughout the day, which are typically lower during non-peak periods (i.e. daytime hours) compared to peak periods (i.e. evening hours)~~
- ~~applying these weightings to the wholesale energy cost estimate for small customers to set rates that are lower during non-peak periods and higher during peak periods (Table 2).~~

~~Using such an approach would maintain the same level of wholesale energy costs (as tariffs 12B and 22B) but change the way these costs are recovered throughout the day to encourage consumption in a specific manner. This approach is likely to provide stronger price signals than existing time of use tariffs and, as the Minister noted, could incentivise customers to take up electric vehicle charging during non-peak periods.~~

~~Table 2 Time-varying wholesale energy costs for new time-of-use retail tariffs~~

~~*Retail tariff*~~	~~*Period*~~	~~*$/MWh*~~
~~Tariffs 12C and 22C (d l d ll b time-of-use tariffs)~~	~~Peak (evening)~~	~~203.21~~
	~~Non-peak (day)~~	~~26.01~~
	~~Shoulder (night)~~	~~95.77~~

~~*Note: For tariff 12C, peak usage is 4 pm to 9 pm; shoulder (night) usage is all other times; and non-peak (day) usage is 9 am to 4 pm. For tariff 22C, peak usage is 4 pm to 9 pm weekdays; shoulder (night) usage is all other times; and non-peak (day) usage is 9 am to 4 pm all days.*~~

Other energy costs and losses

Retailers incur other energy cost when purchasing electricity from the NEM, namely:

- Renewable Energy Target (RET) costs—costs associated with the purchase of certificates to meet the targets mandated under the RET[9]
- NEM management and fees and ancillary services charges —fees levied by AEMO to cover the costs of operating the NEM and services used to manage
- ~~Ancillary services charges—charges levied by AEMO to recover costs associated with services used to manage~~ power system safety, security and reliability
- Reliability and Emergency Reserve Trader (RERT) scheme charges—charges levied by AEMO to cover the costs of maintaining power system reliability and security using reserve contracts. The RERT scheme allows AEMO to contract for emergency reservcces such as generation or demand response outside of the NEM

[9] The RET, consisting of the Large-scale Renewable Energy Target (LRET) and Small-scale Renewable Energy Scheme (SRES), provides incentives for the electricity sector to increase generation from renewable sources and reduce greenhouse gas emissions.

- prudential capital costs—the costs a retailer incurs to provide financial guarantees to AEMO and to lodge initial margins with the ASX for financial contracts.

Retailers also incur costs associated with energy losses. This is because retailers need to purchase more electricity than is demanded by customers to allow for losses that occur when electricity is transported (via transmission and distribution networks).

~~Reliability and Emergency Reserve Trader (RERT) scheme charges—charges levied by AEMO to cover the costs of maintaining power system reliability and security using reserve contracts~~

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~~—~~We also intend to consider any costs incurred due to market events during 2022, particularly in relation to the ~~costs associated with energy losses—a retailer needs to purchase more electricity than is demanded by customers, to allow for losses that occur when electricity is transported~~

~~costs related to market events during June 2022—a series of events led to the~~ trigger of the administered price cap[10] and suspension of the NEM (from 12 to 24 June 2022). If this resulted in additional costs being incurred, it could be appropriate to consider incorporating these into our estimates.

~~The costs of these events are passed on to retailers. These include the RERT costs, compensation costs (relating to the administered pricing and NEM suspension) and AEMO's directions.~~

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Stakeholder submissions

EER said ~~suggested that~~ we should estimate NEM fees using a forward looking approach and incorporate the RERT costs as part of notified prices. However, as ~~It also highlighted that~~ the AEMC is still considering ~~the~~ compensation claims relating to the administered pricing event (in June 2022), EER said ~~and until these claims are finalised~~ it would be difficult to quantify retailers' liabilities until the claims are finalised.[11]

Analysis and draft position

Our draft position is to estimate other energy costs and losses based on reliable sources of information to ensure these costs appropriately reflect those likely to be incurred by retailers. Consistent with the approaches we used in past determinations, we have estimated other energy costs and losses as follows: ~~the approaches summarised in Figure 2:~~

[10] The administered price cap is essentially a last-resort safety-net price that aims to stabilise the electricity market by capping prices in the NEM following a prolonged period of extreme prices. It is designed to limit market participants' spot price exposure and, at the same time, provide sufficient revenue for generators to cover their short-term costs and to continue supplying electricity through normal market mechanisms.

[11] EER, sub. 5, pp. 8–9.

Figure 2 ~~Approaches to e~~Estimating other energy costs and losses

RET costs	**Large-scale Renewable Energy Target (LRET) costs** These costs were estimated using forward prices for large-scale generation certificates (LGC) and renewable power percentage (RPP) values derived from mandated LRET targets and estimates of electricity acquisitions. **Small-scale Renewable Energy Scheme (SRES) costs** These costs were estimated using the clearing house price for small-scale technology certificates (STC) and small-scale technology percentages (STP) that reflect the most recent expected uptake in small-scale renewable energy systems.
NEM fees	These management fees were estimated based on the latest data from AEMO, including historical costs and projected changes in costs.
Ancillary services	These charges were estimated using the average historical costs observed over the preceding 52 weeks.
Prudential costs	These costs were estimated using AEMO's prudential requirements and margin requirements for trading in the ASX futures market.
RERT scheme charges	These charges were estimated using the historical costs published by AEMO for the preceding 52 weeks (excluding costs incurred in June 2022, see June 2022 events).
Energy losses	These losses have been estimated by applying transmission and distribution loss factors published by AEMO, in a manner that aligns with AEMO's settlement process.
June 2022 events	Costs associated with market events in June 2022 were estimated using the latest data from the AEMC and AEMO. These include the RERT costs and compensation costs published by the AEMC and AEMO to date.

This produces a forward looking estimate which as EER noted do incorporate changes in NEM fees estimated by ~~We consider these approaches to be appropriate and likely to produce reliable estimates of other energy costs and losses incurred by retailers. This is because these methodologies are aligned with the way retailers incur these costs in practice, and use the latest market data, where available and appropriate, to enhance the accuracy of the estimates.~~

~~We have estimated the NEM fees, which EER commented on, using a forward-looking approach. The draft NEM fees were estimated using the data from~~ AEMO in ~~to date, including recent historical fees and draft budgeted percentage changes for~~ 2023–24.[12] We have also

~~Consistent with EER's views, we have also~~ incorporated costs associated with the RERT and market events in June 2022 ~~in this draft determination. In terms of compensation claims relating to the administered pricing event (in June 2022), we have~~ including~~ed~~ claims ~~costs that~~ finalised by the AEMC to date. ~~has finalised to date into our draft notified prices.~~ We will update our cost estimates for the final determination if more up-to-date information is published by the AEMC and AEMO.

~~Key drivers and findings~~

~~Compared to the estimates from last year, we estimated that:~~

Compared to the estimates from last year, our draft estimate of other energy costs is around x per cent :

- x per cent ($x/MWh) lower for small customer retail tariffs [summarise aspects here]

[12] AEMO, *2022–23 AEMO Budget and Fees*, 2022..

- x per cent ($x/MWh) lower for large customer retail tariffs [summarise aspects here].
- LRET costs will increase by approximately 44 per cent ($2.19/MWh)—driven by an increase in the forward prices of large-scale generation certificates
- SRES costs will decrease by about 37 per cent ($4.04/MWh)—driven by a decline in the number of small-scale technology certificates retailers are required to purchase
- NEM management fees will increase by around 2 per cent ($0.02/MWh)—reflecting an increase in costs related to operating the NEM
- ancillary services charges will decline by approximately 58 per cent ($0.82/MWh)—due to lower costs for frequency control ancillary services (FCAS) in Queensland.[13]
- prudential costs for small customers will increase by about 27 per cent ($0.69/MWh)—reflecting elevated contract prices and greater expected price volatility in the NEM
- prudential costs for large customers will decrease by approximately 5 per cent ($0.10/MWh)—primarily due to changes in the shape of the relevant demand profile with more electricity consumed during the non-peak period, instead of during peak period
- RERT costs will decline by approximately 99 per cent ($1.00/MWh)—driven by fewer activations of the RERT to assist with power system management (this estimate excludes RERT activations during events in June 2022)
- costs associated with market events in June 2022 to be $0.89/MWh. These include the RERT and compensation costs determined and published by AEMO and AEMC to date.

~~Compared to the estimates from last year, our draft estimate of other energy costs is:~~

- ~~9.4 per cent ($2.07/MWh) lower for small customer retail tariffs~~
- ~~13.3 per cent ($2.86/MWh) lower for large customer retail tariffs.~~

As part of this draft determination, we have estimated energy losses using AEMO's 2022–23 published loss factors, as the final loss factors for 2023–24 have not yet been determined. We will update the energy losses for the final determination using AEMO's 2023–24 loss factors.

Total energy costs included in draft notified prices

In summary, draft total energy costs are estimated to increase for all customer groups, compared to last year's estimates. Figures 3 and 4 show the overall energy costs included in draft notified prices—compared to last year's estimates—by tariff type for typical small and large customers.

[13] FCAS is a process used by AEMO to maintain the frequency of the electricity system within the normal operating band around 50 cycles per second.

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Commented [redacted] Summarise these in the overall 2 dot points above.

Figure 3 Draft energy costs—typical customers on small customer tariffs (incl. GST)

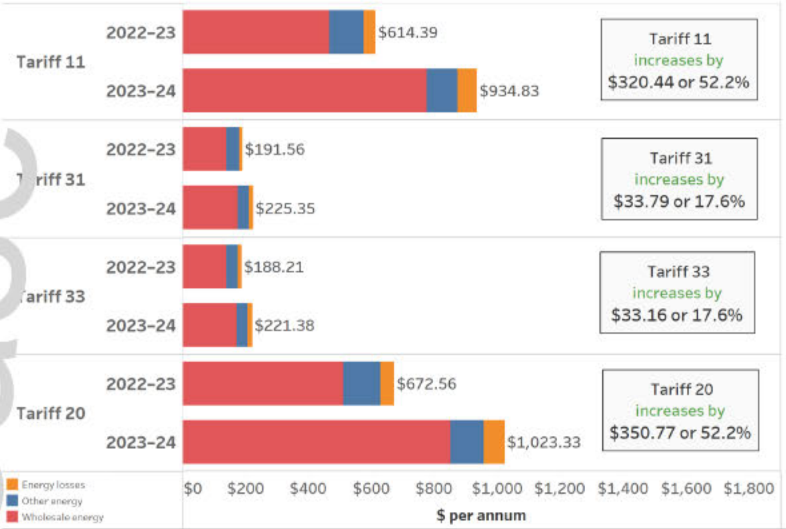
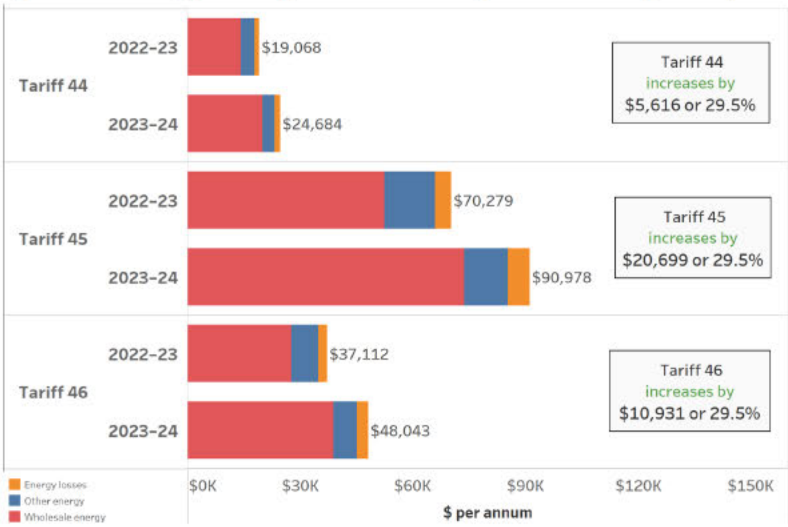


Figure 4 Draft energy costs—typical customers on large customer tariffs (incl. GST)



Note: Amounts are rounded to the closest dollar. Percentage changes are based on unrounded amounts.

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Time-varying wholesale energy costs

As noted in section 2.3.1, we have been asked to develop a modified wholesale energy cost methodology for two new time-of-use tariffs, specifically to produce greater price differentials between the peak and non-peak periods (compared to the other time-of-use tariffs, i.e. tariffs 12B and 22B).

These price differentials are meant to incentivise customers to use more electricity during non-peak periods (i.e. during daytime hours when network utilisation is low and solar PV generation is high). To achieve these differentials, we propose to adopt an approach that involves:

- using the wholesale energy cost estimate for small customers as a basis (i.e. the same estimate for tariffs 12B and 22B)
- deriving a set of weightings for different time periods based on the distribution of demand-weighted spot prices throughout the day, which are typically lower during non-peak periods (i.e. daytime hours) compared to peak periods (i.e. evening hours)
- applying these weightings to the wholesale energy cost estimate for small customers to set rates that are lower during non-peak periods and higher during peak periods (Table 2).

Using such an approach would maintain the same level of wholesale energy costs (as tariffs 12B and 22B) but change the way these costs are recovered throughout the day to encourage consumption in a specific manner. This approach is likely to provide stronger price signals than existing time-of-use tariffs and, as the Minister noted, could incentivise customers to take up electric vehicle charging during non-peak periods.

Table 1 Time-varying wholesale energy costs for new time-of-use retail tariffs

Retail tariff	*Period*	*$/MWh*
Tariffs 12C and 22C (residential and small business time-of-use tariffs)	Peak (evening)	293.31
	Non-peak (day)	36.01
	Shoulder (night)	95.77

Note: For tariff 12C, peak usage is 4 pm to 9 pm; shoulder (night) usage is all other times; and non-peak (day) usage is 9 am to 4 pm. For tariff 22C, peak usage is 4 pm to 9 pm weekdays; shoulder (night) usage is all other times; and non-peak (day) usage is 9 am to 4 pm all days.

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1 OVERARCHING FRAMEWORK~~—POLICY AND PRICING MATTERS~~

This chapter ~~provides~~provides our draft positions on key issues to consider ~~This chapter provides context relevant to this year's price determination and provides our views on~~sets out key issues ~~to be considered~~ in this year's price determination, including overarching framework matters that affect the cost level, structure and availability of ~~tariffs~~notified prices.

The key issues largely consist of matters included in the Minister's delegations (and terms of reference) that we must consider when setting notified prices. ~~and approach for setting notified prices for 2023–24.~~

~~The key issues largely consist of matters included in the Minister's delegations (and terms of reference) that we must consider when setting notified prices. For instance,~~This year, the delegations include ~~Minister has included~~ additional matters for us to consider that support broader Queensland Government initiatives relevant to developing new retail tariffs and setting ~~advanced digital meter~~small customer ~~(ADM)~~ metering charges.

The matters discussed are:

- context for setting notified prices for regional Queensland (section 3.1)
- our approach to setting notified prices for 2023–24 (section 3.2)
- our consideration of additional matters (section 3.3).

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1.1 Context

We have been involved in setting regulated electricity prices for regional Queensland under delegation from the relevant Minister since 2007–08.[1]

Regional Queensland has unique characteristics that impact electricity pricing. The costs associated with supplying electricity in regional Queensland are much higher than the costs to supply south-east Queensland customers, as electricity needs to be transported over long distances and to a sparsely located customer base.

However offsetting the high cost of supply is the Queensland Government's uniform tariff policy (UTP). In effect this policy requires that most customers in regional Queensland pay no more for electricity than their south-east Queensland counterparts.

~~In addition, we have provided information on current energy market developments relevant in the context of our review.~~ The framework in which we set regulated electricity prices for regional Queensland requires us to have regard to a range of matters including those set out in the Minister's delegation. In this way, the Minister can specify policy matters which we must have regard to. While aspects of the delegation have changed over time we have consistently been required to consider the UTP.[2]

[1] Initially we were delegated the task of determining regulated electricity prices across all of Queensland. The Queensland government deregulated retail electricity prices for south-east Queensland from 1 July 2016.
[2] We have explicitly been required to consider the UTP since 2012–13.

Accordingly we set prices in a manner that means most customers in regional Queensland pay bills lower than the costs to supply electricity with customer bills subsidised by the Queensland Government.[3]

~~The matters discussed are:~~

- ~~context andthe market environment (section 2.1)~~
- ~~the approach for setting notified prices (section 2.2)~~
- ~~additional matters in the delegation affecting for the new retail tariffs and metering charges (section 2.3)~~

~~We will consider stakeholder views on these matters and other matters that stakeholders identify as relevant to our review.~~

~~1.1 Context and mMarket environment~~

~~There are several factors that impact the electricity market, including volatility caused by global and domestic events and changes brought about by ongoing reforms. Although these factors are out of our control, they are important as they affect the market environment and conditions in the National Electricity Market (NEM) more broadly, including the notified prices we set.~~

~~Rising energy costs~~

~~The first half of 2022 was marked by extraordinary volatility and uncertainty across the NEM. Wholesale energy costs in Queensland reached record highs, likely driven by generation shortfalls, high fuel costs faced by thermal generators and high electricity demand. For instance, Queensland was the NEM's highest priced region in the June quarter of 2022, with average quarterly spot prices reaching $344/MWh.[4]~~

~~Several international and domestic factors contributed to upward pressure on wholesale energy prices in Queensland, including[5]:~~

- ~~a tighter supply–demand balance—due to a slowdown of renewable energy generators coming online (compared to recent years) and the reduced availability of thermal generators (such as the continued outage of Callide C (unit 4))~~
- ~~higher gas and coal prices—thermal generators face higher fuel costs, due to prevailing high domestic gas prices to date, higher international commodity prices and difficulties sourcing coal due to heavy rain impacting open cut mines in New South Wales and Queensland~~
- ~~weather-related high demand—resulting from continuous periods of warm weather and humidity in northern Queensland. Also, cold fronts in June drove up heating demand and coincided with record maximum demand in Queensland.[6]~~

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[3] The Queensland Government funds the difference between the cost of supply and the prices paid by customers through the community service obligation subsidy paid to Ergon Energy Queensland (EEQ). The subsidy is expected to be $568 million in 2022–23. Queensland Government Budget Strategy and Outlook 2022–23 [Budget Paper 2] 2022 p. 202.

[4] ~~AER, *Wholesale markets quarterly* [Q2 2022], Septe be 2022, p. 3.~~

[5] ~~QCA, *SEQ retail electricity market monitoring 2021–22 report*, December 2022, p 148.~~

[6] ~~AEMO, *Quarterly energy dynamics Q2 2022*, 2022.~~

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~~More broadly, we expect the rising energy costs to impact the energy cost component of notified prices (see section 3.2).~~

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~~Relevantly, the wholesale energy market conditions are likely to impact electricity prices for all customers in Queensland in the coming year, including the notified prices we set in regional Queensland.~~

~~We are mindful that electricity prices are a primary concern for stakeholders. Relevantly, the wholesale energy market conditions are likely to impact electricity prices for all customers in Queensland in the coming year, including the notified prices we set in regional Queensland.~~

~~We will continue to have regard to the Queensland Government's uniform tariff policy, which is the policy mechanism available to help deliver more affordable electricity prices to customers in regional Queensland. However, this will not necessarily shield customers from those impacts arising from increased market volatility and higher energy costs as described above.~~

~~Recently, the Commonwealth Government proposed an Energy Price Relief Plan with measures to address the higher energy costs.[7] These include temporary price caps for gas and coal which are key inputs for thermal generators. As gas price caps were approved by the Australian Parliament on 15 December 2022, our wholesale energy cost methodology would capture the potential impacts of these caps, including through our spot price analysis and the incorporation of ASX contract prices.[8]~~

~~It is important to note that our methodology reflects how retailers manage some of their spot price risk in practice, where retailers lock in a price (or a maximum price[9]) in advance for a proportion of their electricity via trading in ASX contracts. In other words, retailers have already locked in a portion of their costs for 2023–24 prior to the commencement of the temporary price caps.There are several factors that impact the electricity market, including volatility caused by global and domestic events and changes brought about by ongoing reforms. Although these factors are out of our control, they are important as they affect the market environment and conditions in the National Electricity Market (NEM) more broadly, including the notified prices we set.~~

~~We previously discussed the current market environment and the affect this has had on notified prices. In particular, and how conditions the wholesale energy market conditions have contributed to increasing electricity prices for customers across Queensland,in regional Queensland (see section xx). Importantly, these impacts are not isolated to regional Queensland customers, with increasing electricity prices likely to have broader impacts in regional Queensland and for customers in Queensland more broadly). For instance, as the maximum price retailers in south-east Queensland could charge standing offer customers (the default market offer (DMO)) increased by 11.3 per cent.[10]~~

[7] ~~Commonwealth Government, *Energy price relief plan* [med a release], Commonwealth Government webs te, med a elease o 9 Dece be 2022.~~

[8] ~~The ASX contract pr ces would reflect the market part c pants' v ews of the mpacts of the temporary pr ce caps for coal and gas on the NEM.~~

[9] ~~Reta le s ca lock the ax u p ce fo futu e elect c ty pu chases by t ad g ASX cap co t acts.~~

[10] ~~For res dent al customers w thout control load, compared to the default market offer pr ce n 2021–22. AER, *Default market offer prices 2022–23*, f nal determ nat on, May 2022, p. 7.~~

~~Further impacts are likely to be felt across Queensland in the coming year, [with our draft notified prices indicating a X per cent increase in tariff 11[11] (and the AER's draft determination expecting a X per cent increase[12] in the DMO)/including the notified prices we set in regional Queensland.]~~

~~In addition, the~~

~~Ongoing reforms~~

~~In recent years, electricity markets hasve undergone significant structural reforms, and further reforms are planned as the market continues to evolve. The reforms are expected to have ongoing impacts on the electricity market, including how market participants operate and manage risks, and manage the changes to support future technologies, services and innovations.~~

~~Some key reforms impacting the energy market in Queensland include:~~

- ~~the default market offer (DMO)—since 2019, the Australian Energy Regulator (AER) has set a DMO, which caps the price retailers can charge small customers on standard retail contracts in south east Queensland (SEQ). The DMO price for 2023–24 will be published in May 2023.~~
- ~~the network tariff reforms—in recent years, the AER approved new network tariffs for Queensland distributors (Energex and Ergon Distribution) with more complex, cost-reflective tariff structures.[13] We have introduced 15 new retail tariffs underpinned by these new network tariffs for customers in regional Queensland.~~
- ~~Queensland Government initiatives—to facilitate and accelerate the transition to renewable energy in the future, including the uptake of electric vehicles (EVs) and targeting of 100 per cent penetration of ADMs by 2030.[14,15]~~

~~The Minister's delegations have included matters relating to the DMO (see section 3.3), as well as specific matters for developing the new retail tariffs and setting the metering charges to support broader Queensland Government initiatives (see section 2.3). More broadly, we expect the rising energy costs to impact the energy cost component of notified prices (see section 3.2).~~

1.2 Approach for setting notified prices

The terms of the delegations require us to consider:

- the ~~Queensland Government's uniform tariff policy (~~UTP~~)~~, which provides that, wherever possible, customers of the same class should pay no more for their electricity, and should pay for their electricity via similar price structures, regardless of their geographic location
- using the network plus retail (N+R) cost build-up methodology to set notified prices, where the N component (network costs) is treated as a pass-through and the R component (energy and retail costs) is determined by us.

~~[11] For a typ cal customer compared to 2022–23.~~

~~[12] Fo es de t al custo e s w thout co t ol load co pa ed to the default a ket offe p ce 2022–23. AER, Default market offer pr ces 2023–24 draft determ nat on, February 2022, p. X.~~

~~[13] As part of the 2020–25 regulatory determ nat ons for Queensland d str butors (Energex and Ergon D str but on).~~

~~[14] The Queensland Energy and Jobs Plan outl nes how Queensland's energy system w ll transform to del ver clean, rel able a d affo dable powe fo ge e at o s. Fo o e fo at o , see Quee sla d Gove e t, *Queensland Energy and Jobs Plan*, Department of Energy and Publ c Works webs te, n.d., v ewed 5 December 2022 S m larly, the AEMC recently recommended a s m lar target of a un versal uptake of SMDs by 2030 n NEM (AEMC, *Review of the regulatory framework for metering services* [d aft epo t], Nove be 2022, pp , 19).~~

~~[15] Queensland Government, *Queensland's new Zero Emission Vehicle Strategy*, Queensland Government webs te, updated 20 September 2022, v ewed 5 December 2022.~~

The delegations are consistent with previous years, and ~~our approach to setting~~the way we have set notified prices in previous determinations. ~~On that basis, we are considering setting~~Our draft position is to set notified prices using the same approach ~~this year~~applied in previous years~~, having regard to~~:

- having regard to the UTP, by ~~noting we have previously set~~setting notified prices:
  - for small customers—based on the costs of supply in south-east Queensland (SEQ)
  - for large business customers—based on the cost of supply in the Ergon region with the lowest cost of supply that is connected to the NEM[16]
- ~~using~~ using the N+R methodology by ~~—where~~ applying the network prices and tariff structures approved by the AER ~~are used as the base~~ (i.e. passing through the N component) ~~and~~ then adding our estimate of energy and retail costs (i.e. the R component determined by us ~~(i.e. energy and retail costs) which we determine~~).

~~This approach has benefited most customers in previous price determinations through:~~

- ~~lower electricity prices—having regard to the UTP allows us to set notified prices for most customers at a level lower than the actual cost of supply. The cost difference is met by the Queensland Government through the payment of a community service obligation subsidy to Ergon Energy Queensland (expected to be $568 million in 2022–23)[17]~~
- ~~access to additional tariff options—we have introduced 15 new retail tariffs in recent years (underpinned by new network tariffs introduced as part of the network tariff reforms). This has provided customers in regional Queensland with additional tariff options, including access to some tariffs that other retailers may not have made available to customers in the SEQ retail electricity market.~~

Further information on the individual cost components, and our approach to setting these, is ~~discussed~~ provided in chapter ~~3~~4.

2.1 ~~Implications for electricity prices and a~~Affordability considerations

We are mindful that electricity prices in regional Queensland ~~are a~~continue to be a primary concern for stakeholders, with equitable pricing and affordability issues raised in submissions.[18]

Our approach to setting notified prices is framed by the relevant legislative factors set out in the Electricity Act. While these do not oblige us to consider affordability, we are required to consider matters ~~and the~~in the delegations.

W

~~We~~ continue to have regard to the ~~Queensland Government's uniform tariff policy~~UTP, which is the policy mechanism in the delegations ~~available to~~that helps deliver more affordable electricity prices to customers in regional Queensland ~~(explained in section 3~~ 2). Our approach to setting notified prices gives greater weight to applying the UTP than other factors we must consider.[19]

However, we acknowledge that the UTP does not ~~this does not~~ shield customers from price ~~those~~ i~~mpacts~~ncreases arising through increased market volatility and higher energy costs, which are

[16] This region is the Ergon Distribution east zone, transmission region one.
~~[17] Queensland Government, *Budget Strategy and Outlook 2022–23* [Budget Paper 2], 2022, p. 202.~~
[18] Cotton Australia sub. 1 p. 1 BRIG sub. 2 p. 1 PVW sub. 4 p. 1 QFF sub. 6 p. 3.
[19] For example we give greater weight to the UTP than cost reflectivity which we are required to consider under the Electricity Act.

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prevalent in the current market environment and impacting customers across the NEM including in south-east Queensland (see ~~as described~~ sections 2.1 and 4.2)~~above~~.

In response to the current market environment ~~On this,~~ the Commonwealth Government introduced the Energy Price Relief Plan with measures to address the higher energy costs.[20] These measures included ~~targeted bill assistance and~~ temporary price caps for gas and coal which are key inputs for thermal generators.~~[21]~~ Our approach to estimating ~~wholesale~~ energy costs ~~methodology~~ considers the potential impacts of ~~captures the impacts of~~ the price caps (see section 4.2)~~, including through our spot price analysis and the incorporation of ASX contract prices.[22,23]~~

While our ability to further address affordability concerns may be limited there are ~~Other~~ other more direct support measures ~~to address affordability concerns include more direct measures,~~ available which ensure customers who are in need (and are eligible) can access additional support. Such measures include ~~such as~~ concessions and rebates, broader income support arrangements, consumer protection frameworks and customer hardship programs. The Commonwealth Government's Energy Price Relief Plan also included targeted bill assistance measures. ~~Such measures ensure that customers who are in need (and are eligible) are able to directly access any additional specific support available when it is needed.~~

Box 1 summarises the key support measures currently available to electricity customers. We encourage any ~~electricity~~ customers ~~that are~~ facing hardship to contact their retailer to discuss support measures that may be available to them.

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Commented [redacted], finding it very hard to find anything more concrete on the coal cap than this line from news articles. Not sure if you know the place to look? If no luck, alternatively we can just remove the fn altogether

Commented [redacted] I would link to [redacted] stuff and if we need, add in a summary tag line when we know more... about the impact [I think the news stuff says it will help, but just not right away... so we'll see if there's anything a bit more explanative for a 1 liner!!]

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[20] Commonwealth Government *Energy price relief plan* [media release] Commonwealth Government website 9 December 2022.

~~[21] Gas pr ce caps were approved by the Austral an Parl ament on 15 December 2022 and the Queensland government has d ected state ow ed ge e ato s to b d to the at o al g d at a p ce co s ste t w th a do est c coal p ce of $125.~~

~~[22] The ASX contract pr ces would reflect the market part c pants' v ews of the mpacts of the temporary pr ce caps for coal and gas on the NEM.~~

~~[23] It s po ta t to ote that ou ethodology eflects how eta le s a age so e of the spot p ce sk p act ce a d reta lers have already locked n a port on of the r costs for 2023 24 pr or to the commencement of the temporary pr ce caps.~~

Box 1 Support for electricity customers in regional Queensland

Customers facing payment difficulties should contact their retailer to find out what support is available.

Hardship policies

Under the NERL, retailers have obligations to help customers that are in financial hardship or face payment difficulties.

Ergon Energy Retail's customer assist program is available to eligible customers who are experiencing financial hardship helping with ~~in~~ payment of ~~their~~ electricity bills, including via payment plans.

Government schemes, concessions and other programs and resources

Eligible Queensland pensioners and seniors can access electricity rebates.

The home energy emergency assistance scheme provides one-off emergency assistance for households experiencing problems paying their electricity bills as a result of an unforeseen emergency or a short-term financial crisis that has occurred within the past 12 months.

The electricity tariff adjustment scheme helps businesses transition from obsolete to standard tariffs by providing transition rebates on their electricity bills (eligibility requirements apply).

The ecoBiz program helps small to medium businesses develop an action plan to cut energy costs, providing benchmarking assistance to help track resource use and on-site coaching sessions to help identify opportunities to implement initiatives to cut energy costs.

The drought relief from electricity charges scheme provides drought declared farming businesses with relief from supply charges on electricity accounts used to pump water for farm or irrigation purposes.

Further information can be found on the Queensland Government's website.

Resources for stakeholders include:

(a) QFF's website provides information and resources on electricity prices, understanding your bill, government schemes and concessions available and specific information for different industries, including specific programs available for customers.

(b) Ergon Energy Retail's website provides a range of information to assist customers, including households, businesses and farming customers.

~~(b)~~(c) The Commonwealth Government's energy website provides advice for households and businesses on how to manage bills and improve efficiency as well as setting out rebates and assistance available in different jurisdictions, including Queensland.

Dispute resolution

Customers can contact the Energy and Water Ombudsman Queensland for information on how to lodge a complaint or resolve a dispute involving their electricity, gas or water supplier.

Commented [redacted] Removed business energy savers program, as it doesn t appear to be available anymore (gov site says it s a previous energy saving plan):
The business energy savers program provides free audits to agricultural customers and large businesses on their energy usage and advice on how to reduce electricity costs by using electricity more efficiently. The Queensland Government worked with the Queensland Farmers' Federation (QFF) to deliver the program (180 agricultural businesses are reported to have used this program to date).
...
ecoBiz seems to be the new thing

Commented [redacted] roger that!
We might message Andrew (dept) to see if he has anything to add)... he would know surely!

Commented [redacted]: Follow up with Andrew after we receive letter on delay

Additional matters

The terms of the delegations include additional matters this year, which relate to Queensland government initiatives aimed at facilitating and accelerating the transition to renewable energy (including the uptake of electric vehicles (EVs)) and targeting 100 per cent penetration of advanced digital meters (ADMs) by 2030.[24,25]

~~1.3~~

New retail tariffs

W~~T~~e have been delegated the task~~he terms of the delegation require us to consider~~ of developing two new retail tariffs that build on the existing small customer time-of-use (TOU) tariffs 12B and 22B (the 'solar-soaker' tariffs), namely:

- a residential 3-rate time of use energy tariff
- a small business 3-rate time of use energy tariff.

The terms of the delegation provide for the N component of the new retail tariffs to be set using the approach we apply for existing TOU tariffs 12B and 22B. However ~~On this the Minister said EV and battery storage electricity pricing is important in the context of the Queensland Government's initiatives aimed at supporting the use of more renewable energy to ensure suitable tariff options are in place for customers to make the most of charging options during the day (when network utilisation is low and solar PV generation is high).[26]~~

~~The~~ the delegation includes specific pricing considerations for setting the ~~energy costs~~R component for the new retail tariffs~~ which the Minister said would 'provide sharper retail tariff price signals' compared to the existing TOU tariffs 12B and 22B.[27]~~. In particular we have been asked to develop a methodology to provide greater price differentials between peak and non-peak periods (compared to the existing TOU tariffs 12B and 22B).[28]

The Minister said these tariffs would mean suitable options are in place for EV customers to make the most of charging options during the day (when network utilisation is low and solar PV generation is high), supporting the use of more renewable energy, consistent with the Queensland Government's initiatives.[29]

The ~~On this, the Minister said EV and battery storage electricity pricing is important in the context of the Queensland Government's initiatives aimed at supporting the use of more renewable energy, to ensure suitable tariff options are in place for customers to make the most of charging options during the day (when network utilisation is low, and solar PV generation is high).[30]~~

~~Developing On this the Minister said EV and battery storage electricity pricing is important in the context of the Queensland Government's initiatives aimed at supporting the use of more~~

[24] The Queensland Energy and Jobs Plan outlines how Queensland's energy system will transform to deliver clean reliable and affordable power for generations. For more information see Queensland Government *Queensland Energy and Jobs Plan* Department of Energy and Public Works website n.d. viewed 31 January 2023. Similarly the AEMC recently recommended a similar target of a universal uptake of smart meters by 2030 in NEM (AEMC *Review of the regulatory framework for metering services* draft report November 2022 pp. ii 19.).

[25] Queensland Government, *Queensland's new Zero Emission Vehicle Strategy*, Queensland Government website, updated 20 September 2022 viewed 31 January 2023.

~~[26] Append x A: M n ster's cover letter.~~

~~[27] Clause 2(b) of the terms of reference for the new reta l tar ffs, Append x A.~~

[28] Clause 2(b) of the terms of reference for the new retail tariffs Appendix A.

[29] Appendix A: Minister's cover letter.

~~[30] Append x A: M n ster's cover letter.~~

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~~renewable energy to ensure suitable tariff options are in place for customers to make the most of charging options during the day (when network utilisation is low and solar PV generation is high).[31]~~

development of these new ~~new~~ retail tariffs ~~in this manner, including having regard to the additional pricing considerations,~~ was initially canvassed ~~(~~and generally supported by stakeholders~~)~~ as part of last year's notified price review. ~~As the new retail tariffs are underpinned by existing small customer tariffs, they will be similar in structure and overall cost to the notified prices we set as part of this review (for residential tariff 12B and small business customer tariff 22B). We note that the new retail tariffs will be developed in addition to the existing retail tariffs (not replacing them).~~

~~However, setting the R component to influence customer behaviour would require us to set new retail tariffs that have time-varying energy costs, which does not reflect how retailers are likely to incur their costs. For instance, we currently include a flat rate energy cost component in notified prices, which best reflects how retailers are likely to incur costs in practice.[32]~~

~~While this would be a departure from the N+R methodology we usually apply, it would be consistent with the policy guidance from the Minister and was generally supported by stakeholders in our last notified price review. It is also reflective of the evolving market conditions, with the accelerated roll out of ADMs giving customers the ability to manage their energy use and consumption patterns more efficiently.[33] This means that time-varying wholesale energy costs are likely to be more appropriate as the penetration of ADMs increases.~~

~~On this basis, and subject to stakeholder comments, we intend to develop the new retail tariffs consistent with the delegation. We have set out the proposed approach for setting energy costs for the new retail tariffs, including ways to provide the sharper price signals desired, in section 3.2.1.~~ Stakeholder submissions

In general, stakeholders were supportive of us developing new retail tariffs aimed at providing sharper price signals to customers.[34] However stakeholders raised a range of matters for us to consider:

- Many stakeholders emphasised the need for the tariffs to be made available beyond EV and battery storage customers.[35] On this BRIG said we should consider allowing large SAC irrigation customers operating in the 100–160MWh bracket access to the new retail tariff.[36]
- BRIG suggested price levels for the new small business retail tariff and said that the peak period for the TOU tariffs should be reduced from five to three hours.[37]
- The Pioneer Valley Water Co-operative said the new tariffs did not take into account that for agricultural irrigation projects it is optimum to operate at night.[38]
- QFF said the new tariffs must be cost-reflective to encourage EV users to charge at optimal times. More broadly QFF said costs to upgrade the network for EV's must not be spread

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[31] Appendix A: Minister's cover letter.
~~[32] Further nformat on on how we set energy costs s d scussed n sect on 3.2.~~
~~[33] See sect on 3 2 2 of the not f ed pr ces f nal determ nat on 2022 23, wh ch d scusses emerg ng ssues and pr c ng opt ons the co text of elect c veh cles.~~
[34] Ergon Energy Network and Energex sub. 3 p. 1 BRIG sub. 2 p. 2 EER sub. 5 p. 10.
[35] Cotton Australia sub. 1 p. 1 BRIG sub. 2 p. 2 EER sub. 5 p. 10.
[36] BRIG sub. 2 p. 2.
[37] BRIG sub. 2 p. 2.
[38] Pioneer Valley Water Co-operative sub.4 p. 1.

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across the network and users should be consulted on the impacts EV's could have on the NEM.[39]

- EER said instead of ~~implementing~~introducing the new retail tariffs in addition to existing tariffs 12B and 22B we should make these obsolete (with a 24-month phase-out date) or alternatively repurpose the existing tariffs~~)~~. EER said this was appropriate, given~~given~~ the large suite of regulated retail tariffs and ~~that as~~ the minimal impact it would have on customers. On our approach to setting the R component EER recommended we apply a weighted calculation using both digital meter and net system load profile (NSLP) data. EER said the majority of its digital metered customers were on flat-rate tariffs meaning their load shapes may not reflect the load profile of a customer on a TOU tariff. Further, it said the relatively small number of customers on tariffs 12B and 22B would not enable us to build wholesale energy costs for the new tariffs.[40]

[redacted] Suggested wording changes to give a bit more flavour of why they are suggesting this (avoid further increasing the tariff schedule). If we are also using 24 month date due to EQ suggesting it, we should also reference that up here too.

Analysis and draft position

~~However setting the R component to influence customer behaviour would require us to set new retail tariffs that have time-varying energy costs which does not reflect how retailers are likely to incur their costs. For instance we currently include a flat-rate energy cost component in notified prices which best reflects how retailers are likely to incur costs in practice.[41]~~

~~While this would be a departure from the N+R methodology we usually apply it would be consistent with the policy guidance from the Minister and was generally supported by stakeholders in our last notified price review. It is also reflective of the evolving market conditions with the accelerated roll out of ADMs giving customers the ability to manage their energy use and consumption patterns more efficiently.[42] This means that time varying wholesale energy costs are likely to be more appropriate as the penetration of ADMs increases.~~Our draft position is to set the two new retail tariffs (to be identified as tariffs 12C and 22C in the draft gazette notice) by:

- setting the N component by applying the network prices used to set existing TOU tariffs 12B and 22B (i.e. the relevant network prices for the Energex distribution area but utilising Ergon Distribution tariff structures)
- setting the R component by:
  - estimating time-varying energy costs whereby existing wholesale energy cost estimates are used as a base and allocated to different time periods on a set of weightings aligned with the distribution of spot price variations throughout the day
  - establishing retail costs using the same approach taken to set existing TOU tariffs 12B and 22B (i.e. adjusting last year's fixed retail costs for inflation and maintaining last year's variable retail cost allocators).

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As the Minister said, the intent of the two new retail tariffs is to provide stronger price signals than the existing TOU tariffs which could encourage use during daytime periods where network

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[39] QFF sub. 6 pp. 4–5.
[40] EER sub. 5 p. 11.
~~[41] Fu the fo at o o how we set e e gy costs s d scussed sect o 3.2.~~
~~[42] See sect on 3 2.2 of the not f ed pr ces f nal determ nat on 2022 23 wh ch d scusses emerg ng ssues and pr c ng opt ons n the context of electr c veh cles.~~

utilisation is typically low.[43] This could limit the potential need for network upgrades and associated costs that are of concern to QFF.

The terms and conditions for the new retail tariffs will be consistent with the existing TOU tariffs 12B and 22B. This means the new retail tariffs will not be restricted to EV and battery storage customers. While the tariffs aim to encourage a more sustainable uptake of EVs the tariffs will be available to residential and small business customers who can access existing tariffs 12B and 22B respectively.[44]

Setting the new retail tariffs in the manner described above is consistent with the broader pricing approach (see section 3 1) and the specific considerations for the two new retail tariffs.

Capping prices and establishing retail tariff structures (including peak periods) different from the corresponding network tariffs would not be consistent with the delegation including requirements to consider the N+R methodology and the UTP. Similarly, with respect to QFFs view that EV customers should face cost reflective prices while this is a factor we consider under the Electricity Act we must also consider the UTP.

While setting energy costs in the manner described above is a departure from our usual approach and does not reflect how retailers are likely to incur their costs,[45] it is consistent with policy guidance from the Minister. It is also reflective of the evolving market conditions with the accelerated roll-out of ADMs giving customers the ability to manage their energy use and consumption patterns more efficiently.[46] This means that time-varying wholesale energy costs are likely to be more appropriate as the penetration of ADMs increases.

We provide further detail on our approach to setting the individual N and R components in chapter 4.[47]

While the Minister's cover letter indicates that the new retail tariffs will be additional to the existing TOU tariffs 12B and 22B,[48] we acknowledge EER's view that the existing tariffs should be phased-out given the number of regulated retail tariffs already available. We also note it ~~views~~ considers ~~that~~ the customer impacts from making the existing tariffs obsolete (with a 24-month phase-out date) or repurposing the tariffs would be minimal.

As we~~'ve~~ noted previously in our review of the retail tariff schedule as part of our 2022–23 determination providing too many tariff options (particularly of the same tariff type) can be counter-productive and may make it more difficult for customers to assess their options and switch to alternative tariffs.

Our draft notified prices show that the new retail tariffs will be similar in structure and overall cost to the existing TOU tariffs 12B and 22B. Further it is our understanding that the existing

[43] Given the intent of these tariffs is to encourage electricity use during the day these tariffs may not be well suited to irrigation customers who prefer to operate at night. We encourage customers to contact Ergon Retail and explore what retail tariff options are available to them.

[44] This means the new retail tariffs will not be available to irrigation customers operating in the 100–160MWh bracket. Customer demand thresholds are established in legislation and not something we can change. As such these concerns go beyond the scope of our review. We explain how we are constrained in considering such matters in Table X.

[45] For instance we currently include a flat-rate energy cost component in notified prices which best reflects how retailers are likely to incur costs in practice (see section 4 2).

[46] See section 3 2.2 of the notified prices final determination 2022–23 which discusses emerging issues and pricing options in the context of electric vehicles.

[47] We have addressed EER's concerns on approach to setting the R component in section 4 2.

[48] Appendix A: Minister's cover letter.

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tariffs have relatively low uptake (less than~~approximately 26~~ 50 NMIs and ~~124~~ 150 NMIs assigned respectively).[49]

Accordingly, with the introduction of the~~se~~ new TOU tariffs, ~~W~~we are minded to make the existing TOU tariffs 12B and 22B obsolete. We seek stakeholder views on this matter, including whether there is merit in retaining these tariffs or whether these tariffs should be removed and if the 24-month phase-out date proposed by EER is appropriate.~~ and whether is appropriate~~ We also ~~also~~ seek to understand the impact on customers, including to understand whether customers have made investments or otherwise structured their business to take advantage of these tariffs. Should stakeholders consider there to be minimal impact on customers, we seek views on whether repurposing the existing TOU tariffs may be an appropriate alternative to removing them in this instance.[50]

~~On this basis, and subject to stakeholder comments, we intend to develop the new retail tariffs consistent with the delegation. We have set out the proposed approach for setting energy costs for the new retail tariffs, including ways to provide the sharper price signals desired, in section 3.2.1.~~

1.3 Metering ~~charges~~ costs (bring Thomas' work on new matters up here)

The delegation requires us to consider:[51]

- setting advanced digital meter (ADM) charges for small customers based on:
  - Energex (SEQ) metering costs
  - forecast deployment rates for advanced digital meters in regional Queensland
  - cost recovery, as an element of the R components, across all standard retail contract customers for each regulated tariff
- setting a retail charge based on Ergon Energy Retail's average costs of manually reading a type 4A meter, for customers who have voluntarily disabled the remote communication function of their ADM.

The delegation contains different matters for us to consider when setting ADM charges this year.[52] The Minister's cover letter noted that enabling retailers to recover the costs associated with the provision of all metering services is important in the context of the Queensland Government broader energy plans, which targets 100 per cent penetration of ~~AMDs~~ ADM devices by 2030.[53] The Minister also said it is important to ensure similar customers do not pay different amounts simply based on the type of meter they have (consistent with the UTP).[54]

Commented [redacted] We've tended to avoid giving exact customer numbers due to potential confidentiality so I suggest rounding up to a whole number.

Given the extra time we have, might be worthwhile asking if EQ can give us more up to date customer numbers for these tariffs, since these numbers were from before our last determination was made.

Commented [redacted] Personally, I think a 12 month would be sufficient as that is consistent with the approach we took last year and means we don t need to calculate the tariffs next year. but I understand theres merit in deferring to EER's 24 month period (since they are the retailer) so happy to leave as is.

Commented [redacted]: Have discussed with Daniel and maintained the 24month period, given this was the period proposed by the retailer and it does not seem unreasonable. However happy to change if you disagree Emma

[49] As at 25 April 2022.

[50] Repurposing the existing TOU tariffs would mean tariffs 12B and 22B become the new retail tariffs, with energy costs calculated according to our new methodology described above. Customers would no longer be able to access existing TOU tariffs calculated according to our usual approach and there would be no phase-out period. In effect, tariffs 12B and 22B would be replaced with the new retail tariffs.

[51] Appendix A: Minister's delegation, terms of reference, paragraph 2(d).

[52] We first set ADM charges as part of the 2020–21 final determination of notified prices. Prior to this, metering charges for small customers were set separately by the Minister following our determination of notified prices.

[53] Queensland Government, *Queensland Energy and Jobs Plan: Power for generations—70% Renewable Energy by 2032*, September 2022, p 36.

[54] See our final price determinations for 2020–21, 2021–22 and 2022–23 on our *Regional electricity prices* web page.

~~We are considering setting the metering charges consistent with the delegation, which reflect broader Queensland Government initiatives. This approach would result in:~~

- ~~setting ADM charges that reflect the actual cost to retailers' of providing metering services, including the additional costs of manual meter reads~~

~~all customers paying a similar amount for metering charges (consistent with the UTP), with the cost of the ongoing roll-out of ADMs shared among all customers.~~ Stakeholder submissions

EER recommended that we apply a similar methodology to that applied by the AER in calculating metering charges for the 2022–23 DMO prices.[55]

With respect to determining the average costs of manually reading a type 4A meter EER said this would be difficult and complicated by the geographic location of the meter, access to the meter and availability of meter reading staff. It stated that only a small number of its customers have chosen to disable the communication function and its preference was to remove the ability for a customer to elect to disable meter communications which would overcome the need for this charge. Accordingly it suggested the fee be aligned to the special read contained within Schedule 8 of the *Electricity Regulation 2006 as a* short term solution.[56]

QFF said detailed consultation should be undertaken to understand what the impact of the metering costs will be for consumer energy bills.[57]

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Analysis and draft position ~~We are considering setting the metering charges consistent with the delegation, which reflect broader Queensland Government initiatives. This approach would result in:~~

~~setting ADM charges that reflect the actual cost to retailers' of providing metering services, including the additional costs of manual meter reads~~

~~all customers paying a similar amount for metering charges (consistent with the UTP), with the cost of the ongoing roll-out of ADMs shared among all customers.~~

> ~~Overarching framework matters~~
>
> ~~We seek stakeholders' views on the key issues we identified relating to:~~
>
> - ~~our approach for setting notified prices~~
> - ~~developing the new retail tariffs and setting metering charges.~~

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[55] EER, sub. 5, p. 10.
[56] EER, sub. 5, p. 10.
[57] QFF, sub. 6, p. 3.

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1 INDICATIVE BILL IMPACTS

Overall, draft notified prices indicate that typical customers[1] on all major tariffs can expect an increase in their electricity bill this year:

- for small customers, the increase is x [if different aspects, can identify here using similar sentence below]
- for large customers, the increase is X. [[if different aspects, can identify here using similar sentence below]

[If the same aspects increasing small and large: The increase in customer tariffs is largely due to a significant increase in [estimated energy costs], as well as increases in x.]

This chapter provides a~~A~~ snapshot of the key elements driving notified price increases, as well as ~~and further detail on the~~ indicative customer bill impact charts and comparisons~~s is provided below.~~[2]~~. Our analysis on individual cost components is provided in chapter 4 and the draft notified prices are set out in chapter 6.~~

~~Importantly, an individual customer's actual bill will vary depending on how much electricity they use. We strongly recommend that customers engage with their retailer for further advice and information reflecting their individual circumstances.~~

1.1 Why are notified prices increasing this year?

~~1.1~~

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Rising energy costs

The increase in energy costs has been driven by higher wholesale energy costs across the national energy market (NEM).

~~T~~The NEM has faced extraordinary volatility and uncertainty in recent times. This has ~~e impacts~~ have been felt across Queensland, with wholesale energy costs reaching record highs. For instance, Queensland was the NEM's highest priced region in the June quarter of 2022, with average quarterly spot prices reaching $344/MWh.[3]

Several international and domestic factors contributed to upward pressure on wholesale energy prices in Queensland, including:[4]

- a tighter supply–demand balance—due to a slowdown of renewable energy generators coming online (compared to recent years) and the reduced availability of thermal generators (such as the outages experienced at Kogan Creek and Callide C (units 3 and 4))
- higher gas and coal prices—thermal generators face higher fuel costs, due to prevailing high domestic gas prices to date, higher international commodity prices and difficulties sourcing coal due to heavy rain impacting open cut mines in New South Wales and Queensland,

[1] The typical customer for a given tariff is the median or middle customer in terms of consumption among all customers on the same tariff in regional Queensland. Typical customer consumption data was provided by Ergon Retail (see Appendix E).
[2] See chapter 4 and 6 for detailed information on the individual cost components and draft notified prices (respectively).
~~[3] AER, *Wholesale markets quarterly* [Q2 2022], September 2022, p. 3.~~
~~[4] QCA, *SEQ retail electricity market monitoring 2021–22 report*, December 2022, p. 148.~~

ongoing impacts from the war in Ukraine and the continuing global supply constraints resulting from covid-19

- weather-related high demand—resulting from continuous periods of warm weather and humidity in northern Queensland. Also, cold fronts in June drove up heating demand and coincided with record maximum demand in Queensland.[5],[6]

~~[Include a sentence outlining what has happened to wholesale prices since first half of '22 - check with pricing team. While wholesale energy costs have fallen from the peak in early 2022, they remain historically high & volatile?]~~

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1.2 Indicative customer bill impacts

The ~~We have prepared c~~charts show~~ing~~ indicative annual bills for typical customers in 2023–24 based on the draft notified prices, compared to annual bills using ~~the~~ current (2022–23) notified prices.

Importantly, an individual customer's actual bill will vary depending on how much electricity they use. We ~~strongly~~ recommend that customers engage with their retailer for further advice and information reflecting their individual circumstances.

Customers should note that the indicative bills do not include metering charges.[7]

~~It is relevant to note that increases in electricity prices (and the underlying energy costs) are not isolated to regional Queensland. For instance, the maximum price retailers in south-east Queensland could charge standing offer customers (the default market offer (DMO)) increased by 11.3 per cent in 2022–23.[8] Further impacts are likely to be felt more broadly in the coming year.~~

1.2.1 Residential customers

Typical customers on the main residential tariffs (tariffs 11, 31 and 33)[9] are expected to pay around X to X per cent more for their electricity in 2023–24.

Figure 1 Bills for typical residential customers, 2022–23 and 2023–24 (incl. GST)

Note: Amounts are rounded to the closest dollar. Therefore, amounts presented may not add precisely. Percentage changes are based on unrounded amounts. Metering costs are excluded.

[5] QCA, *SEQ retail electricity market monitoring 2021–22 report*, December 2022, p. 148.
[6] AEMO, *Quarterly energy dynamics Q2 2022*, 2022.
[7] This is to provide a like-for-like comparison with current notified prices. This year, the delegation asks us to include metering costs within the retail cost component of notified prices (in previous years, metering charges were separate to (and not included in) notified prices). See section 3.X for further detail.
~~[8] For residential customers without control load, compared to the default market offer price in 2021–22. AER, *Default market offer prices 2022–23*, final determination, May 2022, p. 7.~~
[9] Most residential customers are on tariff 11, but many customers also access load control tariffs—tariffs 31 and 33—for appliances that do not require a constant supply of electricity (e.g. hot water systems and pool pumps).

1.2.2 Small business customers

Typical customers on the main small business tariff (tariff 20)[10] are expected to pay around X per cent more for their electricity in 2023–24.

Figure 2 Bills for typical small business customers, 2022–23 and 2023–24 (incl. GST)

Note: Amounts are rounded to the closest dollar. Therefore, amounts presented may not add precisely. Percentage changes are based on unrounded amounts. Metering costs are excluded.

1.2.3 Large business customers

Typical customers on tariffs 44, 45 or 46 are expected to pay around X to X per cent more for their electricity in 2023–24.

Figure 3 Bills for typical large business customers, 2022–23 and 2023–24 (incl. GST)

Note: Amounts are rounded to the closest dollar. Therefore, amounts presented may not add precisely. Percentage changes are based on unrounded amounts. Metering costs are excluded.

[10] Tariff 20 is a flat-rate tariff.

Queensland Competition Authority

MEMORANDUM

TO: [redacted] **DATE:** 3/02/2023

FROM: [redacted] **CC:** [redacted]

SUBJECT: **Draft notified prices—Preliminary estimates as of 3 February 2023**

This paper provides an overview of the key preliminary estimates for draft notified prices as of 3 February 2023. Further adjustments may be made to:

- update the rate of inflation used to estimate retail costs (RBA's latest forecasts expected early Feb 2023)
- incorporate further changes stemming from our quality assurance process for the pricing model and energy cost analysis.

Indicative bill impacts

Overall, typical customers on all **major tariffs** can expect an **increase** in their bill based on the draft notified prices (Table 1). This increase is largely due to an **increase** in estimated **energy** and **network** costs.

Table 1 Change in annual bills for typical customers, 2022–23 and 2023–24 (incl. GST)

Tariff Class	*Retail Tariff*	*Change in annual bill from 2022–23 Final*	
		$/annum	*(%)*
Residential	Tariff 11	$404.07	27.8%
	Tariff 31	$35.02	12.6%
	Tariff 33	$33.24	11.5%
Small Business	Tariff 20	$469.91	25.2%
Large Business	Tariff 44	$6,191.32	12.2%
	Tariff 45	$22,259.60	13.0%
	Tariff 46	$10,959.37	5.7%

Energy costs

Energy costs for all customer groups are estimated to **increase**, primarily driven by higher wholesale energy costs (Table 2).

Table 2 Energy costs, 2022–23 and 2023–24 (excl. GST)

Customer group	*Main retail tariff*	*2022–23 Final*	*2023–24 Draft*	*Change from 2022–23 Final*	
		$/MWh		*$/MWh*	*%*
Energex (Small Customers)	Tariffs 11, 20	$125.01	$190.21	$65.20	52.2%
Energex CLP 9000	Tariff 31	$107.77	$126.77	$19.00	17.6%
Energex CLP 9100	Tariff 33	$113.09	$133.02	$19.93	17.6%
Ergon (Large Business)	Tariffs 44, 45, 46	$113.28	$146.65	$33.37	29.5%

Wholesale energy costs

The level of wholesale energy costs is determined by the prevailing market conditions in the NEM and relevant financial markets. Our approach in estimating wholesale energy costs is designed to closely reflect these market dynamics, which are best approximated by publicly available prices and traded volumes of ASX contracts.

In practice, retailers adopt a range of hedging strategies to manage spot price volatility within the NEM[1], including through the purchase of ASX contracts. Generally, the purchase of ASX contracts enables retailers to lock in a price, or a maximum price (in the case of cap contracts), at which a given volume of electricity will be transacted at a future date. Therefore, ASX contract prices incorporate market participants' expectations of future spot prices.

1.1.1 Key drivers

Compared last year's estimates, **wholesale energy costs** are estimated to **increase** for all customer groups (Table 3). These changes in costs reflect a significant **increase** in the **trade-weighted prices** for **ASX** base and cap **contracts** (Table 4). The increase in ASX contract prices is driven by market participants expecting higher future spot prices and greater price volatility, which is likely due to:

- higher gas and coal prices. Thermal generators have been facing higher fuel costs due to the war in Ukraine and energy sanctions imposed on Russia (a major global oil, gas and thermal coal producer). These developments have added further uncertainty to energy markets already impacted by global supply constraints[2] (due to the covid-19 pandemic), which led to high and volatile gas and thermal coal prices (Figures 1 and 2)
- uncertainties associated with the availability and reliability of coal-fired power plants and their impacts on the supply–demand balance in the Queensland NEM region. For example, Kogan Creek began a scheduled outage in September 2022 for a major overhaul and its return to service was delayed for more than a month due to unforeseen additional repairs required.[3] Further, Callide C (unit 3) suffered from a forced outage since October 2022. Callide C's operator (CS Energy) initially advised that the unit was expected to return to service in February 2023 but this timeframe was later revised to May 2023.[4] CS Energy also delayed the return of service of Callide C

[1] The NEM is a volatile market where spot prices are settled every 5 minutes and currently can range from –$1,000 to $15,500 per megawatt hour (MWh).
[2] See Bloomberg, Commodities soar as war builds anxiety over supply shortages, accessed in January 2023.
[3] See CS Energy, Kogan Creek power station overhaul extended, accessed in January 2023.
[4] See CS Energy, Updated return to service date for Callide C units, accessed in January 2023.

(unit 4) from April to May 2023.[5] These outages have reduced the average available capacity by around 864MW in Q4 2022.[6]

Our wholesale energy cost methodology also incorporates the potential impacts of temporary price caps for gas and coal, which were implemented by Commonwealth and Queensland Governments in December 2022 (see section 1.1.2 for more information).

Table 3 Wholesale energy costs, 2022–23 and 2023–24 (excl. GST)

Customer group	*Main retail tariff*	*2022–23 Final*	*2023–24 Draft*	*Change from 2022–23 Final*	
		$/MWh		*$/MWh*	*%*
Energex (Small Customers)	Tariffs 11, 20	$94.93	$157.99	$63.06	66.4%
Energex CLP 9000	Tariff 31	$78.80	$98.65	$19.85	25.2%
Energex CLP 9100	Tariff 33	$83.78	$104.49	$20.71	24.7%
Ergon (Large Business)	Tariffs 44, 45, 46	$84.61	$118.74	$34.13	40.3%

Table 4 Queensland trade-weighted ASX contract prices

Contract type	*Quarter*	*2022–23 Final*	*2023–24 Draft*	*Change from 2022–23 Final*	
		$/MWh		*$/MWh*	*%*
ASX base contract	Q3	$58.[illegible]	$102.26	$43.95	75.4%
	Q4	$59.[illegible]	$90.28	$30.52	51.1%
	Q1	$78.22	$114.08	$35.86	45.8%
	Q2	$57.43	$84.11	$26.68	46.5%
ASX cap contract	Q3	$13.32	$18.59	$5.27	39.6%
	Q4	$15.04	$21.67	$6.63	44.1%
	Q1	$29.53	$36.03	$6.50	22.0%
	Q2	$8.31	$14.72	$6.41	77.1%

Source: ASX Energy.

Note: To calculate the trade-weighted ASX contract prices for 2023–24 draft determination, we have used contract prices and volume of contracts and options traded until 20 January 2023 inclusive. Such an approach takes into account the most current information (including developments over the potentially volatile summer period), while still meeting our draft determination timeframe.

[5] Callide C (unit 4) has been unavailable since May 2021 following a major explosion. See CS Energy, Updated return to service date for Callide C units, accessed in January 2023.

[6] AEMO, Quarterly Energy Dynamics Q4 2022, January 2023.

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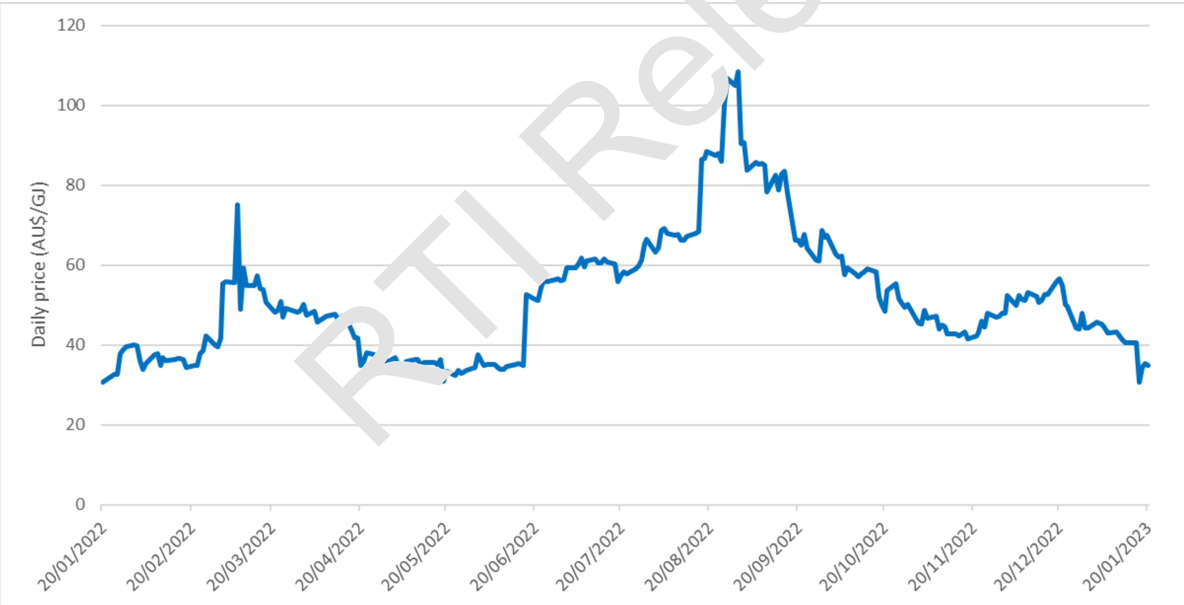
Date 3/02/2023

Figure 1 Newcastle thermal coal export prices

Source: Bloomberg Intercontinental Exchange (ICE).

Figure 2 Asian liquefied natural gas (LNG) prices



Source: Bloomberg Intercontinental Exchange (ICE).

1.1.2 Government intervention

In December 2022, the Australian Government partnered with the states and territories to introduce an Energy Relief Plan with measures to address high energy costs. Key aspects of this plan include temporary price caps for gas and coal, which are key input costs for thermal generators. Under this plan, wholesale gas and coal prices for electricity generation would effectively be capped at $12/GJ and $125/tonne respectively (for at least 12 months).

Our wholesale energy cost methodology captures the potential impacts of these caps through our spot price analysis and the incorporation of ASX contract prices (until 20 January 2023 inclusive). Importantly, the ASX contract prices reflect, to date, the market participants' views of the potential impacts of these temporary price caps on the

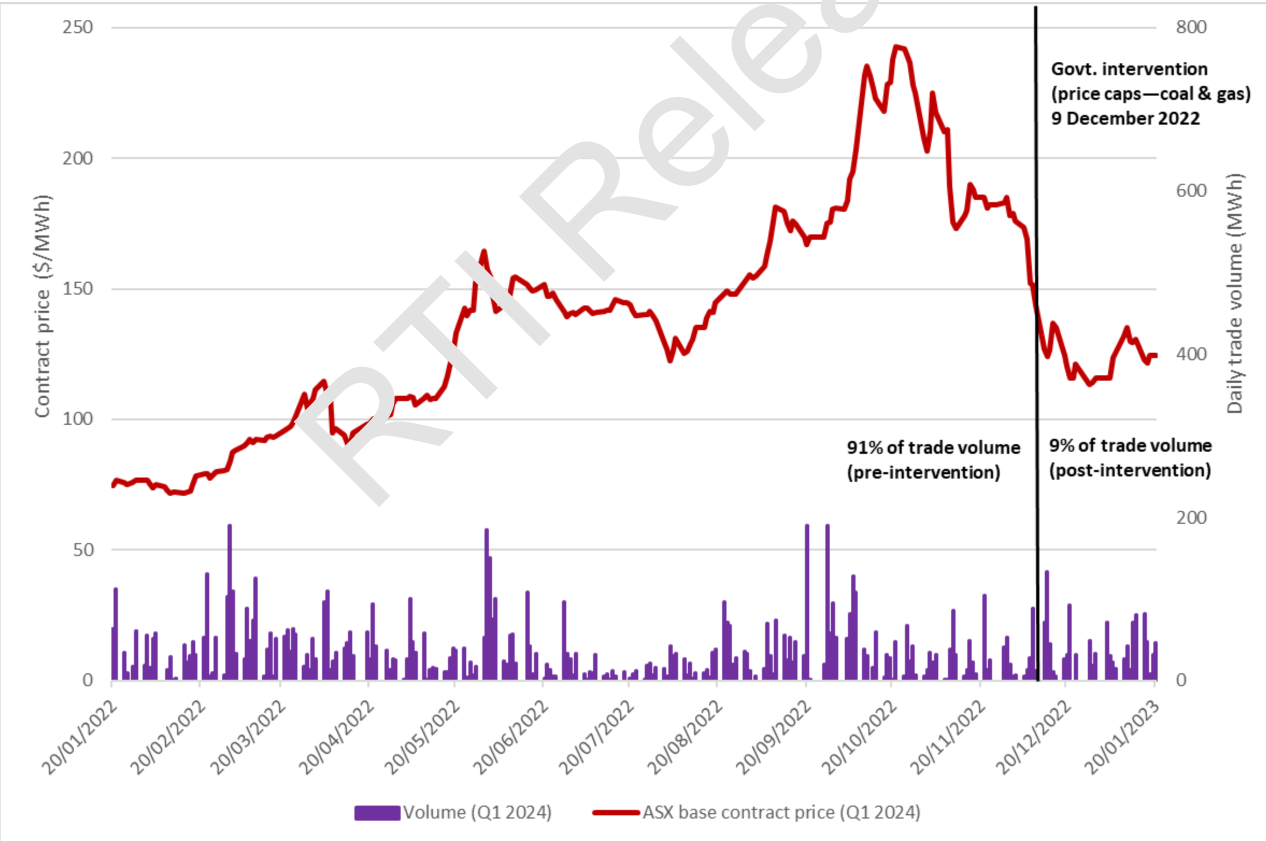
NEM. The potential effects of these caps are best illustrated using the price and trade movement of ASX base contracts for the summer quarter for 2023–24, i.e. Q1 2024 (Figure 3).

As shown in Figure 3, prior to the war in Ukraine intensifying in late February 2022, ASX base contract prices for Queensland (Q1 2024) averaged around $67/MWh. From then on, these contract prices have increased substantially, reaching a record high of approximately $243/MWh in late October 2022 before declining to around $150/MWh prior to the government intervention in early December 2022. Since the commencement of the temporary price caps, these contract prices have decreased further, fluctuating between $113/MWh and $137/MWh.

However it is important to note that, in practice, retailers manage their spot price risk by locking-in a price (or a maximum price[7]) in advance for part of their electricity requirements via trading in ASX contracts. In other words, retailers have already locked-in a portion of their costs for 2023–24 prior to the commencement of the temporary price caps. This market dynamic can be demonstrated using the movement in trade volume for the ASX base contracts (Q1 2024), where approximately 91% of the contracts traded were locked-in before commencement of the price caps. This means that only 9% of ASX contracts traded were influenced by the price caps (Figure 3).

It is expected that the temporary price caps would put downward pressure on the trade-weighted ASX contract prices (and in turn wholesale energy costs) as more ASX contracts are traded while the price caps are in force. For our final determination, we will use ASX data until late April/early May 2023 to estimate contract prices.

Figure 3 Queensland ASX base contract 2023–24 (Q1 2024)



Source: ASX Energy and QCA analysis.

[7] Retailers can lock in the maximum price for future electricity purchases by trading in ASX cap contracts.

1.1.3 Methodological refinement—wholesale energy costs

To better reflect the latest market developments, we have also refined our wholesale energy cost methodology by:

- incorporating demand profiles of smart meters to better approximate the consumption pattern of electricity. Since the introduction of the AEMC's Power of Choice reforms[8] in 2017, installations of new rooftop solar PV would involve an upgrade of meters (from accumulation to smart meters). This means that the demand profiles based on only accumulation meters (i.e. the net system load profiles (NSLPs)) would likely misrepresent the consumption pattern of electricity. This is because the reduction in day-time demand due new rooftop PV output would be captured by smart meters instead of accumulation meters (and by extension the NSLPs).

  To address this issue, we have combined the relevant smart meter profiles with the NSLPs when estimating wholesale energy costs. This is consistent with what retailers do, in practice, when developing their hedging strategies. Based on informal discussions, retailers in south east Queensland advised that they would not distinguish between customers with different meter types but would combine the profiles for smart and accumulation meters (for a specific customer group) when undertaking hedging activities.

- improving our estimation of the costs that retailers faced when trading in ASX options to manage spot price volatility. Our initial approach to estimating ASX contract prices includes options traded by using a simplified approach, where options were approximated using the volume of options traded and ASX daily settlement prices for base contracts.

  However, recent market volatility has prompted us to consider refining this approach. To reflect the costs of trading in options more accurately, we have incorporated the

  – strike prices of call options[9] exercised

  – premiums of call options exercised and expired

  – trade volume of call options exercised and expired.

Other energy costs

Compared to the estimates from last year, we estimated that:

- **LRET costs** would **increase**—driven by an increase in the forward prices of large-scale generation certificates due to higher voluntary demand for these certificates
- **SRES costs** would **decline**—driven by a decline in the estimated number of small-scale technology certificates retailers are required to purchase
- **NEM fees** would **increase**—reflecting an increase in costs related to operating the NEM, including the costs associated with the five-minute settlement reform and the integration of distributed energy resources
- **ancillary services charges** would **decrease**—due to lower costs for frequency control ancillary services (FCAS) in Queensland. The completion of upgrades for the Queensland to New South Wales interconnector (QNI) in June 2022 has reduced the need for local supply of FCAS in Queensland.

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[8] As part of this reform, the AEMC implemented rule changes to facilitate a market-led deployment of smart meters across the NEM. Among other things, these rule changes required that, from 1 December 2017, all new and replacement meters for small customers to be smart meters.

[9] In this context, call options are a type of financial derivative that gives the holder the right, but not the obligation, to purchase ASX base contracts at a predetermined price (known as the "strike price") and volume. In exchange for the right to exercise the option, the holder (buyer) will pay a premium to the seller of the call option (regardless of whether the holder chooses to exercise the option).

- **prudential costs** for **small customers** would **increase**—driven by elevated contract prices, greater expected price volatility in the NEM and the shape of the relevant demand profile becoming 'peakier' (due to a due to a substantial uptake of rooftop solar PV, which decreased daytime demand but had limited effect on the evening peak demand)
- **prudential costs** for **large customers** would **decrease**—primarily due to the shape of the relevant demand profile becoming 'flatter' (with more electricity consumed during the off-peak daytime period, instead of during the evening peak period)
- **Reliability and Emergency Reserve Trader (RERT) costs** would **decline**—driven by fewer activations of the RERT to assist with power system management (excluding RERT activations during events in June 2022, see June 2022 events)

We have also estimated the costs associated with **market events in June 2022** using the latest data from the AEMC and AEMO. These include the RERT costs and compensation costs published by the AEMC and AEMO to date. The compensation costs are in relation to the trigger of the administered price cap and suspension of the wholesale market by AEMO (from 15 to 24 June 2022).

Table 5 Other energy costs, 2022–23 and 2023–24 (excl. GST)

Cost component	*2022–23 Final*	*2023–24 Draft*	*Change from 2022–23 Final*	
	$/MWh		*$/MWh*	*%*
Large-scale Renewable Energy Target (LRET)	$5.00	$7.19	$2.19	43.8%
Small-scale Renewable Energy Scheme (SRES)	$10.90	$6.86	–$4.04	–37.1%
NEM Fees	$1.13	$1.15	$0.02	1.8%
Ancillary Services	$1.42	$0.60	–$0.82	–57.7%
Prudential Capital (Small customers)	$2.55	$3.24	$0.69	27.1%
Prudential Capital (Large customers)	$2.10	$2.00	–$0.10	–4.8%
Reliability and Emergency Reserve Trader (RERT)	$1.01	$0.01	–$1.00	–99.0%
June 2022 market events	$0.00	$0.89	$0.89	—

Network costs

Network costs were estimated using the draft network prices provided by Energy Queensland (EQ) in December 2022. EQ advised that the draft prices are subject to change, noting that, prior to submitting its pricing proposals to the AER in March 2023, it would:

- update its annual revenue requirements to reflect additional actual data as they become available, including the rate of inflation, weighted average cost of capital and X-factor.
- incorporate financial rewards or penalties stemming from the AER's Service Target Performance Incentive Scheme (STPIS)
- update the transmission charges and jurisdictional scheme payments (i.e. recovery for the Solar Bonus Scheme)
- update its energy volume forecasts used to derive network prices.

Compared to last year's estimates, draft network prices have **increased** for most **main tariffs** for both small and large customers but **declined** for the **load control tariffs** (Tables 6 and 7).

Table 6 Network charges, 2022–23 and 2023–24 (excl. GST)

Tariff	*Charging parameter*	*Unit*	*2022–23 Final*	*2023–24 Draft*	*Change from 2022–23 Final*	
					Unit	*%*
Tariff 11	Fixed charge	$/day	0.516	0.550	0.034	6.6%
	Volume	$/kWh	0.074	0.079	0.004	5.9%
Tariff 31 (load control)	Volume	$/kWh	0.034	0.033	–0.0004	–1.2%
Tariff 33 (load control)	Volume	$/kWh	0.044	0.042	–0.001	–2.8%
Tariff 20	Fixed charge	$/day	0.690	0.730	0.040	5.8%
	Volume	$/kWh	0.082	0.083	0.001	1.5%
Tariff 44	Fixed charge	$/day	37.650	38.485	0.835	2.2%
	Demand	$/kW/month	22.784	24.592	1.808	7.9%
	Volume	$/kWh	0.026	0.023	–0.003	–10.9%
Tariff 45	Fixed charge	$/day	124.576	125.237	0.661	0.5%
	Demand	$/kW/month	21.821	24.592	2.771	12.7%
	Volume	$/kWh	0.026	0.023	–0.003	–10.9%
Tariff 46	Fixed charge	$/day	325.604	326.544	0.940	0.3%
	Demand	$/kW/month	17.874	19.585	1.711	9.6%
	Volume	$/kWh	0.026	0.023	–0.003	–10.9%

Table 7 Network costs, 2022–23 and 2023–24 (excl. GST)

Retail Tariff	*2022–23 Final*	*2023–24 Draft*	*Change from 2022–23 Final*	
	Annual bill ($)		*$*	*%*
Tariff 11	$520.75	$552.70	$31.94	6.1%
Tariff 31	$54.48	$53.80	–$0.68	–1.2%
Tariff 33	$66.13	$64.29	–$1.85	–2.8%
Tariff 20	$651.91	$672.39	$20.48	3.1%
Tariff 44	$25,678.88	$26,175.41	$496.53	1.9%
Tariff 45	$81,710.20	$83,065.30	$1,355.09	1.7%
Tariff 46	$129,068.34	$128,785.76	–$282.59	–0.2%

Retail costs

Retail costs were estimated using the cost estimates derived in our 2021–22 determination, using a benchmarking approach. Given the recency of the retail cost review, we:

- adjusted the fixed retail costs using the RBA's latest forecast change in the rate of inflation for 2023–24 (4.25%)—to maintain the fixed costs in real terms. As noted, we expect to update this estimate in early Feb 2023 when the RBA updates its forecasts
- maintained the variable retail cost allocators—at 7.25% for residential customers, 18.7% for small business customers and 6.04% for large business customers.

Retail costs were estimated to increase—reflecting the rate of inflation, higher energy costs and variable network costs. Higher energy and variable network costs have increased the value of variable retail costs.

Table 8 Retail costs, 2022–23 and 2023–24 (excl. GST)

Retail Tariff	***2022–23 Final***	***2023–24 Draft***	***Change from 2022–23 Final***	
	Annual bill ($)		***$***	***%***
Tariff 11	$213.98	$245.47	$30.86	14.4%
Tariff 31	$18.24	$20.86	$2.39	13.1%
Tariff 33	$18.92	$21.39	$2.[illegible]5	11.9%
Tariff 20	$407.92	$484.95	$75.25	18.4%
Tariff 44	$3,571.97	$4,0[illegible].74	$420.75	11.8%
Tariff 45	$11,129.85	$12,70[illegible].45	$1,513.21	13.6%
Tariff 46	$14,296.00	$15,432.63	$1,101.56	7.7%

Standing offer adjustment

Using the same methodology and latest fees and charges published in our SEQ market monitoring report, the standing offer adjustment was estimated to increase by 0.86% to 4.56%, compared with last year's estimate of 3.7%.

Cost pass-through

Based on latest data from the Clean Energy Regulator, our analysis found that the estimated number of small-scale technology certificates that retailers are required to purchase is lower than initially estimated. This has led to an over-recovery of SRES costs in 2022–23 and therefore a negative cost pass-through (Table 9).

Table 9 SRES cost pass-through (excl. GST)

Retail Tariff	***2023–24 Draft***
	c/kWh
Tariff 11	–0.284
Tariff 31	–0.284
Tariff 33	–0.284
Tariff 20	–0.314
Tariff 44	–0.270
Tariff 45	–0.270
Tariff 46	–0.270

END OF PAPER.

Agenda Topic: ENERGY

Section 73 - Irrelevant Information

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6. The increase in the annual bill is largely due to:

(a) an increase in wholesale energy costs—including a significant increase in the trade-weighted prices for ASX base and cap contracts, driven by market participants expecting higher future spot prices and greater price volatility. This is likely due to higher gas and coal prices and uncertainties associated with the availability and reliability of coal-fired power plants impacting the supply–demand balance in the Queensland NEM region

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Queensland Competition Authority

DECISION

Agenda Topic: ENERGY

Draft determination: notified electricity prices for regional Queensland in 2023–24

RECOMMENDATION

It is recommended that Members approve:

1 **publishing the draft determinations and associated material (Attachments 1 to 6)**

2 **providing stakeholders with around four weeks to make submissions**

3 **authorising the CEO to approve final editorial changes to the relevant documents before publication.**

BACKGROUND

1. On 15 December 2022, we received:

    (a) Ministerial delegations to set notified prices and two new time-of-use (TOU) tariffs for regional Queensland in 2023–24. We published the interim consultation paper the following day and received six stakeholder submissions (due by 18 January 2023), which have been considered in preparing the draft determination (submissions have also been uploaded to Diligent for Members to view)

    (b) a Ministerial direction to set the solar feed-in tariff for regional Queensland in 2023–24. We published the direction and advised stakeholders we would consult with them in due course (as required by the direction) (see separate board paper).

2. At the February meeting, Members were provided an update on the notified prices review, including preliminary estimates of draft notified prices and expected bill impacts.

3. On 17 February 2023, we received amended delegations that require us to publish the draft determinations contemporaneous with the AER's draft SEQ default market offer (DMO) decision (rather than by February). The AER is expected to publish its decision in the week of 13 March. The deadline for the final determination remains unchanged at 9 June.

4. The notified prices draft determination material provided for Members' review comprises:

    (a) the report (**Attachment 1**)

    (b) the consultant's report on energy costs (**Attachment 2**)

    (c) the information booklet accompanying the draft determination (**Attachment 3**)

    (d) relevant correspondence, including a media release and letter to the Minister (a version of this letter will also be sent to the Premier and Treasurer) (**Attachments 4 and 5**)

    (e) the technical appendices to the draft report (**Attachment 6**).

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5. The remainder of this paper briefly summarises price outcomes and key matters referenced in the draft determinations.

KEY ISSUES

Notified prices—draft determination

6. Overall, the draft prices result in an increase in typical customers' annual bills this year:

Customer type	*Tariff*	*Expected increase from 2022–23*	
		Amount	*Percentage*
Residential	11	$432	28.9%
	31	$36	12.3%
	33	$34	11.3%
Small business	20	$497	26.1%
Large business	44	$6,179	12.2%
	45	$22,226	13.0%
	46	$10,874	5.6%

7. These prices are materially consistent with those provided to Members at the February board meeting, with some differences due to the addition of metering costs in small customer draft prices and bills[1] and further internal review/quality assurance processes.

8. The increase in prices reflects:

(a) a significant increase in wholesale energy costs—due to a significant increase in the trade-weighted prices for ASX base and cap contracts (discussed in chapter 4.2.1 of the draft report)

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Queensland Competition Authority

DECISION

Agenda Topic: ENERGY

Final determination of notified prices for 2023–24

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KEY ISSUES

5. Overall, the final notified prices result in an expected increase in typical customers' annual bills this year, compared to last year. Notified price increases are also higher than in the draft determination, largely due

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to a further increase in the wholesale energy cost estimates since then (reflecting more up-to-date market data).

Table 1 Change in indicative bills for main tariffs

Customer type	*Tariff*	*Draft determination (compared to last year's final prices)*	*Final determination (compared to last year's final prices)*	*Difference between draft and final determinations*
Residential	11	28.9%	34.6%	5.7%
Small business	20	26.1%	32.6%	6.5%
Large business	44	12.2%	15.6%	3.4%
	45	13.0%	16.7%	3.7%
	46	5.6%	7.5%	1.9%

Note: Tariff 11 and 20 prices are inclusive of a standing offer adjustment (SOA) of 4.56%—this amount may be reduced in the final determination depending on the results of the DMO comparison.

6. The key issues in the final determination are the following:

(a) Significant price increases:

(i) We have provided commentary on the resources available to customers to deal with the electricity price increases (section 3.1 of the main report).

(ii) We have provided a detailed discussion on the rising energy costs contributing to the significant notified price increases (section 4.2.1 of the main report). The incorporation of updated market data since the draft determination has contributed to increases in the wholesale energy costs. This includes the use of additional ASX contract data (up until 10 May 2023), with contract prices remaining elevated compared to previous years. ACIL has also incorporated more recent information on generator bidding behaviour in response to the coal and gas price caps, which has also contributed to the higher wholesale energy costs.

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QUESTION AND ANSWER SPEAKING NOTES

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1.1 Media handling responses

- If asked by journalists whether they can film the session

  We ask that you respect attendees' and our own privacy and do not film and broadcast the information session. This session is intended to inform members of the public here today and we don't want the presence of cameras to affect proceedings or make attendees feel uncomfortable.

  If you want official comments or an interview with the QCA's official spokesperson, we can give you the contact details of a colleague at the QCA who can liaise with you on this. [Give Sharon's details]

- If asked by journalists to provide official comments or quotes

  We cannot provide official comments or quotes, as we do not have the authority to represent the QCA. The QCA's official spokesperson is its chair, Professor Flavio Menezes. If you are after formal comments from the QCA, we can give you the contact details of one of our colleagues at the QCA who can deal with your request. [Give Sharon's details]

1.2 Legal framework questions

- Why does the QCA just do what the Minister tells you to do?

  The QCA is there to put in place the rules that have been developed by the Government of the day.

  For our role in setting regulated prices, we perform this role under the Electricity Act via a delegation issued to us by the Electricity Minister. So it's a power that sits with the Minister, who then delegates it to us to perform for that year. The Electricity Act sets out several factors we must consider when making a determination. We must also have regard to various matters the Minister states in his delegation to us, which includes things such as applying the 'n+r approach' and the Queensland Government's UTP.

- The QCA is not complying with the terms of the QCA Act

  The QCA performs various regulatory roles for electricity, water, rail and ports in terms of the prices regulated entities are able to charge. We perform these roles under the QCA Act and in other legislation, such as the Electricity Act.

  For our role here setting regulated retail electricity prices, we perform this role under the Electricity Act via a delegation issued to us by the Energy Minister.

  Some stakeholders have referred to us not following certain sections of the QCA Act. However, these do not apply here to our setting of notified prices. Those sections of the QCA Act apply to the QCA's prices oversight regime, which is a completely different regulatory regime. Some stakeholders may recognise it from our water pricing investigations. That regime involves us being directed by the Treasurer to investigate and recommend prices for declared monopoly businesses. It is a recommendatory price regime and not a price determination regime, like our role in setting notified prices.

1.3 Price outcomes / Affordability / UTP questions

- Why are electricity prices rising so much this year?

The main cause of these price increases is higher wholesale energy costs. That is, the cost for a retailer when purchasing electricity for their customers from the National Electricity Market. For instance, energy costs for the main residential and small business tariffs (tariffs 11 and 20) have increased approximately 50 per cent compared to last year.

The increase in wholesale energy costs has been driven by:

- higher gas and coal prices, primarily due to the war in Ukraine and energy sanctions imposed on Russia, which has added further uncertainty to energy markets already impacted by global supply constraints.
- uncertainties associated with the availability and reliability of coal-fired power plants and their impacts on the supply–demand balance.

In addition, there has also been higher retail and network costs for most tariffs this year.

- Does the QCA take affordability into account when setting electricity prices?

We must make our determination of electricity prices in accordance with the legislative framework. This is set out in the Electricity Act and in matters the Minister requires us to consider. Ultimately, we set electricity prices based on the costs of supplying electricity to customers in a given year.

The lever we can apply that helps with affordability is the Queensland Government's uniform tariff policy (UTP). For residential and small business customers, this means that prices are based on electricity supply costs in southeast Queensland, which is less than the actual cost of supply. As such, the UTP delivers lower electricity prices than would otherwise be the case to most customers in regional Queensland. The UTP results in the Queensland Government subsidising regional electricity prices—in 2022–23, this was expected to total $568 million.

However, we appreciate this does not shield customers from underlying price increases caused by increased market volatility and higher energy costs, which have been prevalent in the NEM, including in southeast Queensland.

- What is the UTP?

The uniform tariff policy (UTP) is a Queensland Government policy. It provides that, wherever possible, customers of the same class should pay no more for their electricity, and should pay for their electricity via similar price structures, regardless of their geographic location.

This means:

- for small customers, costs are based on the costs of supply in SEQ, which are lower than the costs of supply in regional Queensland.
- for large customers, costs are based on the cost of supply in the Ergon region with the lowest cost of supply that is connected to the NEM.

This results in most customers in regional Queensland paying electricity prices which are below the costs of supplying them with electricity. The cost difference is met by the Queensland Government through a payment to Ergon Energy Queensland (expected to be $568 million in 2022–23).

- Why won't the QCA change the UTP to improve competition in the retail market?

We understand stakeholders have views about reforms that should be made to the UTP. However, the UTP is a Queensland Government policy and can only be changed by the government.

Our task is to set electricity prices in accordance with the legislative framework. Assessing the UTP and exploring potential reforms to address affordability or competition concerns is not within our remit.

We encourage stakeholders seeking changes to the UTP to raise these with the Queensland Government, as it is their policy and they ultimately have the power to have it reviewed.

- These prices are too high and we cannot pay them

We understand these price increases are quite significant for customers.

However, we must make our determination of electricity prices in accordance with the legislative framework. This is set out in the Electricity Act and in matters the Minister requires us to consider. Ultimately, we set electricity prices based on the costs of supplying electricity to customers in a given year. These costs have increased significantly this year. However, we have applied the Queensland Government's uniform tariff policy. If we had not done this, prices would have been even higher.

We do recognise these increases will come as a shock for customers.

The Australian Government has partnered with states and territories to introduce an Energy Price Relief plan, which includes targeted bill assistance measures that will reduce an eligible customer's electricity bill. At this stage, the details are still being worked out by the Australian and Queensland Governments. This is something that sits outside of the QCA's price setting process so we can't provide any comments on that.

We encourage any customers facing hardship to contact their retailer to discuss support measures that may be available to them. There are a range of government support arrangements, including concessions, grants and rebates, that are available to eligible customers. Each retailer will also have a customer hardship program that can help customers who are having difficulties paying their bill. The retailer can also give you advice on whether you are on the tariff most suitable for your circumstances.

Alternatively, there is a Queensland Government website that can help you find any concessions or other support measures you might be eligible for (https://www.concessionsfinder.services.qld.gov.au/#/).

- The QCA should provide more affordable prices to business / we cannot operate or compete with these prices

We understand these price increases are significant. However, the legislative framework requires us to take a cost-based approach to setting notified prices. We cannot apply measures to lower prices for particular businesses or industries, other than applying the Queensland Government's uniform tariff policy.

The uniform tariff policy makes electricity prices for most regional Queensland customers cheaper than what they otherwise would be. It involves the Queensland Government subsidising electricity prices – which was expected to cost $568 million in 2022–23.

Further measures to address affordability concerns are best achieved through more targeted direct measures, such as grants, concessions or rebates. Industry assistance is a policy and state budget matter for the Queensland Government. It is not something the QCA can provide.

We encourage businesses or industry representative groups seeking industry assistance to reach out to the Queensland Government.

- How do I find out what support arrangements / concessions are available to me?

You can contact your retailer who can discuss with you what support arrangements are available for you. Alternatively, there is a Queensland Government website that can help you find any concessions or other support measures you might be eligible for (https://www.concessionsfinder.services.qld.gov.au/#/).

- Ergon is inefficient. More should be done to bring costs down

The regulated prices we set comprise several different cost components, the main two being network costs and retail costs.

Network costs are made up of the network prices that are approved by the AER. So these are subject to scrutiny by that regulator. We pass these through to retail tariffs, as they are costs a retailer incurs providing you with your electricity.

Retail costs are determined by us. There are a range of retail costs that we determine, including costs for customers services, like call centres and administration such as billing services. It also includes energy costs, being the costs for a retailer to buy electricity from the national electricity market. We include in our determination details on how we determine these costs. But I will note these costs are based on competitive markets – either the purchase of energy futures contracts in the case of energy costs and in a benchmarking exercise in the case of retail costs. Its not the case that we simply pass through a retailer's actual costs.

Overlaying all of this of course, is that we apply the Queensland Government's uniform tariff policy. This means that for most customers in regional Queensland, the costs we determine are based on the actual costs of supply for your geographic area, but are instead based on a lower cost area, such as southeast Queensland or the lowest cost Ergon area connected to the NEM. The Queensland Government subsidises the difference in costs.

1.4 Wholesale energy cost

1.4.1 What effect have the government price caps on gas and coal prices had?

We capture the potential impacts of these price caps through the way we calculate the wholesale energy costs. Both in our analysis of spot prices in the electricity market and the trade in ASX energy futures contracts, which we use to calculate how retailers have hedged their exposure to spot prices.

We have observed some downward movement on the relevant ASX futures contract prices. We go into detail about these observations in our draft determination. However, it is important to note that, in practice, retailers manage their spot price risk by locking-in a price in advance for part of their electricity requirements by entering into hedging contracts. So retailers would have already locked-in some of their costs for 2023–24 prior to the commencement of the price caps.

We expect to see further effects of the price caps in our final determination, as we will have more ASX market data while the price caps are in force that we will use when setting notified prices.

- Use Figure 6 chart for slide

For background—in December 2022, the Australian Government partnered with the states and territories to introduce an Energy Relief Plan with measures to address high energy costs. This includes temporary price caps for gas and coal, which are key input costs for thermal generators. The cap is $12/GJ for gas and $125/t for coal.

1.4.2 The QCA report said that outages at coal fired power plants were to blame for increased energy costs. Does that mean we need more coal-fired base load power generation?

Increased outages in coal fired power plants led to a lower supply-demand balance in the NEM. This does not necessarily mean that more coal-fired base power generation is needed. Increasing the supply demand balance by alternative, low coast means can also help put downward pressure on electricity prices.

1.4.3 What is 'hedging'?

Retailers purchase electricity for their customers through the national electricity market (the NEM). This is a very volatile market where spot prices are settled every five minutes and can range from -$1,000 to $15,500.

Retailers adopt a range of strategies to manage (or hedge against) the risk of spot price volatility. For example, retailers buy ASX energy futures contracts and other products to 'lock-in' a price for electricity that they will deliver to consumers at a fixed price at a later date.

1.4.4 If retailers locked in higher energy prices, why should customers have to pay for that?

Our wholesale energy cost methodology is based on the hedged cost of a retailer purchasing electricity in the NEM. Hedging is a prudent strategy that manages a retailer's risk to volatile spot prices. As such it is reasonable for retailers to be compensated for these costs.

1.4.5 Will the government's intervention cause energy costs to drop in the final determination

From draft determination to final determination, amongst other things, we will incorporate more market data relating to ASX energy futures contracts. This data could put either upward or downward pressure on energy costs, depending on the price of traded contracts.

1.4.6 Why does the QCA's estimate of energy costs differ from the AER's?

Differences between our estimate of energy costs and the AER's are largely due to methodological differences. As part of this year's determination, we have incorporated digital meter data to estimate energy costs, whereas the AER has not. Additionally, we adopt a more conservative estimate of the costs that a retailer faces (95th versus 75th percentile) when purchasing electricity from the NEM.

1.4.7 We get told that renewables are meant to lower energy costs so why have they gone up so much if the amount of renewables has increased over the last year?

While the amount of renewable generation has increased in the Queensland, renewable generation from wind and solar generally bid into the market at low prices and are typically not price setting generators in Queensland. Gas and coal fired generators are more likely to be price setting generators. Due to the ongoing conflict in Ukraine, the price of coal and gas has increased, which has led to increased costs for these generators. This has meant that coal and gas fired generators have bid into the market at higher prices, resulting in higher energy costs.

1.5 Availability of tariffs

1.5.1 Obsolete tariffs—my tariff is obsolete, what do I do?

An obsolete tariff means it has been closed to new customers. Existing customers on the tariff can continue to access it until they change to another tariff or the obsolete tariff's phase-out date is reached. Obsolete tariffs are intended to allow a customer to consider their options and transition to another tariff.

If you are on an obsolete tariff, you should consider other tariffs available to you and contact your retailer to choose another tariff. If you do not choose another tariff before the phase-out date, you will be assigned by your retailer to another tariff.

1.5.2 Obsolete tariffs—what is the phase-out date for my tariff?

The phase-out date for most remaining obsolete tariffs is 30 June 2023.

Some tariffs (tariffs 50, 62A, 65A and 66A) do not have a confirmed phase-out date as it is unclear when the underlying network tariffs will be phased out. These tariffs will remain until 2025 when the next set of network tariffs will be set. A decision on the phase-out date for these tariffs will be made in future.

You should contact your retailer to confirm what tariff you are on and its scheduled phase-out date.

1.5.3 Obsolete tariffs—tariffs 62A, 65A and 66A have different peak charging windows to the other tariffs. They should be changed so they are the same

Due to recent tariff reforms, there is more consistency in peak charging windows between standard retail tariffs.

The obsolete tariffs have different charging windows because they reflect their original tariff structure. These tariffs have been preserved as a legacy tariff to give customers time to assess their options and ultimately help them transition to standard tariffs.

If you want access to those other charging windows, I encourage you to talk to your retailer and consider your options under the other tariffs.

1.5.4 Why won't the QCA introduce a food, fibre and manufacturing tariff / large customer consumption tariff?

In making our determination, we apply the 'n+r framework'. This means we pass through network tariffs to the retail-level. All of the standard retail tariffs are based on network tariffs developed by the distribution businesses, and approved by the Australian Energy Retailer. We do not create retail tariffs that have no underlying network tariff. This ensures that retail tariffs reflect the underlying network costs and that the price signals in network tariffs are passed through to retail customers.

More broadly, tariff reforms are based on developing tariffs that are cost-reflective and provide efficient price signals to customers. Standard tariffs are also broad-based and not targeted toward specific industries or business types.

1.5.5 Why won't the QCA introduce an affordable tariff that caps charges at 16c per kWh?

The prices we set are cost-reflective. They reflect both the network costs approved by the Australian Energy Regulator, and the retail costs, including wholesale energy costs, determined by us.

The 16c tariff that some stakeholders are proposing would not be cost-reflective. If stakeholders are seeking assistance for particular industries, this is best achieved through grants, rebates and other support arrangements provided by government, rather than through the design of special purpose or arbitrarily capped electricity tariffs.

1.5.6 Why won't the QCA lower the large customer consumption threshold?

In Queensland, business customers with annual consumption over 100 MWh are classified as large customers. This threshold is set in legislation—being the National Energy Retail Law and associated regulations.[1]

To change the threshold would require the legislation to be amended. The QCA does not have the power to do that. This is a matter for the Queensland Government.

Regardless of that, changes to the large customer threshold is a policy issue that would require consideration of a range of matters, including how changes in tariff eligibility for higher consumption customers could impact the network. This is something best considered in its own process.

1.6 Standing offer adjustment / default market offer

1.6.1 What is the standing offer adjustment?

As part of our determination, we have to consider incorporating a standing offer adjustment in electricity prices for small customers. This is meant to reflect the more favourable terms and conditions that apply in standard contracts compared to market contracts. For instance, customers on standard contracts can avoid fees and charges that are included in market contracts, such as paper bill fees and late payment fees. In addition, retailers cannot change the terms (and prices) for standard contract customers as they can with market contract customers, which provides more certainty and predictability to standard contract customers.

We use the fees that small customers in SEQ on market contracts could incur, and which that cannot be incurred by a standard contract customer, as a proxy for the value of the standing offer adjustment. This year, that amount of avoided fees and charges is $59 and equates to 4.56 per cent of a small customer's annual electricity bill.

Customers should note the standing offer adjustment may be lowered if the prices we set are higher than the Australian Energy Regulator's default market offer. We will perform that analysis in our final determination.

For background:

This year's standing offer adjustment is higher than the 3.7 per cent incorporated into notified prices last year. The difference is $7 or 0.86 percentage points.

[1] Section 7 of the National Energy Retail Regulations. Queensland, NSW and ACT use this threshold. SA and Tasmania have legislated different consumption thresholds (160 MWh and 150 MWh, respectively).

1.6.2 What is the AER's default market offer?

The default market offer (or DMO) is the maximum price that retailers can charge electricity customers on standing offer contracts. The AER determines this each year and it applies to residential and small business customers in areas where there is no retail price regulation, such as south-east Queensland. The DMO does not apply in regional Queensland, as we (the QCA) regulate retail prices in regional Queensland.

1.6.3 How does the AER's default market offer relate to the QCA's determination? / What is the DMO comparison?

The DMO only applies in areas where there is no retail price regulation, so it doesn't apply in regional Queensland.

However, the Minister's delegation asks us to compare the notified price bill to the equivalent DMO reference bill in south-east Queensland. If our price bill exceeds the DMO bill, we must consider reducing the standing offer adjustment we include in notified prices.

As we have been required to release our draft determination around the same time as the AER's draft DMO decision, we have not been able to do the DMO comparison yet. We will do this in our final determination.

1.6.4 Why haven't we done the DMO comparison?

We are required to release our draft determination around the same time as the AER released its draft DMO decision. As such, we did not have time to do the DMO comparison. We will do the DMO comparison in our final determination.

1.7 Metering costs for small customers

1.7.1 Will I pay more now?

This year, all small customers will pay the same as the Minister requested. As ADM costs are included, proportional to the number of customers on ADMs, metering costs will be higher. Type 6 metering costs (draft ACS metering services costs) for Energex are 11.552 cents/day, while the new draft charge for all customers will be 17.59 cents/day—that is, 6.04 cents/day more ($22.06 per year).

1.7.2 Will I pay double if I have a controlled load tariff?

Customers who are on a tariff that combines a primary tariff with a secondary tariff will not pay twice as much. ADM costs are included in the metering costs for the primary tariff, and as such, all customers will have the same metering costs for the primary tariff. The costs of the secondary tariff are based on the ACS metering services charge.

1.7.3 Why do I need to pay for customers with an ADM?

The Queensland Government is rapidly advancing its rollout of ADMs. Previously, metering charges for small customers with ADMS were based on the cost of standard (type 6) meters in SEQ. As more and more customers have an ADM, the Minister asked us to consider how to enable retailers to recover costs associated with the provision of all metering services. As customers do not choose which meter they have (e.g. old and faulty meters will get replaced by an ADM) the Minister considered it important that this is done in a fair and equitable way so that similar customers do not pay different amounts simply based on the type of meter they have.

1.7.4 How were the new metering costs calculated?

The direction requires us to base small customer retail metering service costs on:

- the Energex rate for standard Type 6 small customer metering services
- plus costs incurred by retailers operating in the Energex distribution area for small customer ADM services

while having regard to the rate of replacement of distributor meters with ADMs.

We sourced the required data:

- forecast ADM replacement rate assumptions for 2023–24 in regional Queensland (EQ)
- ADM costs used for the 2022–23 DMO determination (published AER final determination)
- draft ACS metering service charges for type 6 meters in the Energex distribution area (EQ).

We calculated weighted costs by multiplying the expected share of customers with ADMs (forecast ADM replacement rate) with the ADM costs the AER used for its 2022–23 DMO determination (which we adjusted for inflation up to 2023–24). To this we added the following: the share of customers with type 6 meters (calculated as '1 – share of customers with ADMs') multiplied by the draft ACS metering service charges for the Energex distribution area.

It is important to note that we will use updated data and information for our final determination.

1.7.5 How many customers have an ADM?

*** confidential information used *** Use info from Ergon Energy Retail submission instead:

'EEQ is committed to the deployment of digital meters in regional Queensland with ~34% of our National Meter Identifiers (NMIs) now having a digital meter installed, and a commitment to increasing our installation rates.'

The share during 2023–24 is expected to be higher, as the rollout of ADMS continues. The Queensland Energy and Jobs Plan sets a target of 100% penetration of smart meters by 2030.

[CONFIDENTIAL: We have used forecasts provided by Energy Queensland (42%)—that is, forecast digital meter replacement rate assumptions for 2023–24 that were used for the purpose of setting the draft 2023–24 network tariffs.]

1.7.6 Do I need to get an ADM?

Metering costs will be the same for basic meters and for ADMs. There are detailed provisions in the national energy rules that determine what meters can be used. But generally speaking, all new and replacement meters will be digital advanced meters.

1.8 Metering type 4A surcharge

1.8.1 Why will there be another charge?

ADMs are generally read remotely, which is more convenient and more cost-effective. However, some customers have voluntarily chosen to have the remote communication function of the ADM installed at their premises disabled. Reading such meters (referred to as type 4A meters) is more costly as they need to be read manually. The Minister explained in his covering letter that setting a retail fee for the additional costs of manually reading ADMs will ensure that other customers are not paying for those private choices.

1.8.2 How can I avoid this new charge?

It is important to emphasise that this charge will not be paid by everyone. It will only affect a relatively small number of customers who have chosen to have the remote communication function of their ADM disabled. If you leave the remote communication enabled, you will not pay this new charge.

1.8.3 How did the QCA set this charge?

The direction asked us to set a retail charge based on Ergon Energy Retail's averaged costs of manually reading a type 4A meter. While we consider this approach appropriate, Ergon Energy Retail (EER) informed us that this information is not readily available. We understand that the costs to manually read meters may vary from customer to customer depending on geographic location, meter accessibility, availability of meter reading staff and other factors.

We are of the view that manually reading a type 4A meter is an activity similar to a special meter read. As such, we are of the view that the AER-approved special meter read fee provides a reasonable benchmark for setting the type 4A manual meter read fee. However, we intend to consider alternative benchmarks based on available information from EER and/or stakeholder submissions.

1.9 Solar feed in tariff [to cover if we have time]

1.9.1 Why is the feed-in tariff different to those available in SEQ?

Customers in the deregulated south-east Queensland electricity market can access a wide range of solar feed-in tariffs.

The solar feed-in tariff rates offered by retailers in SEQ do not necessarily reflect the avoided cost of purchasing electricity from the NEM—which is the methodology we are required to use to determine the regional solar feed-in tariff.

Retailers in SEQ use a variety of pricing strategies to balance attracting and retaining customers and being profitable.

1.9.2 Why is the feed-in tariff less than the price I pay for electricity?

The actual value of electricity generated by solar units is considerably less than the retail price, because when retailers source energy from solar customers, they only avoid some of their normal business costs. Such as the cost of purchasing electricity from the NEM and the value of energy losses.

Retailers still incur normal business costs, including retail operating costs and network charges. A 'one-for-one' feed-in tariff would require the retailers to subsidise solar PV customers; and the cost of the subsidy would then need to be recovered through higher electricity prices

1.9.3 Why is the standing offer adjustment not included as an avoided cost?

The methodology we use to set the feed-in tariff looks at the costs retailers incur to purchase electricity in the NEM and out of those, what we consider are reasonable estimates of costs they would avoid by sourcing it from solar PV customers.

The SOA is not a cost normally incurred by retailers purchasing electricity from the NEM. It is intended to reflect the value of more favourable terms and conditions attached to standing offers, compared to market offers. We do not consider including the SOA in the feed-in tariff as an avoided cost would represent a reasonable estimate of costs that retailers would avoid by purchasing electricity from solar customers rather than the grid.

As part of determining the feed-in tariff, we must ensure that the feed-in tariff we decide does not impede the development of retail competition in regional Queensland. Its inclusion would set the feed-in tariff above what a reasonable estimate of avoided costs are and may inhibit or discourage other retailers from entering the regional Queensland market - as they are required to offer the feed-in tariff we set to their solar customers.

1.9.4 If the cost of energy increased last year, and that is linked to the feed-in tariff, why haven't I received a higher rate from last year?

We are directed to set the feed-in tariff by the Queensland government - this is generally done once a year and the tariff applies from 1 July each year. After it was last set, the cost of energy increased significantly. It is true that this increased cost of energy has not been reflected in an updated feed-in tariff for the current year. However, on the other hand, it is also important to note that the higher cost of energy over the last 9 months has also not been reflected in notified prices.

1.9.5 We just spent a lot of money installing solar panels, can you guarantee the feed-in tariff won't decrease / change in the future?

We are directed to set the feed-in tariff by the Queensland government - without the government's direction, we cannot set a feed-in tariff. We cannot guarantee we will given the task in any given year.

However, if we were, and we were directed to use the same avoided cost methodology as this year, the feed-in tariff we set next year would reflect updated forecasts for energy costs (which are the main component of the feed-in tariff). It is very difficult to predict what energy costs will be like next year.

So for those 2 reasons, we cannot offer any guarantees about what the feed-in tariff might be next year or any future years.

1.9.6 I used to get 44 cents from my retailer, and now I don't.

You need to get in contact with Ergon Distribution and discuss with them why you have lost access to the scheme. The Queensland government website also has details on maintaining or losing eligibility for the scheme, we can offer you that address after the session if you would like.

https://www.qld.gov.au/housing/buying-owning-home/energy-water-home/solar/feed-in-tariffs/solar-bonus-scheme-44c

1.9.7 I get the 44 cents feed-in tariff and my retailer said it would not offer me its feed-in tariff on top of that.

For regional customers, the feed-in tariff we set is not applicable for customers receiving the 44 cent feed-in tariff. That means, if you receive the 44 cent feed-in tariff, you will not also get the feed-in tariff we set on top.

For customers in the deregulated SEQ market - it is up to each individual retailer to decide whether they pay their own feed-in tariff on top of the 44 cent feed-in tariff.

1.9.8 Why isn't the feed-in tariff set using spot prices or higher during peak periods?

Spot prices change every 5 minutes and can go from negative $1000 during the middle of the day to over $15000 during peak periods. That is a lot of volatility and risk for retailers needing to buy electricity for their customers.

So, to manage that risk, retailers use 'hedging' strategies to lock in agreed prices with generators for electricity. Hedged wholesale energy costs represent a reasonable estimate of the direct financial costs that a retailer avoids when it on-sells exported electricity from its solar PV customers to other customers

So, that is why we use the 'hedged' wholesale energy cost estimates, and not spot prices, to set the solar feed-in tariff.

1.9.9 Ergon said they wouldn't allow me to connect my solar system to the grid.

Before Ergon Retail can offer you a feed-in tariff, Ergon Distribution must agree to connect your solar system to the grid and allow you to export electricity. Sometimes Ergon Distribution will assess that the network in your area is not capable of supporting more solar PV and won't allow new connections. This is an issue you need to discuss with Ergon Distribution.

INFORMATION SESSION RUNSHEET

1.1 N+R cost build-up methodology

(1) This year, the Minister asked us to use the network plus retail (or N+R) cost build-up methodology to set notified prices. This is the same approach we have used in previous years.

(2) Under this approach, the:

(a) N component (or network costs) are treated as a pass through - that is, , we pass through the network prices and tariff structures approved by the Australian energy regulator…

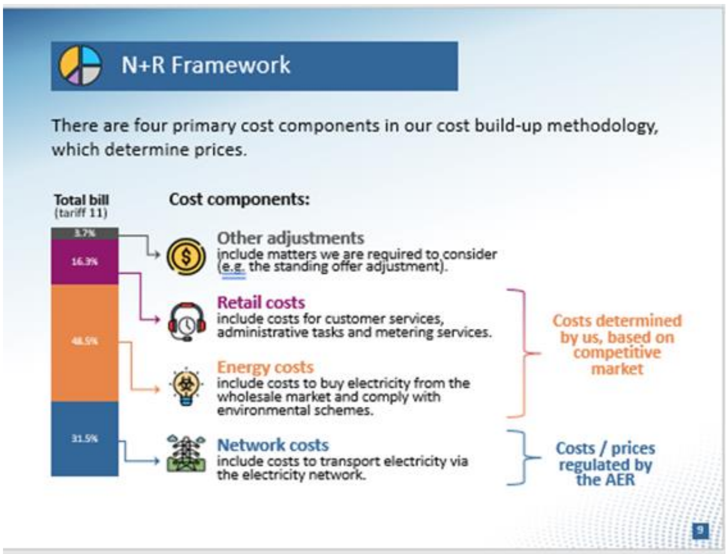
(b) R component (which consist of the retail and energy costs) is determined by us

(c) Other costs and adjustments which we also calculate.

(3) Under this approach the underlying network prices as the basis for setting the retail tariffs, then the other cost components are added on to build-up the total notified price.

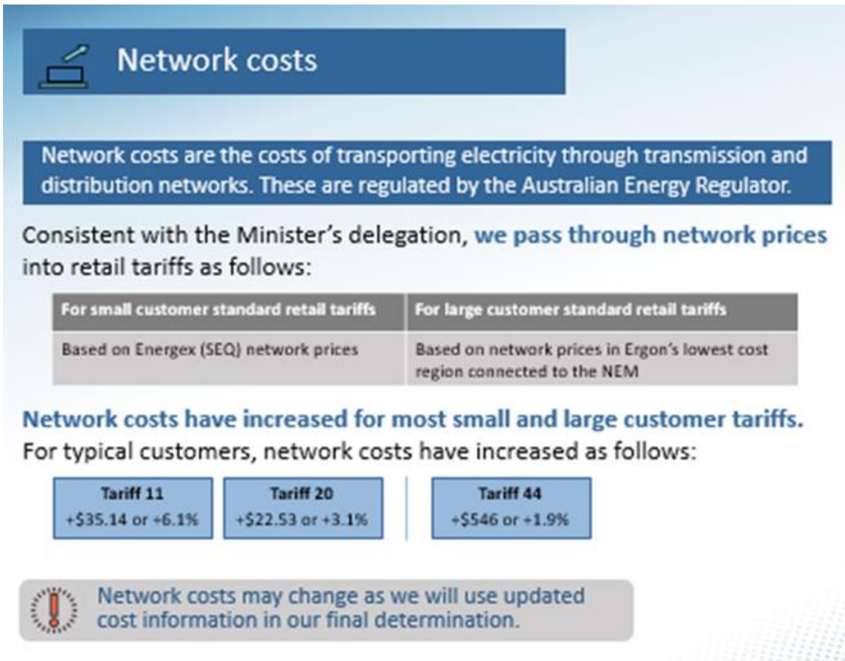
(4) The bar chart shows how the components contribute to a typical customer bill this year… as you can see energy costs are the largest component of the bill, followed by network costs, with retail and other costs making up the remainder.

(5) the approaches we have used to set these costs is largely consistent with the past determinations, so this is likely to be familiar to those of you familiar with our past determinations and approaches.



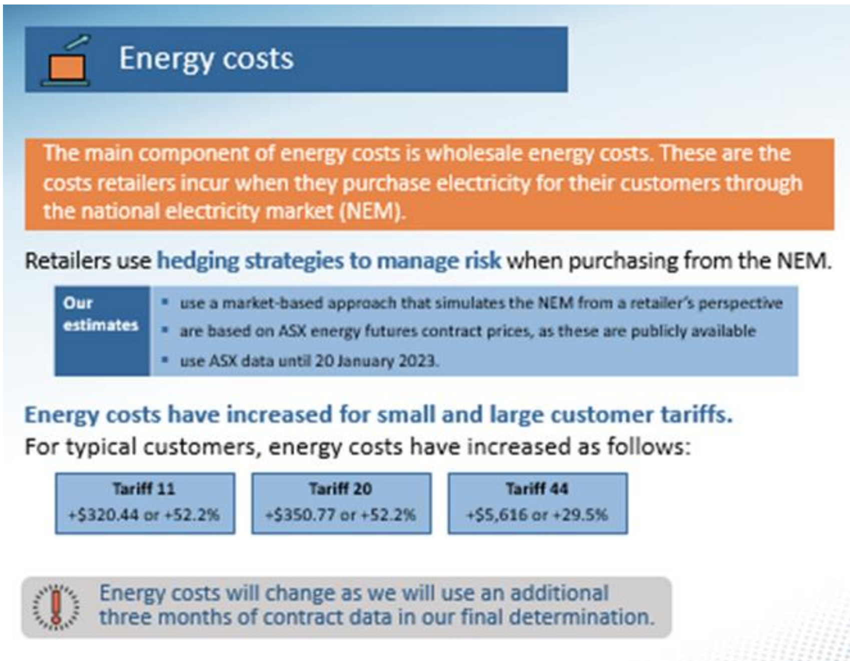
1.2 Network costs slide

- First component is network costs, which relate to the costs for transmission and distribution of energy – the 'poles and wires' so to speak.
- We have used the same approach this year to set network costs, where the N component is treated as a pass through … so we pass through network prices that are approved by the Australian Energy Regulator (or AER).
- Consistent with the UTP, we have used the Energex network prices for small customers; and for large customers the network prices for the lowest cost Ergon region connected to the NEM.
- As you can see, this year network costs are increasing for all customers - by around $22-$35 for small customers and … $550 for large customers. -
- As the AER has yet to approve network pricing for the next financial year, we have used draft network prices supplied to us by Energy Queensland. We intend to use finalised and AER approved network prices for our final determination, subject to availability of course.



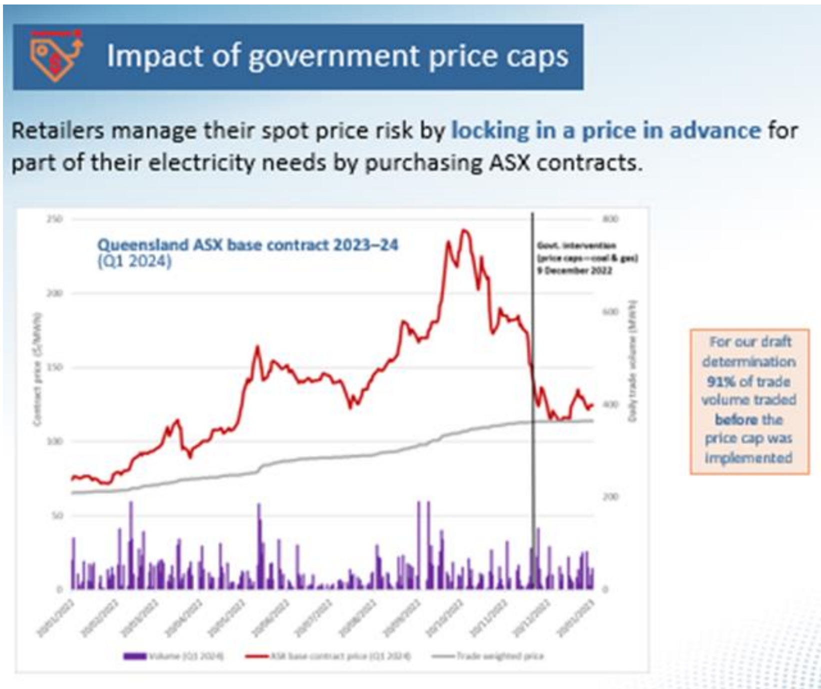
1.3 Energy costs slide

- Main driver of high costs
- the key component - wholesale energy costs -
- To estimate costs, we use a market hedging approach, which estimates the costs retailers face in the NEM.
- Estimating energy costs is quite complex, but generally it involves estimating the costs a prudent retailer would face from forward purchasing energy contracts in the NEM for the bulk of their requirements, as well as some spot market costs.
- information that is public information, including on spot prices and futures contracts traded in the ASX.
- We have taken into account government price caps - which I'll discuss next.
- Draft wholesale energy costs are expected to increase for both small and large customers:
  - The market conditions have been volatile due to
    - higher coal and gas prices. This has been caused by international factors, such as the war in Ukraine and energy sanctions. Domestic factors have also been at play, such as uncertainties around the availability and reliability of coal-fired power plants and their impacts on the supply-demand balance in Queensland.
    - Temporary price caps on coal and gas prices have now been put in place by government and we have seen recent falls in energy prices. But a substantial portion of costs have already been locked in by retailers through their hedging activities.
- For the draft determination, we used data up until January 2022 - to account for the most current developments while still publishing on time.
- For the final, we will use ASX data up until late April early May to estimate costs.



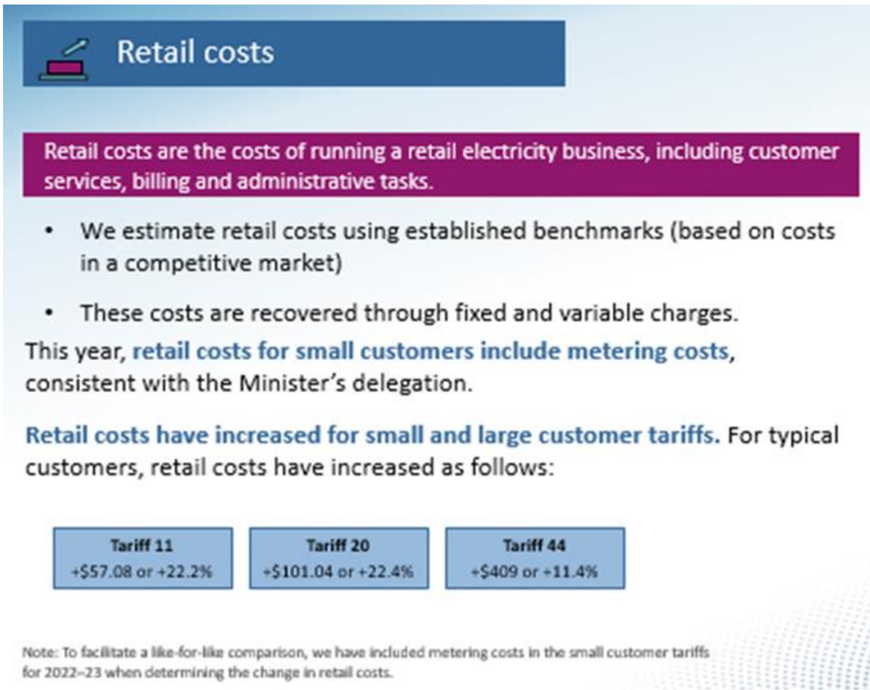
1.4 Impact of government price caps slide

- This chart shows the what has happened in the contract market since January last year
- Red line… shows the movement of the trade in Queensland ASX base contract prices over time
- Purple bars shows the volume of energy contracts traded
- Grey line near end - marks the date of when the government price caps were introduced– early Dec 2022–
- Chart goes out to 20 January - which is the cut-off date for contract data that we used in our draft determination.
- As you can see, majority of the volume was traded before our data cut-off.
- Important - grey line
- Price caps have been put in place on coal and gas prices. We have seen recent falls in energy costs but substantial portion of costs have already locked in by retailers through their hedging activities.
- Late last year, the Australian Government partnered with the states and territories on an Energy Price Relief Plan. Part of this plan was the introduction of temporary price caps on coal and gas prices.
- We will use updated data in our final determination so wholesale energy costs may change.



1.5 Retail costs slide

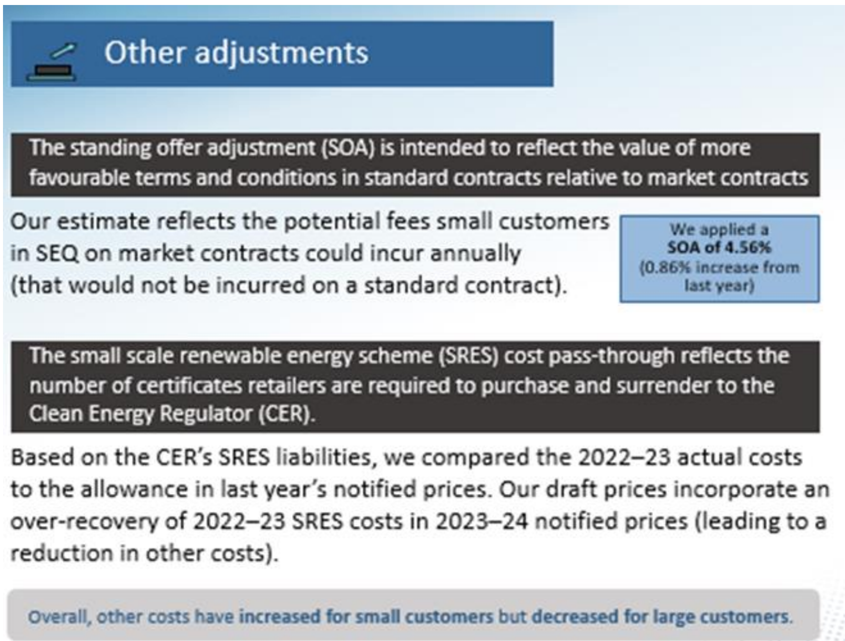
- Retail costs include the costs a retailer incurs to run its business and look after its customers.
- This year, we used the same approach to set retail costs as that used in the past - we used the established benchmark allowances, adjusted for CPI.
  - We established the benchmark allowances some time ago.
  - For small customers - Uses market offers in SEQ which is available publicly, then - by deducting the network and energy costs from the total retail tariffs, the retail costs can be derived (and benchmarked). We did a detailed review of these a few years ago and updated the small customer retail allowances to take account of updated market data
  - For large customers we used the existing benchmark established (in 2016-17).
- This year retail costs are increasing for customers.
- Metering
  - The main change this year is that retail costs for small customers now include metering costs, which the Minister asked us to include in retail costs this year.
  - These metering costs were previously paid by customers as a separate item on your bill, but now they are incorporated into retail costs, which form part of the tariff price.
  - The metering costs also include additional costs associated with digital meters



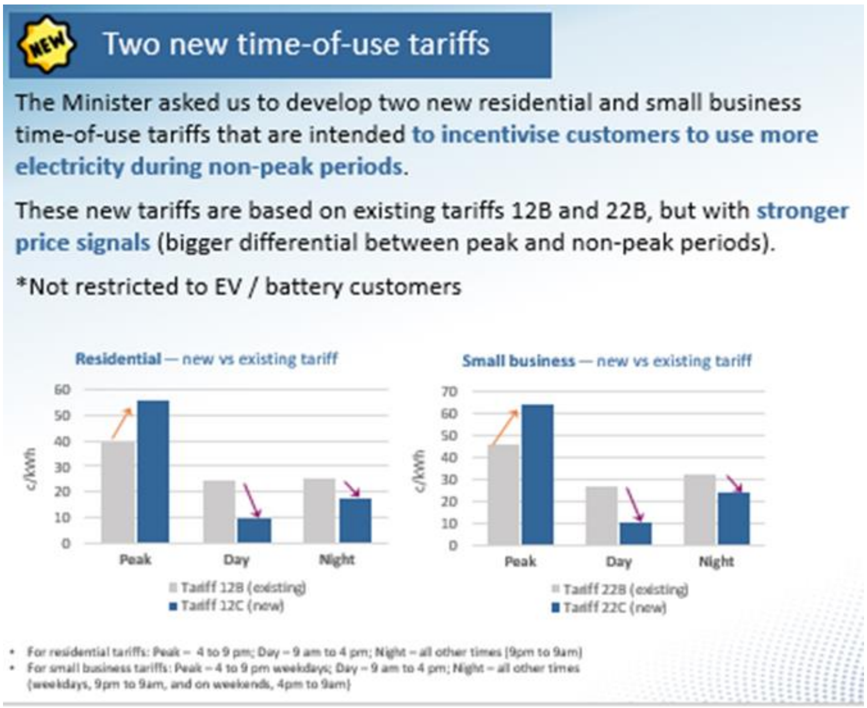
- Anything on excess margins (assumes that market is not effectively competitive). The number of retailers and market offers indicate the market is likely to be pretty competitive - and therefore retailers generally not include excessive margins (otherwise would be put out of business).
- For retail costs, took into account discounts in retail market offers (i.e. took them off).

1.6 Other adjustments slide

- These adjustments are matters that we are required to consider under the pricing framework.
- The first is the standing offer adjustment - which is the adjustment the Minister asks us to include in small customer notified prices to reflect the costs and benefits associated with standing offer contracts in SEQ (given the UTP)
- We have incorporated an adjustment of 4.56% (or $59) into small customer prices
- Similar to previous years, we used an avoided cost method to estimate the SOA - that is, we looked at the potential fees customers on market contracts could incur in SEQ, that would not be incurred on a standard contract.
- We use this as a proxy for the additional value the terms and conditions contained in standing offers provide to customers.
- You will also see the small-scale renewable energy scheme costs. I won't go into too much detail on this, other than to say these costs will be reduced this year to account for an over-recovery last year.
- This can occur because these costs are settled at the end of the year, whereas we must make our decision mid-year, so we make adjustments to account for differences between the costs we used in our decision and the actual costs set after our decision was made.



1.7 Two new time-of-use tariffs slide

- The Minister asked us to develop two new tariffs this year for small customers.
- These are time of use tariffs that have different charges based on whether you use electricity during the peak or non-peak periods.
- The new tariffs are based on existing time of use tariffs, but with stronger price signals and are meant to encourage customers to use more energy during the (when renewable energy generation is high and network utilisation is low).
- For these tariffs, we use the same network costs as those used in existing tariffs, but then set the energy costs to provide the stronger price signals.
- So if you can shift your consumption to during the day or in the overnight period, you could save money compared to a flat rate tariff, where usage charges are the same across the whole day.
- You can see this difference in rates on the charts - where the rates are higher in the peak periods and lower in the day and night (the non-peak periods).
- There was some discussion in subs around these tariffs - particularly around how it might provide incentives for customers with electric vehicles to be charged during the day.
- While that is true, these tariffs can be used for any consumption - you don't need to be an EV owner - any customer that can access the existing time-of-use tariffs can access these new ones.
- 

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1.8 Way forward slide

- Thank you for joining us today and participating in the information session. Hopefully this session has provided you with a better knowledge of the draft determination and prices, including explaining why prices and increasing this year and the main reasons for this.
- We are particularly keen to hear from stakeholder comments about the new tariffs.
- Submissions are due 14 April and we expect to have the final report published by the end of May. Submissions can be uploaded to our website using the submissions tab on the home page.
- If nothing further - thank you!

Energy costs

Energy costs for all customer groups ~~were~~ are estimated to **increase**, primarily driven by higher wholesale energy costs (Table 2).

Table 1 Energy costs, 2022–23 and 2023–24 (excl. GST)

Customer group	*Main retail tariff*	*2022–23 Final*	*2023–24 Draft*	*Change from 2022–23 Final*	
		$/MWh		***$/MWh***	***%***
Energex (Small Customers)	Tariffs 11, 20	$125.01	$190.21	$65.20	52.2%
Energex CLP 9000	Tariff 31	$107.77	$126.77	$19.00	17.6%
Energex CLP 9100	Tariff 33	$113.09	$133.02	$19.93	17.6%
Energex (Large Business)	Tariffs 44, 45, 46	$113.28	$146.65	$33.37	29.5%

Wholesale energy costs

The level of wholesale energy costs is determined by the prevailing market conditions in the NEM and relevant financial markets. Our approach in estimating wholesale energy costs is designed to closely reflect these market dynamics, which are best approximated by publicly available prices and trade volumes of ASX contracts.

In practice, retailers adopt a range of hedging strategies to manage spot price volatility within the NEM[1], including through the purchase of ASX contracts. Generally, the purchase of ASX contracts enables retailers to lock in a price, or a maximum price (in the case of cap contracts), at which a given volume of electricity will be transacted at a future date. Therefore, ASX contract prices incorporate market participants' expectations of future spot prices.

1.1.1 Key drivers

Compared last year's estimates, **wholesale energy costs** are estimated to **increase** for all customer groups (Table 3). These changes in costs reflect a significant **increase** in the **trade-weighted prices** for **ASX** base and cap **contracts** (Table 4). The increase in ASX contract prices is driven by market participants expecting higher future spot prices and greater price volatility, which is likely due to:

- higher gas and coal prices. Thermal generators have been facing higher fuel costs due to the war in Ukraine and energy sanctions imposed on Russia (a major global oil, gas and thermal coal producer). These developments have added further uncertainty to energy markets already impacted by global supply constraints[2] (due to the covid-19 pandemic), which led to high and volatile gas and thermal coal prices (Figures 1 and 2)
- uncertainties associated with the availability and reliability of coal-fired power plants and their impacts on the supply–demand balance in the Queensland NEM region. For example, Kogan Creek began a scheduled outage in September 2022 for a major overhaul and its return to service was delayed for more than a month due to unforeseen additional repairs required.[3] Further, Callide C (unit 3) suffered from a forced outage since October 2022. Callide C's operator (CS Energy) initially advised that the unit

[1] The NEM is a volatile market where spot prices are settled every 5 minutes and currently can range from –$1,000 to $15,500 per megawatt hour (MWh).
[2] See Bloomberg, Commodities soar as war builds anxiety over supply shortages, accessed in January 2023.
[3] See CS Energy, Kogan Creek power station overhaul extended, accessed in January 2023.

was expected to return to service in February 2023 but this timeframe was later revised to May 2023.[4] CS Energy also delayed the return of service of Callide C (unit 4) from April to May 2023.[5] These outages have reduced the average available capacity by around 864MW in Q4 2022.[6]

Our wholesale energy cost methodology also incorporates the potential impacts of temporary price caps for gas and coal, which were implemented by Commonwealth and Queensland Governments in December 2022 (see section 1.1.2 for more information).

Table 2 Wholesale energy costs, 2022–23 and 2023–24 (excl. GST)

Customer group	***Main retail tariff***	***2022–23 Final***	***2023–24 Draft***	***Change from 2022–23 Final***	
		$/MWh		***$/MWh***	***%***
Energex (Small Customers)	Tariffs 11, 20	$94.93	$157.99	$63.06	66.4%
Energex CLP 9000	Tariff 31	$78.80	$98.65	$19.85	25.2%
Energex CLP 9100	Tariff 33	$83.78	$104.49	$20.71	24.7%
Ergon (Large Business)	Tariffs 44, 45, 46	$84.61	$118.74	$34.13	40.3%

Table 3 Queensland trade-weighted ASX contract prices

Contract type	***Quarter***	***2022–23 Final***	***2023–24 Draft***	***Change***	
		$/MWh		***$/MWh***	***%***
ASX base contract	Q3	$58.31	$102.26	$43.95	75.4%
	Q4	$59.76	$90.28	$30.52	51.1%
	Q1	$78.22	$114.08	$35.86	45.8%
	Q2	$57.43	$84.11	$26.68	46.5%
ASX cap contract	Q3	$13.32	$18.59	$5.27	39.6%
	Q4	$15.04	$21.67	$6.63	44.1%
	Q1	$29.53	$36.03	$6.50	22.0%
	Q2	$8.31	$14.72	$6.41	77.1%

Source: ASX Energy.

Note: To calculate the trade-weighted ASX contract prices for 2023–24 draft determination, we have used contract prices and volume of contracts and exercised options traded until 20 January 2023 inclusive. Such an approach takes into account the most current information (including developments over the potentially volatile summer period), while still meeting our draft determination timeframe.

[4] See CS Energy, Updated return to service date for Callide C units, accessed in January 2023.

[5] Callide C (unit 4) has been unavailable since May 2021 following a major explosion. See CS Energy, Updated return to service date for Callide C units, accessed in January 2023.

[6] AEMO, Quarterly Energy Dynamics Q4 2022, January 2023.

Figure 1 Newcastle thermal coal export prices

Source: Bloomberg Intercontinental Exchange (ICE).

Figure 2 Asian liquefied natural gas (LNG) prices

Source: Bloomberg Intercontinental Exchange (ICE).

1.1.2 Government intervention

In December 2022, the Australian Government partnered with the states and territories to introduce an Energy Relief Plan with measures to address high energy costs. Key aspects of this plan include temporary price caps for gas and coal, which are key input costs for thermal generators. Under this plan, wholesale gas and coal prices for electricity generation would effectively be capped at $12/GJ and $125/tonne respectively (for at least 12 months).

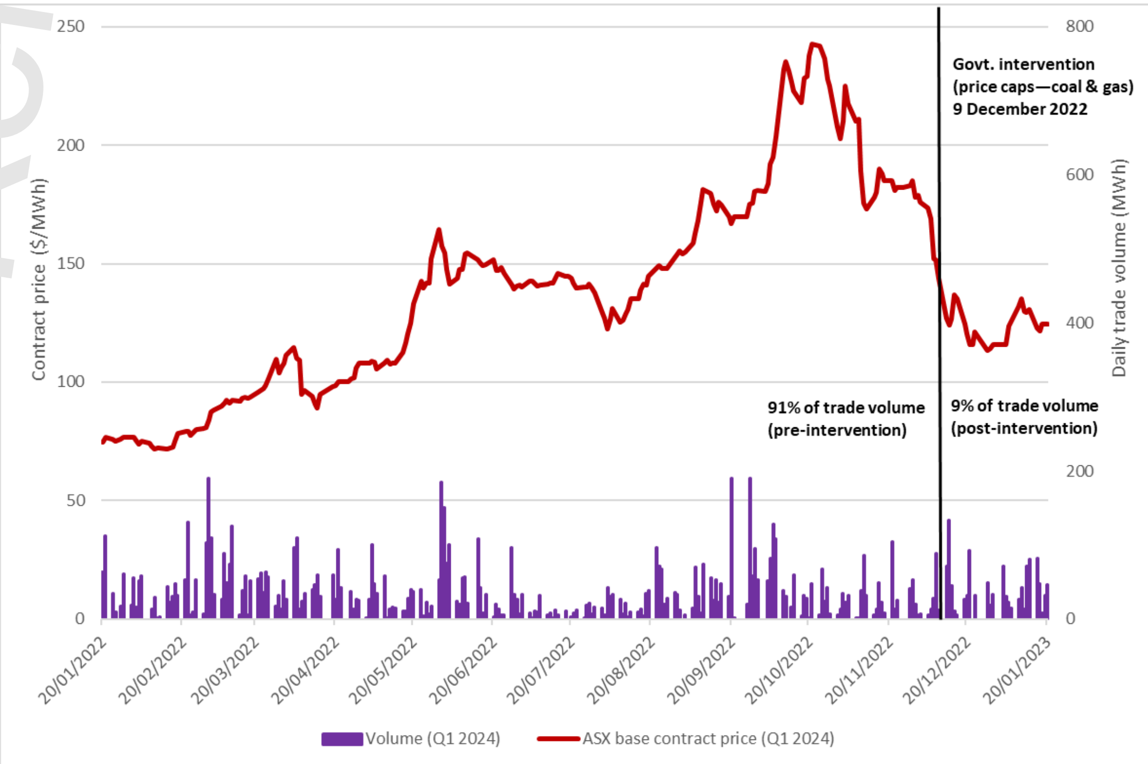
Our wholesale energy cost methodology captures the potential impacts of these caps through our spot price analysis and the incorporation of ASX contract prices (until 20 January 2023 inclusive). Importantly, the ASX contract prices reflect, to date, the market participants' views of the potential impacts of these temporary price caps on the NEM. The potential effects of these caps are best illustrated using the price and trade movement of ASX base contracts for the summer quarter for 2023–24, i.e. Q1 2024 (Figure 3).

As shown in Figure 3, prior to the war in Ukraine intensifying in late February 2022, ASX base contract prices for Queensland (Q1 2024) averaged around $67/MWh. From then on, these contract prices have increased substantially, reaching a record high of approximately $243/MWh in late October 2022 before declining to around $150/MWh prior to the government intervention in early December 2022. Since the commencement of the temporary price caps, these contract prices have decreased further, fluctuating between $113/MWh and $137/MWh.

However it is important to note that, in practice, retailers manage their spot price risk by locking-in a price (or a maximum price[7]) in advance for part of their electricity requirements via trading in ASX contracts. In other words, retailers have already locked-in a portion of their costs for 2023–24 prior to the commencement of the temporary price caps. This market dynamic can be demonstrated using the movement in trade volume for the ASX base contracts (Q1 2024), where approximately 91% of the contracts traded were locked-in before commencement of the price caps. This means that only 9% of ASX contracts traded were influenced by the price caps (Figure 3).

It is expected that the temporary price caps would put downward pressure on the trade-weighted ASX contract prices (and in turn wholesale energy costs) as more ASX contracts are traded while the price caps are in force. For our final determination, we will use ASX data until late April/early May 2023 to estimate contract prices.

Figure 3 Queensland ASX base contract 2023–24 (Q1 2024)



Source: ASX Energy and QCA analysis.

[7] Retailers can lock in the maximum price for future electricity purchases by trading in ASX cap contracts.

1.1.3 Methodological refinement—wholesale energy costs

To better reflect the latest market developments, we have also refined our wholesale energy cost methodology by:

- incorporating demand profiles of smart meters to better approximate the consumption pattern of electricity. Since the introduction of the AEMC's Power of Choice reforms[8] in 2017, installations of new rooftop solar PV would involve an upgrade of meters (from accumulation to smart meters). This means that the demand profiles based on only accumulation meters (i.e. the net system load profiles (NSLPs)) would likely misrepresent the consumption pattern of electricity. This is because the reduction in day-time demand due new rooftop PV output would be captured by smart meters instead of accumulation meters (and by extension the NSLPs).

  To address this issue, we have combined the relevant smart meter profiles with the NSLPs when estimating wholesale energy costs. This is consistent with what retailers do, in practice, when developing their hedging strategies. Based on informal discussions, retailers in south east Queensland advised that they would not distinguish between customers with different meter types but would combine the profiles for smart and accumulation meters (for a specific customer group) when undertaking hedging activities.

- improving our estimation of the costs that retailers faced when trading in ASX options to manage spot price volatility. Our initial approach to estimating ASX contract prices includes options traded by using a simplified approach, where options were approximated using the volume of options traded and ASX daily settlement prices for base contracts.

  However, recent market volatility has prompted us to consider refining this approach. To reflect the costs of trading in options more accurately, we have incorporated the:

  – strike prices of call options[9] exercised

  – premiums of call options exercised and expired

  – trade volume of call options exercised and expired.

Other energy costs

Compared to the estimates from last year, we estimated that:

- **LRET costs** would **increase**—driven by an increase in the forward prices of large-scale generation certificates due to higher voluntary demand for these certificates
- **SRES costs** would **decline**—driven by a decline in the estimated number of small-scale technology certificates retailers are required to purchase
- **NEM fees** would **increase**—reflecting an increase in costs related to operating the NEM, including the costs associated with the five-minute settlement reform and the integration of distributed energy resources

[8] As part of this reform, the AEMC implemented rule changes to facilitate a market-led deployment of smart meters across the NEM. Among other things, these rule changes required that, from 1 December 2017, all new and replacement meters for small customers to be smart meters.

[9] In this context, call options are a type of financial derivative that gives the holder the right, but not the obligation, to purchase (exercise) ASX base contracts at a predetermined price (known as the "strike price") and volume. In exchange for this right to exercise, the holder (buyer) will pay a premium to the seller of the call option (regardless of whether the holder chooses to exercise the option).

- **ancillary services charges** would **decrease**—due to lower costs for frequency control ancillary services (FCAS) in Queensland. The completion of upgrades for the Queensland to New South Wales interconnector (QNI) in June 2022 has reduced the need for local supply of FCAS in Queensland.
- **prudential costs** for **small customers** would **increase**—driven by elevated contract prices, greater expected price volatility in the NEM and the shape of the relevant demand profile becoming 'peakier' (due to a due to a substantial uptake of rooftop solar PV, which decreased daytime demand but had limited effect on the evening peak demand)
- **prudential costs** for **large customers** would **decrease**—primarily due to the shape of the relevant demand profile becoming 'flatter' over time (with more electricity consumed during the off-peak daytime period, instead of during the evening peak period)
- **Reliability and Emergency Reserve Trader (RERT) costs** would **decline**—driven by fewer activations of the RERT to assist with power system management (excluding RERT activations during events in June 2022, see June 2022 events)

We have also estimated the costs associated with **market events in June 2022** using the latest data from the AEMC and AEMO. These include the RERT costs and compensation costs published by the AEMC and AEMO to date. The compensation costs are in relation to the trigger of the administered price cap and suspension of the wholesale market by AEMO (from 15 to 24 June 2022).

Table 4 Other energy costs, 2022–23 and 2023–24 (excl. GST)

Cost component	*2022~~1~~–23~~2~~ Final*	*2023~~2~~–24~~3~~ Draft*	*Change from 2022~~1~~–23~~2~~ Final*	
	$/MWh		*$/MWh*	*%*
Large-scale Renewable Energy Target (LRET)	$5.00	$7.19	$2.19	43.8%
Small-scale Renewable Energy Scheme (SRES)	$10.90	$6.86	–$4.04	–37.1%
NEM Fees	$1.13	$1.15	$0.02	1.8%
Ancillary Services	$1.42	$0.60	–$0.82	–57.7%
Prudential Capital (Small customers)	$2.55	$3.24	$0.69	27.1%
Prudential Capital (Large customers)	$2.10	$2.00	–$0.10	–4.8%
Reliability and Emergency Reserve Trader (RERT)	$1.01	$0.01	–$1.00	–99.0%
June 2022 market events	$0.00	$0.89	$0.89	—

4 page document - pages 1 - deleted - Section 73 - irrelevant information

Member comments on notified prices [redacted]	
[redacted] Section 73 - Irrelevant Information	[redacted]
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[redacted]	[redacted]
[redacted] Section 73 - Irrelevant Information	[redacted]
[redacted] *Article on Callide C closure*—Is this likely to impact the regional pricing determination If so, can it be reflected in the draft determination. If it cant, and I am relaxed if it cant, we should at least provide commentary that we are aware of this and its effects cant be reflected in the draft but will be in the final	[redacted]
[redacted] updated return to service dates of callide C.	[redacted]
[redacted]	
[redacted]	[redacted]

Queensland Competition Authority

Information pack

Regulated retail electricity prices 2023–24 Regional Queensland

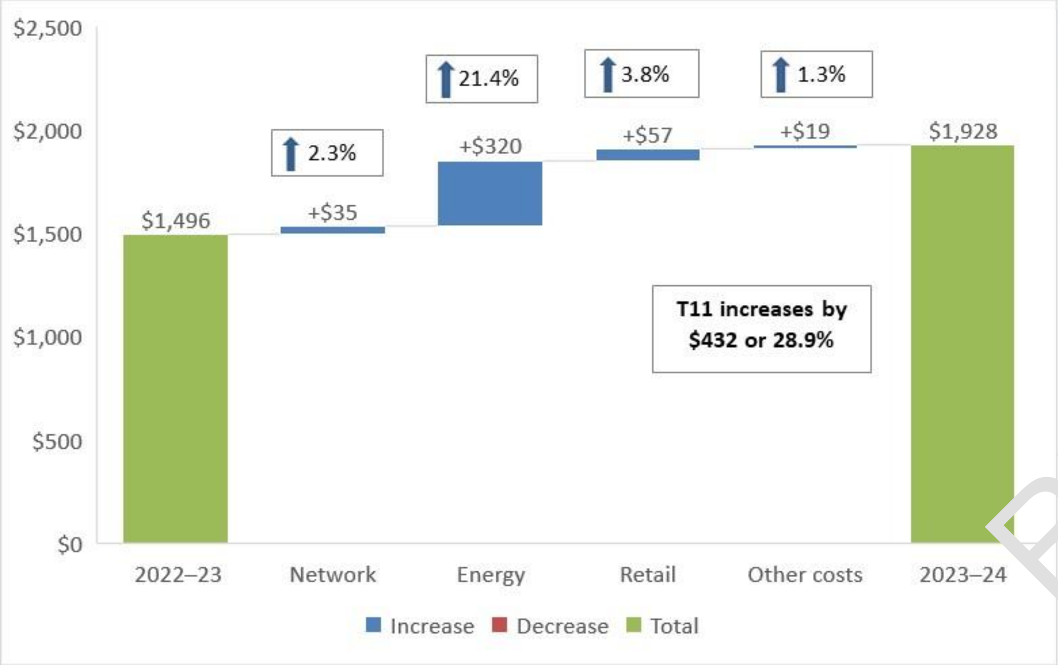
Draft determination

8 March 2023

Expected customer bill impacts

Bills are expected to be higher for all customers in 2023–24 largely due to an increase in estimated energy costs and, to a lesser extent, increases in other cost components:

- **Tariff 11—Residential:** expected to increase by 28.9%



- **Tariff 20—Small business:** expected to increase by 26.1%
- **Tariff 44—Large business:** expected to increase by 12.2%. Prices do not increase as much for large customers due to the smaller increases in wholesale energy costs (as a result of flatter consumption profiles compared to small customers, which is less expensive to hedge).

Drivers of increased prices

Energy costs are the main driver for price rises this year, with a substantial increase in wholesale energy costs, primarily due to:

- higher coal and gas prices, impacted by the war in Ukraine
- uncertainties associated with the availability and reliability of coal-fired power plants.

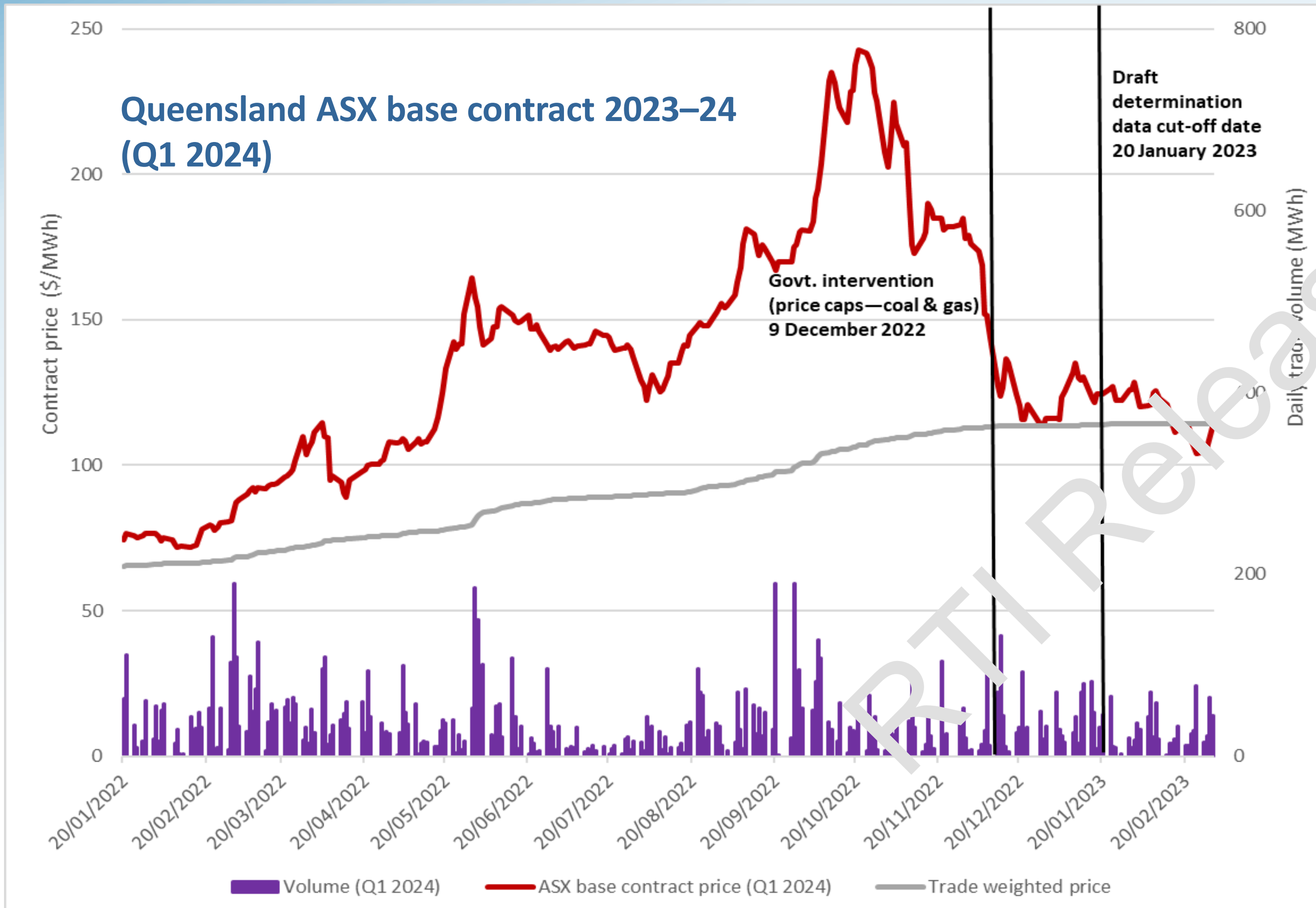
Recent price caps (**on coal and gas**) have been incorporated, but the majority of wholesale costs were already locked in by retailers before the introduction of the caps (see next slide).

Retail costs are higher because they now include the costs of metering services (for small customers).

Network costs are higher based on draft network prices from Energy Queensland.

Other costs are increasing for small customers as the standing offer adjustment is calculated as a percentage of the total costs (as identified above).

Impact of price caps



Retailers manage their spot price risk by **locking in a price in advance** for part of their electricity needs by purchasing ASX contracts.

Changes between draft/final

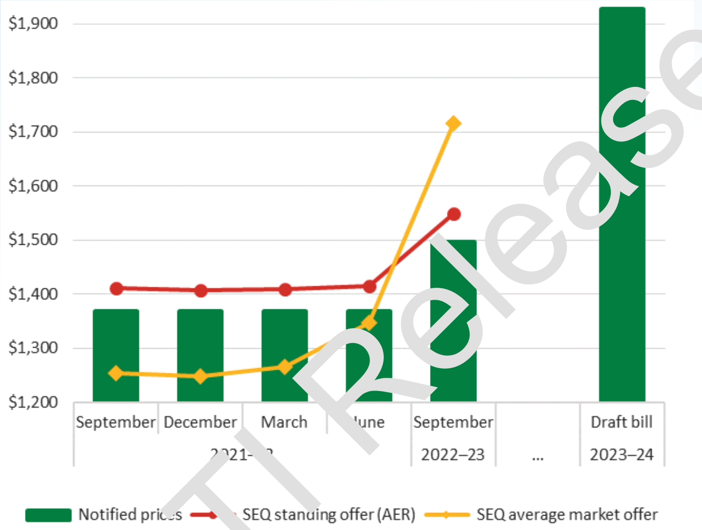
Prices may change between our draft and final determinations due to:

- **updated network prices**—for the final determination, we will use updated network prices.
- **updated ASX market data for the estimation of wholesale energy costs**—the draft determination includes ASX data up until 20 January 2023 but we intend to use ASX data until late April/early May 2023 for the final determination.
- **the AER's 2023–24 default market offer for south-east Queensland**—for our final determination, we will do a comparison with the AER's DMO reference bill to assess whether the standing offer adjustment needs to be adjusted (which would have a flow-on effect on final notified prices).
- **changes in other costs**—other costs will be updated for our final determination if more up-to-date information becomes available, including metering costs and costs associated with the June 2022 market events.

Price increases over time

Real and nominal (CPI) annual notified price bills (T11, including metering costs)

Bill comparisons—SEQ and notified prices (T11)



- Average SEQ market offers increased by 27% (Jun to Sept Qtr 2022), exceeding the SEQ standing offer (AER)
- Recently, Energy Australia announced out of cycle rate increase from 1 March 2023

Notes: Bills based on a median consumption of 4,468 kWh per year. Terms and conditions may vary for offers in SEQ.

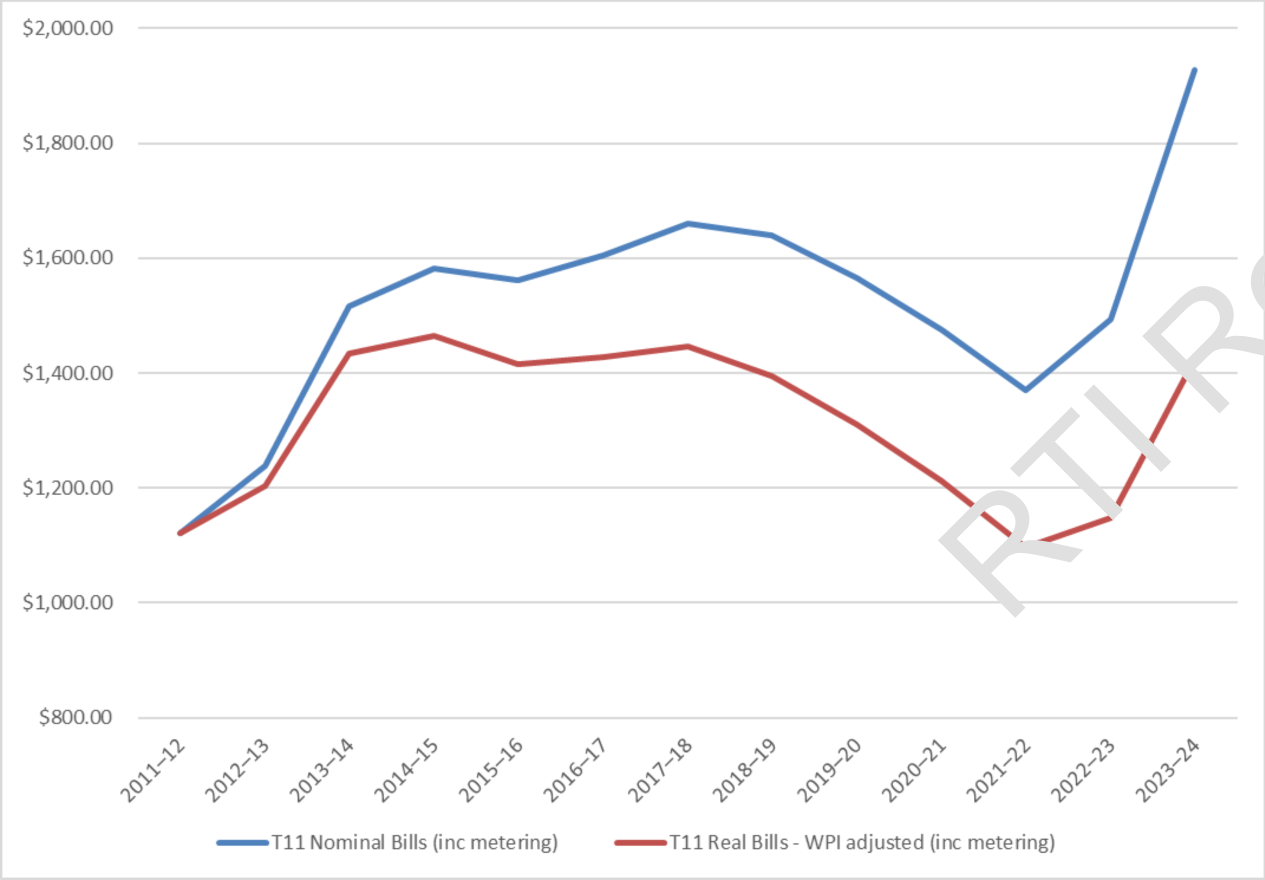
Short to medium term outlook

Beyond the 2023–24 notified prices, the outlook remains uncertain due to a number of factors:

- **Government intervention**—temporary price caps on gas and coal in place; further intervention possible (e.g. pending mandatory code of conduct for domestic gas producers). Nature and impact of such interventions unclear.
- **Reforms**—broad range of reforms taking place right across the NEM, with a range of consequences and potential implications for electricity prices.
- **World events**—the continuation of the war in Ukraine and other world events that impact input costs (such as coal and gas prices) will contribute to uncertainty in energy markets.
- **Network price review**—AER-approved network prices are used to determine network costs for notified prices. The outcomes of the AER's review of the network prices for Energex and Ergon Energy network businesses for the 2025–30 period are not expected until April 2025.

Price increases over time (WPI)

Real and nominal annual notified price bills (T11, including metering costs)



Notes: ABS used for WPI data until June 2022. QCA staff estimated WPI for observations after June 2022, based on available RBA forecasts.