13 October 2023

Att: Drew Butterworth
Australian Energy Market Commission
Level 15, 60 Castlereagh Street
Sydney
NSW 2000

By email: submissions@aemc.gov.au

Dear Mr Butterworth,

Submission on Opportunity Cost Methodology Consultation Paper

Snowy Hydro Limited welcomes the opportunity to respond to the Australian Energy Market Commission's Draft Opportunity Cost Methodologies Consultation Paper dated 14 September 2023 (**Draft Paper**).

Snowy Hydro commissioned Baringa Partners LLP to prepare an independent assessment of the AEMC's proposed methodology for assessing Snowy Hydro's claim for opportunity costs (**Baringa Report,** attached as Annexure 1). The Baringa Report sets out in detail the reasons why the opportunity cost methodology proposed by Snowy Hydro should be adopted and forms the basis of our submission. Snowy Hydro provides the following additional comments below.

Snowy Hydro's methodology is a market based valuation

The AEMC, in the Draft Paper, rejected Snowy Hydro's proposed methodology because, it claims, it adopted a "cost-based" approach and was therefore not consistent with the AEMC's Compensation Guidelines (**Guidelines**), which prefers a market based valuation.

The Guidelines state that the preferred method for valuing opportunity cost is "*a market based valuation of an alternative that over the relevant period of time would justify an opportunity cost. This valuation approach would be based on a range of information, including the available capacity and resources of the claimant's plant over this period of time and its cost structure….*"

For the reasons set out below, Snowy Hydro's proposed methodology, which is based on the cost of operating open-cycle gas turbine (**OCGT**) assets to make good the fuel depleted during the Administered Price Period (**APP**), is, in fact, a market based approach and should be adopted by the AEMC.

Valuing Hydro Generation

Referencing the shadow cost of operating OCGT assets is an accepted approach to valuing hydro generation. It reflects the fact that OCGT assets are, after hydro, typically the next most expensive generator in the bid stack and usually the only form of incremental generation able to replace the role of hydro as the marginal generator. This means that for hydro generators dispatched during an APP, the next best opportunity, that is, the opportunity cost, of that generation will be the shadow cost of operating OCGT assets at a later point in time in the market, after the APP has ended. For Snowy Hydro, the relevant period is the Snowy "Water Year", which is the period between 1 May and 30 April each year (see *Snowy Water Licence*, clause 1.1(105)). Given that the events in question occurred during June 2022, for the purposes of this claim the period for determining opportunity costs is the Snowy Water Year ending 30 April 2023. The cost of the shadow generation referenced in Snowy Hydro's methodology occurred in June and July 2022, within this period.

That being the case, the question then becomes how to value that shadow cost that Snowy Hydro could have achieved in the NEM. Snowy Hydro's claim is based on its own replacement (shadow) cost of operating its OCGT assets. This does not render Snowy Hydro's methodology a "cost based" approach. Rather, it is a market based approach because it references the cost of dispatched generation (ie. OCGT assets) which replaced the hydro generation during the APP and which determines the value of that hydro generation. It therefore represents a counterfactual (as required by the Compensation Guidelines), because it approximates the value (the avoided cost) of the hydro generation which would have been deployed if the APP did not occur.[1]

If Snowy Hydro had not generated during the APP, it would have had the opportunity to deploy that hydro generation during the period when it needed to procure replacement OCGT generation. To the extent that the AEMC's methodology values Snowy Hydro's hydro generation at a lower amount than the cost of that replacement generation, it is effectively denying that Snowy Hydro would have been able to deploy hydro generation during the period when it operated its OCGT assets. It would amount to the AEMC explicitly ignoring a better opportunity for Snowy Hydro to have used its hydro resource, contradicting the fundamental premise of the concept of opportunity cost. It would also mean that a fuel-constrained generator would not be indifferent to generating during the APP; it would create an incentive to withhold generation during the APP for more profitable use at a later time. This is inconsistent with the purpose of the APP compensation framework.[2]

[1] An alternative approach to developing the counterfactual would be for AEMO to re-run NEMDE (for each 5 minute interval for until the end of Snowy Hydro's Water Year, ie. 30 April 2023), assuming Snowy had not generated at its OCGT and Diesel assets and then selected the highest priced periods in which the 66GWh of hydro generation dispatched during the APP could have been allocated. This is a complex approach as the AEMC would need to consider other participants' bidding behaviour. A much simpler but neverthless robust approach is to consider the observed cost of running replacement OCGT assets, since those costs represent a proxy for shadow bidding.

[2] NER, clause 3.14.6(c)

Similarly, as mentioned, the fact that the cost of the shadow generation was sourced from Snowy Hydro's own portfolio of assets, rather than procured 'on-market' or theoretically assessed, does not in any way suggest that Snowy Hydro's methodology is not a market-based approach. In fact, that Snowy Hydro is able to verify those costs through fuel receipts should increase confidence in Snowy Hydro's methodology.

The Draft Report, on the other hand, proceeds on the basis that a market based valuation of opportunity costs can be determined solely by observing outcomes in the spot market (ie. the VWAP) in the period prior to the APP. This is unlikely to produce an accurate assessment of opportunity cost:

1) It ignores the fact that valuing opportunity costs of hydro assets should be based on the shadow cost of operating OCGT assets. Observing the VWAP of hydro assets in the two weeks prior to the APP does not reflect the "revealed preference" of Snowy Hydro, but rather simply the market outcomes over that period of time. Opportunity cost is fundamentally a forward looking concept and, consistent with the Guidelines, the AEMC should prefer a forward looking approach over one that relies on past periods. The APP influences the opportunity cost of the generation that took place during that period, and inferring its value based on spot market outcomes before the APP occurred cannot take into account the effect of the APP itself (in particular, the additional scarcity it created) and is therefore unlikely to be accurate.

2) A pure VWAP approach is not, in any case, an accurate market based approach, because it assumes away the existence of any contract position (that is, commitments made ahead of time to wholesale and/or retail customers) that may influence the bidding and dispatch into the spot market. Such contract positions, or customer commitments, typically incentivise generators to generate at VWAP below their short run marginal cost (**SMRC**) in order to manage contract exposure. In the case of Snowy Hydro's claim, this means that the *cost* of shadow generation (OCGT), not only VWAP, must be considered as the truest reflection of Snowy Hydro's market based assessment of the opportunity cost of its hydro generation.

   For further evidence of this, there are times when Snowy Hydro operates its OCGT at fuel costs materially higher than its bid price and the spot price it receives. This is because the combined marginal revenue of the spot and contract position revenue is perceived by Snowy Hydro to be equal to, or higher than, the fuel cost. Hence, the AEMC cannot infer Snowy Hydro's market valuation of its generation based purely on the spot price it generated at. Just as it is logical to assume that operating OCGT at spot prices lower than its fuel cost must have a market value of at least the OCGT fuel cost, it can be assumed that operating hydro plant with a shadow price equal to the SRMC of OCGT, at a spot price lower than the SRMC of OCGT, must have an actual market value of at least the OCGT SRMC.

Snowy Hydro is Not Seeking Compensation for Losses Arising with Respect to its Contract Portfolio

For the avoidance of doubt, Snowy Hydro is not seeking compensation for losses arising with respect to its contract portfolio. Rather, we reference the existence of Snowy Hydro's contract portfolio in order to address potential concerns that the using the cost of operating Snowy Hydro's OCGT assets (rather than its VWAP) as the basis for determining opportunity cost is not consistent with a market based assessment, and that this would therefore render Snowy Hydro's proposed methodology a cost based approach. If that were the case, following future APP events, Snowy Hydro and other fuel-constrained generators would be strongly incentivised to replace forgone hydro generation with third-party sourced energy (i.e. "buy off the spot market"), which would likely be significantly more expensive than sourcing it from within internal portfolios. This is because those third parties would not have the incentive to supply energy below the SRMC of their assets (as they are not managing a contract position to meet pre-existing customer commitments). It may also be the case that there are no other generators with similar OCGT SRMC that could replace our OCGT generation if it were removed,and this could lead to spot prices to rise as high as the Market Price Cap (**MPC**). In that sense, Snowy has been very conservative in valuing its opportunity cost at the SRMC of its OCGT generation and not the actual market value of that generation (in preventing spot prices as high as the MPC).

Importance of the Opportunity Cost Methodology

The opportunity cost methodology ultimately adopted by the AEMC is important not only to accurately assess compensation for the events in question, but to ensure the efficient operation of the market during future APP events.

The purpose of the APP Compensation framework, is, relevantly, to "maintain the incentive" for scheduled generators to supply energy during price limit events.[3] Snowy Hydro and other market participants acted responsibly during the crisis, generating below cost in order to keep the system secure. They were encouraged to do so by market bodies, including the AEMC, on the basis that they would be able to claim opportunity costs for any losses during the APP.[4]

Snowy Hydro has provided incontrovertible evidence that it generated using gas and diesel assets in circumstances where it could otherwise have generated using hydro generation that occurred during the APP. It has provided evidence of the cost of that generation. A compensation methodology which does not recognise these costs as opportunity costs would be to ignore the real world practice of generators. It would leave Snowy Hydro out of

[3] NER, clause 3.14.6(c)
[4] https://www.aemc.gov.au/news-centre/media-releases/apc-compensation-claims-update

pocket and create an incentive for all generators to withhold generation during future APP events - the very outcome the compensation framework seeks to avoid. Needless to say, this would have serious, negative consequences for the reliability of the NEM.

Snowy Hydro appreciates the opportunity to comment on the Opportunity Cost Methodology Consultation Paper

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Calculating opportunity cost during the administrative pricing period

CLIENT: Snowy Hydro Limited

DATE: 13 October 2023

Final Report

baringa.com

Version history

Version	Date	Description	Prepared by	Approved by
1	9.10.2023	Draft report	Tom Clark, Jacqui Fenwick, Stuart Gray, Nick Porter	Alan Rai
2	13.10.2023	Final Report	Tom Clark, Jacqui Fenwick, Stuart Gray, Nick Porter	Alan Rai

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1 Context of this engagement

On 12 and 13 June 2022, administered price caps (APCs) were applied at $300 per megawatt hour (MWh) in Queensland, New South Wales, Victoria and South Australia, within the National Electricity Market (NEM). This was triggered by regional reference prices reaching the cumulative price threshold (CPT). An administered price period (APP) was in place until 15 June 2022, at which point the Australian Energy Market Operator (AEMO) determined it was necessary to suspend the NEM. The market remained suspended between 15-23 June 2022.

During an APP, if generators continue to dispatch into the market and suffer a financial loss as a result of the APC, they may seek compensation under c3.14.6 of the National Electricity Rules (NER). The NER prescribes that compensation can be based on direct costs and opportunity costs (c3.14.6(d)) and is calculated in accordance with the guidelines developed by the Australian Energy Market Commission (AEMC) (c3.15.6(3)). In the case of 12-15 June 2022, the relevant document is version 4 of the *Compensation Guidelines*[1] (Guidelines) published on 21 October 2021.

Snowy Hydro Limited (SHL) notified the AEMC of its intention to make a compensation claim for direct costs and opportunity costs during the APP, in accordance with clause 3.14.6(h), on 21 June 2022. Its opportunity costs claim (the subject of this report) is regarding the Tumut 3, Upper Tumut and Murray power stations (collectively, affected generation units). As required under c3.14.6(o), on 14 September 2023, the AEMC published the *Draft Opportunity Cost Methodologies Consultation Paper*[2] (Consultation Paper) on the valuation methodology that it proposes to apply to SHL's opportunity cost claim.

Consultation only occurs for opportunity cost claims and not for direct cost claims. The AEMC's 'current view' on SHL's opportunity cost claim are outlined in Section 2, as context for this paper.

Baringa Partners LLP (Baringa) was engaged by SHL to provide advice regarding the position conveyed by the AEMC in its Consultation Paper. Baringa was requested to consider, in the context of the Guidelines and SHL's original claim, the appropriateness of the methodology proposed by the AEMC to assess the value ($/MWh) of the opportunity cost of the affected generation units. Baringa was not engaged to:

- undertake an audit of documentation submitted by SHL to the AEMC to support SHL's claim for direct costs and opportunity costs (AEMO has independently assessed the materials)
- assess SHL's claim for direct costs
- reflect on the opportunity cost generation quantity (MWh) in question, or
- take a view on either the appropriateness of SHL's bidding approach or its contracting strategy.

[1] AEMC, Compensation guidelines, Final guidelines, 21 October 2021, available at: https://www.aemc.gov.au/sites/default/files/documents/final_amended_compensation_guidelines.pdf.
[2] AEMC, Draft Opportunity Cost Methodologies, Consultation paper, 14 September 2023, available at: https://www.aemc.gov.au/sites/default/files/2023-09/AEMC APC Draft opportunity cost methodologies 20230914-wcover %282%29.pdf.

2 The AEMC’s current view on SHL’s opportunity cost compensation claim

The AEMC’s Consultation Paper, published on 14 September 2023, responds to the opportunity costs compensation claim made by SHL. The Consultation Paper considers two other compensation claims which are not part of Baringa’s engagement and therefore not considered in this report:

1. claim for direct costs made by SHL, and
2. claim made by Sunset Power International.

The AEMC considers:

- SHL’s eligibility to make an opportunity cost compensation claim
- the quantity of generation for the claim, and
- the value of that quantity.

SHL is eligible to make a claim

To make a claim for compensation for opportunity costs, a claimant must demonstrate that it is subject to a technical or commercial limitation which results in scarcity of its capacity or resource, such that delivering energy to the market during the APP could impact its capacity to deliver electricity at a different time.

The AEMC has accepted that SHL was subject to a technical limitation with respect to water licence limits. SHL is therefore eligible for opportunity cost compensation under this provision.

The quantity in SHL’s compensation claim has been accepted, while both the value and the basis used to determine this value is disputed

While the AEMC has accepted the quantity of generation for which SHL is seeking opportunity cost compensation, the AEMC has not accepted the price component (value in $/MWh) of the claim.

SHL submitted a $/MWh value for the opportunity cost of its affected generation units based on the cost of running their other (non-affected) generators – Colongra, Laverton and Valley Power – at a later (post-APP) point in time due to energy constraints on SHL’s affected generation units at that time. SHL’s basis for this valuation is that, as SHL needed to maintain a given level of output to defend its contracted volumes, less generation from its affected generation units meant commensurately more generation from its three gas and diesel units. In its valuation of opportunity cost of its affected generation, SHL included fuel and start-up costs for its three gas and diesel units.

As mentioned, the AEMC accepts the energy constraints faced by SHL’s affected generation units, but disputes the basis for SHL’s valuation of opportunity cost and, in turn, the valuation itself. The AEMC draft assessment sits within the context of the Guidelines, which set out a ‘hierarchy of principles’ (hierarchy) for selecting a method for valuing opportunity costs. The hierarchy is as follows:

1. **Market-based valuation:** The preferred method is to use a market-based valuation of an alternative that, over the relevant period of time, would justify an opportunity cost. The claimant should develop a counterfactual based on what would have occurred in the market had the claimant's behaviour changed and had it chosen the more profitable alternative opportunity.
2. **Previous market values:** If an appropriate market-based valuation is not available then the claimant should consider using market values over a similar past period; and
3. **Claimant methodology:** If it is not possible to use either of the above valuation methods, the claimant should develop its own methodology to value the opportunity costs.

Specifically, the AEMC's current view is that[3]:

- *SHL's method is not the preferred method for valuing opportunity cost specified in the Guidelines – the preferred method is a market-based approach.*
- *SHL has not demonstrated that an appropriate market-based valuation is not available to value its opportunity costs.*
- *SHL has not demonstrated any compelling reason why the Commission should depart from the Guidelines in this respect.*

The AEMC considers SHL's opportunity cost methodology to be a 'cost-based approach' (described also as a replacement cost approach) and therefore is not the preferred method. That is, it sits on the third tier in the hierarchy.

The AEMC proposes to calculate the opportunity cost by drawing on a volume-weighted average price estimate from the two weeks preceding the APP. This proposed methodology aligns with the second tier in the hierarchy.

[3] AEMC, Draft Opportunity Cost Methodologies, Consultation paper, 14 September 2023, p. ii, available at: https://www.aemc.gov.au/sites/default/files/2023-09/AEMC APC Draft opportunity cost methodologies 20230914-wcover %282%29.pdf.

3 The bidding behaviour of energy-constrained plant

The opportunity cost compensation claim for SHL needs to be considered in the context of how energy-constrained plants, which include pumped hydro and hydro units (collectively, ‘stored hydro’), bid their capacity into the spot market. The focus in this report is on spot power markets with uniform first-price auction designs (also known as ‘pay-as-clear’ markets), which was the design in place for the NEM during the APP of June 2022 (and remains the design at the time of writing).

In such markets, a plant typically bids in its capacity as per the following highly simplified approach:

- a portion of their capacity is bid in at the price floor, with this amount typically reflective of the plant’s minimum stable loading (MSL), which represents the level of a plant’s inflexibility,
- where contracts have been entered into, the plant bids *contracted* capacity at the plant’s explicit short-run marginal cost (SRMC)[4] to ensure the plant is dispatched so as to earn spot market revenues to defend their contractual positions,
- the plant’s *uncontracted*, or excess, capacity is bid in at or above the plant’s explicit SRMC depending on two types of energy scarcity (that is, the difference between supply and demand):
    1. The plant’s energy limitations (plant-specific scarcity), and
    2. system-wide scarcity.

  The higher the degree of scarcity, plant-specific and/or system-wide, the greater the extent to which an energy-constrained plant’s bid price exceeds its explicit SRMC, with the greatest uplift seen when there is a high degree of both plant-specific and system-wide scarcity.

For the sake of simplicity, and without loss of generality, we have ignored other important drivers of bidding behaviour, namely network constraints and the allocation of negative price risk under contracts.[5]

Where a plant has *contracted* capacity, the capacity it bids will reflect those contractual positions. In economic terms, what matters for a contracted plant is not its spot market revenue alone, but rather the net revenue earned from both spot and contract market activities. A plant may bid its above-MSL capacity below its explicit SRMC if doing so decreases costs that would otherwise have been incurred by failing to defend its contracted volumes.

[4] These costs include fuel costs and other variable operations and maintenance costs, but excludes opportunity costs. We use ‘explicit’ here to differentiate periods where SRMC includes opportunity costs from those when it does not.
[5] Network constraints and contracts which allocate all negative price risk to contract buyers can incentivise a plant to bid *all* of its capacity at the price floor. This was discussed in more detail in Baringa’s previous report for SHL, available at https://www.aemc.gov.au/sites/default/files/2021-12/ERC0341 Rule change request pending.pdf.

3.1 Energy-constrained plant and shadow bidding

Energy constraints can and do occur across a wider range of plants than just SHL's affected generation units, such as coal- and gas-fired generators. Indeed, as documented by the Australian Energy Regulator[6] (AER) and others, the weeks preceding the APP were characterised by operational constraints on multiple NSW and Queensland coal generators due to fuel security-of-supply concerns from coal mine outages and constrained rail transportation (both due to heavy rain-induced flooding). These constraints contributed to the sustained and elevated nature of spot prices which ultimately led to the CPT being hit in June 2022.

Energy-constrained plants face a trade-off: if they generate more today, they will have less available to generate tomorrow. This then means their bids today reflect the value forgone from tomorrow's generation: an opportunity cost. The forgone value is dependent on the plant's expectation of system tightness in this future period ('tomorrow'), and so is bound between two values:

1. **A minimum value, reflecting when future system tightness is perceived as *low***: the explicit SRMC of the generator that runs *tomorrow* (aka 'future price-setter') to replace the energy not provided by the increased output today from the energy-constrained plant.
2. **A maximum value, reflecting when future system tightness is perceived as *high***: a price in excess of that in 1 above, potentially as high as the market price cap (MPC), to enable the future price-setter to recover its own fixed costs.

Both these values are termed 'shadow bidding' as the energy-constrained plant's bid 'shadows' the bid of the generator that replaces it in the bid stack, namely the next-most expensive generator. As the AEMC has noted since the first version of its Guidelines[7], a generator's SRMC should and does reflect its opportunity cost. As such, the SRMC of the future price-setter could be as high as the MPC[8], which in turn informs the shadow bid of today's energy-constrained plant.

Shadow bidding is consistent with how the AEMC defines opportunity cost in its Guidelines:

> *"The value of the best alternative opportunity for eligible participants during the application of a price limit event or at a later point in time. The opportunity cost is the foreclosure of this alternative opportunity to use scarce capacity or resources more profitably at the same point in time or at a later point in time."*[9]

Shadow bidding has been found to exist in a broad range of power markets around the world, as discussed in Section 4 below, and is especially applicable to energy storage systems such as pumped hydro and battery storage facilities. Due to their limited storage depth, energy storage systems are

[6] AER, June 2022 market events report, December 2022, available at https://www.aer.gov.au/system/files/AER June 2022 Market Events Report- FINAL VERSION - 14 December 2022.pdf.
[7] AEMC, The determination of compensation following the application of the Administered Price Cap, Market Price Cap, Market Floor Price or Administered Floor Price, Guidelines, 30 June 2009, available at: https://www.aemc.gov.au/sites/default/files/content/Compensation_Guidelines.pdf
[8] To enable price-setters to recover their fixed costs given an energy-only spot market design, the MPC in the NEM is set at a level that exceeds, by orders of magnitude, the explicit SRMC of even the most expensive (liquid fuel) generators.
[9] AEMC, Compensation guidelines, Final guidelines, 21 October 2021, p. 12-13

energy-constrained and, in normal market conditions, considered to be more energy-constrained than thermal plants.[10]

Furthermore, as noted above, plant-specific scarcity also influences a generator's bid: for a given level of expected future system tightness, a more energy-constrained generator would tend to bid up the price it offers its capacity, reflecting its higher opportunity cost.

3.2 Application to SHL's affected generation units

In the context of SHL's affected generation units, and as discussed in the AEMC's Consultation Paper, the AEMC accepted there were constraints on these units' operations during June 2022 related to SHL's water licence.[11] That is, during June 2022, SHL's affected generation units were more energy constrained than typical constraints resulting from the finite size of a pumped hydro's upper and lower reservoirs.

It is important to note that SHL's affected generation units sit within an integrated portfolio of generators that also comprises gas- and diesel-powered turbines that collectively defend contracts sold by SHL into the market, including to SHL's retailers: Red Energy and Lumo Energy.[12] As a result, in the case that one or more of the plants in SHL's portfolio is less able or unable to generate, then output from other generators within the portfolio will and are increased in order to defend SHL's contracted volumes.

When output from SHL's affected generation units were energy-constrained during the APP of June 2022, this meant more output from its gas and diesel units (Colongra, Laverton North and Valley Power) was needed to continue to enable SHL to meet its contracted volumes. This means the SRMC of SHL's three gas/diesel units is more than just a theoretical 'shadow bid' reference point for its pumped hydro units – less generation from its pumped hydro units today means more generation in practice from its gas/diesel units tomorrow. In this way, the integrated nature of SHL's generation portfolio explains, in Baringa's view, the approach adopted by SHL to value the opportunity cost for the affected generation units.

[10] Though, as we noted, coal mine and rail flooding during May/June 2022 highlighted the constraints faced by NSW and Queensland black coal generators.
[11] AEMC, Draft Opportunity Cost Methodologies, Consultation paper, 14 September 2023, Section 4, available at: https://www.aemc.gov.au/sites/default/files/2023-09/AEMC APC Draft opportunity cost methodologies 20230914-wcover %282%29.pdf.
[12] Snowy Hydro Limited, retail businesses website, available at www.snowyhydro.com.au/retail.

4 A market-based methodology for valuing opportunity cost

In Baringa's view, there are two primary methodologies for delivering a market-based valuation of opportunity costs for pumped hydro units that are consistent with the first element in the AEMC's hierarchy:

1. Shadow bidding, and
2. Revealed bidding.

4.1 Shadow bidding methodology

A shadow bidding methodology provides a simple market-based valuation methodology to estimating the value of pumped hydro capacity in the absence of the administered pricing event. This methodology puts that uncontracted capacity tends to be bid at prices following, or 'shadowing', the price-setting technology in the market; that is, benchmarking to the marginal generator.[13] While this methodology may not fully represent bidding behaviour in all circumstances, as discussed in Section 3[14], pumped hydro units are understood to engage in shadow bidding in the NEM, as well as in other liberalised electricity markets, for at least a component of their uncontracted capacity. As also noted in Section 3, the shadow bid is a function of both plant-specific and system-wide scarcity, and so can be as high as the MPC.

Calculating the shadow price for pumped hydro units, and thereby opportunity cost, is an exercise of identifying an appropriate marginal generator benchmark. This can be achieved, in the case at hand, by considering the following options:

- A representative OCGT plant using actual fuel costs for the operator from the relevant period, or
- Actual plants deployed at the margin in the relevant region (that is, replacement cost), where it can be established that the output from these plants offset, or replaced, the output from the (energy-constrained) pumped hydro units. This is discussed further in Box 1.

[13] In NSW, the marginal generator could be and is typically either a black coal-powered generator or an open-cycle gas turbine (OCGT). During the weeks preceding the APP and the APP of June 2022, NSW black coal generators were highly energy constrained due to coal security of supply of concerns, as noted by the AER, AEMC and others. This meant OCGTs and liquid fuel generators became the *de facto* price setter during this period, as these generators were less energy constrained though did certainly see sharply higher fuel prices.

[14] Namely, when network constraints and contract structures are taken into account.

BOX 1: REPLACEMENT COSTS APPROACH

SHL's original compensation claim drew on the SRMC of gas and diesel generation units to calculate the value of the opportunity cost. This approach, drawing on replacement costs, was considered a cost-based methodology by the AEMC.

Considering replacement costs is relevant primarily to operators that have a portfolio of assets and optimise use across those assets. The advantage of this approach is it reflects actual decision-making with respect to how individual plants are bid in and operated as part of an integrated generation portfolio. However, this approach requires knowledge that the portfolio exists and how individual units are operated within it, which is more challenging for outsiders to know.

This portfolio consideration more strongly links the bids of energy-constrained plants, such as SHL's affected generation units, to the generation cost of more-expensive generators. However, such considerations are *not* a pre-requisite to the existence of shadow bidding; shadow bidding can and does occur by non-integrated, standalone, energy-constrained plants, as evidenced by the breadth of evidence documenting the prevalence of shadow bidding in multiple power markets regardless of the degree of horizontal and/or vertical integration.

Nevertheless, the replacement costs identified by SHL represent the opportunity cost of its affected generation units within their portfolio and during the APP, providing a reasonable proxy for shadow bidding, and thereby represent a market-based valuation of opportunity cost.

The alignment between the SRMC of pumped hydro and gas generation, through shadow bidding, has been recognised as a feature of NEM bidding, including by the AEMC, AER and ACCC.

4.1.1 Recent AEMC decisions supporting OCGT-based shadow bidding by pumped hydro units

The AEMC's final determination in 2018 regarding the Participant Compensation Following Market Suspension rule was informed by the shadow bidding of pumped hydro units.[15] The AEMC identified that an SRMC-based methodology to compensate pumped hydro for losses during a market suspension would 'give a low SRMC estimate that does not reflect the value of water held in storage and thus is not an appropriate value to be used for the purpose of calculating compensation.' As an alternative, the AEMC suggested 'the benchmark values for hydro and large-scale batteries be set by reference to the values applicable to gas plants in the same region.' For pumped hydro units with a capacity factor less than 40% (such as, the affected generation units), the AEMC suggested this be based on OCGT benchmark values.[16]

[15] AEMC, National Electricity Amendment (Participant compensation following market suspension) Rule 2018, ERC0225, November 2018, p37.
[16] Note that the final rule requires that AEMO will calculate annual benchmark values used for market suspension compensation in accordance with the NER and a published methodology, and does not require AEMO to implement the AEMC's suggested methodology for pumped hydro and battery generation.

We note the market suspension context is distinct from the APP. However, the principle that OCGT pricing is a reasonable proxy for pumped hydro bidding is nonetheless relevant to the APP opportunity cost discussion.

More recently in 2023, the AEMC considered the application of gas benchmarks for estimating the value of storage in the Directions Paper on Improving Security Frameworks. Here, the AEMC again noted 'gas benchmarks may be suitable for estimating the value of hydro storage' and is currently consulting with stakeholders on whether this compensation approach should be applied for energy and market ancillary service directions.[17]

4.1.2 Other views on pumped hydro shadow bidding

In line with these AEMC comments, there are other similar references to shadow bidding by hydro units by market bodies. The AER has previously noted that hydro offers 'are closely linked to gas and black coal offers'[18] and that 'a hydro generator's bids into the market will be closely linked to the bids of other generators. As a result, when the bidding levels of coal or gas generators increases, the implied fuel cost of a hydro generator may also increase.'[19] While the ACCC noted 'the practice of shadowing thermal generators', in the context of hydro generators.[20]

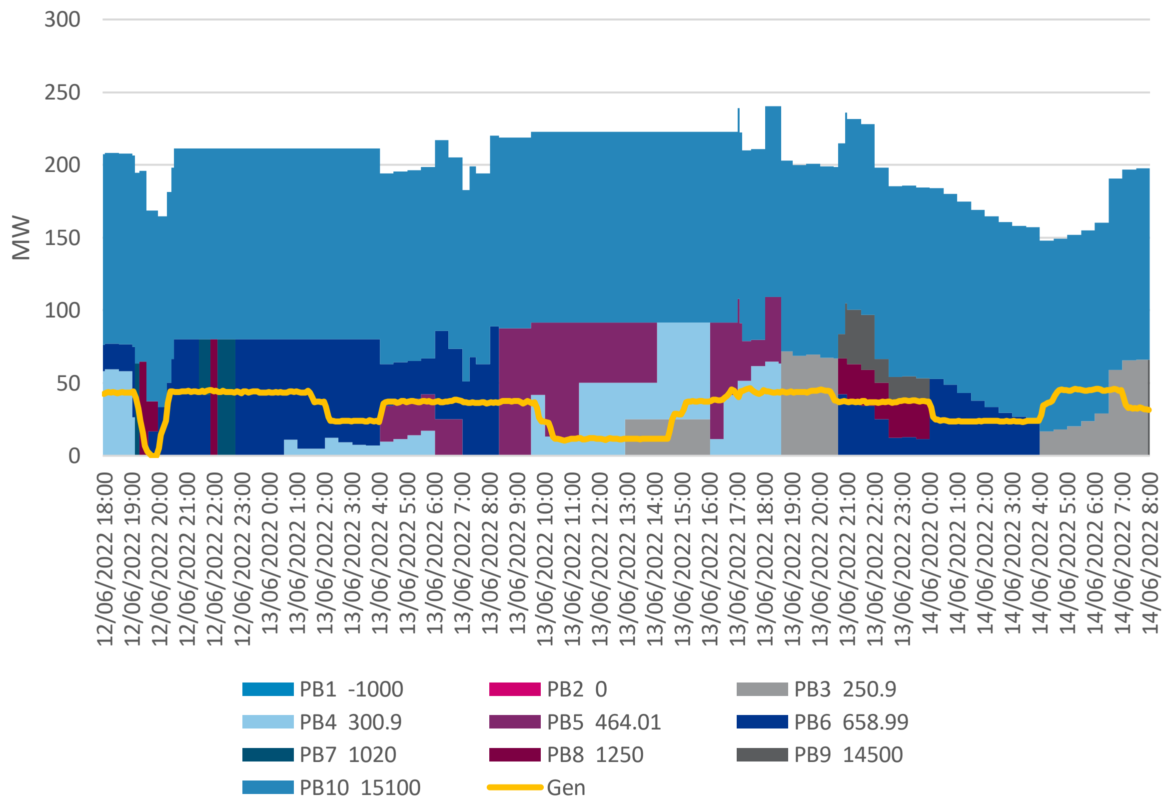
Beyond the NEM, the shadow bidding of hydro and pumped hydro assets has been acknowledged in other markets internationally, for example:

> *"These generators are not at the margin, but some can change their output and push another generator with a higher bid to the margin, hence, setting prices indirectly. A prime example of such behaviour is the role of Norwegian, and to a lesser extent Swedish, hydropower plants in the Nordic region."*[21]
>
> *Based on analysis of European power markets: "Given that [hydro] plants have only a limited amount of water that can be discharged within a year, the usage hours are optimised to serve the highest priced hours. Economists mention that the opportunity costs of releasing water are equal to the expected future value of electricity produced when referring to this non-marginal costs-based dispatch (Faria and Fleten 2011; Pikk and Viiding 2013). With regards to hydro-storage plants or pumped-hydro storage plants, the term "price setting" can thus be misleading since shadow prices—reflecting the marginal costs of additional alternative (thermal) power plants—are used for the dispatch."*[22]

[17] AEMC, National Electricity Amendment (Improving security frameworks for the energy transition) Rule 2023, ERC0290, Second Directions Paper, August 2023, p. 102
[18] AER, Wholesale electricity market performance report – December 2022, December 2022, p. 2
[19] AER, AER electricity wholesale performance monitoring NSW electricity market advice, December 2017, p. 20
[20] ACCC, Restoring electricity affordability & Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report, June 2018, p. 75
[21] Zakeri et al. 2023. The role of natural gas in setting electricity prices in Europe. Energy Reports. Volume 10, p2778-2792
[22] Blume-Werry, Faber, Hirth, Huber, Everts. 2021. Eyes on the Price: Which Power Generation Technologies Set the Market Price?, *Economics of Energy & Environmental Policy*, Vol. 10, No. 1, p. 4

The practice of shadow bidding can be seen in the bidding behaviour of SHL with the affected generation units during the APP. The Murray power station can be used as an illustrative example, as seen in Figure 1 below. The bids of the Murray power station are shown between 18:00 12 June 2022 and 08:00 14 June 2022. During the evenings of the 12 and 13 June, when system-wide scarcity was higher due to a lack of solar output and higher demand, relative to sunlight hours, a greater proportion of the pumped hydro unit's generation capacity is bid at $610.9/MW (PB 6).

Figure 1 Illustrative example of shadow bidding using Murray power station during the APP



Source: Data provided by SHL to Baringa. Data reflects the units in generation mode only.

As further discussed in Section 5, $610.9 (PB6) corresponds approximately to the calculated SRMC of a representative OCGT during this period.

This illustrative example accords with the views of the AER, ACCC, AEMC and academic studies, on shadow bidding being a feature of how pumped hydro bids its (uncontracted) capacity. As such, a shadow bidding-based methodology to opportunity cost assessment would, in Baringa's view, feature at the top of the AEMC's hierarchy with respect to adopting a market value-based methodology to determine an energy-constrained plant's opportunity cost.

4.2 Shadow bidding methodology underpins storage investment cases

Shadow bidding is more than just a theoretical concept, it also has practical relevance in the sense that decisions to invest in, or finance, storage assets – such as pumped hydro and batteries – rely on modelling of arbitrage revenues that apply shadow bidding behaviour. In Baringa's experience banking the Genex Kidston pumped storage project, as well as multiple battery storage projects, both debt and equity investors consider shadow bidding to be the basis for how storage bids.

Moreover, the benchmark generator is projected to change going forward and over time, from OCGTs to fast-start aeroderivative turbines and reciprocating engines – plants that are capable of ramping up to full output from a cold start within five minutes – for two reasons:

1. Relative to conventional OCGTs, fast-start gas plants are a better complement (that is, a better form of 'firming') to the increasing penetration of variable renewables projected to occur in the NEM given decarbonisation/Net Zero commitments by both governments and private entities.
2. To replace the firm capacity lost from the exit of incumbent coal and gas plants.

As technologies and their respective roles in the market change over time, as will the SRMCs that other assets are shadow bidding.

4.3 Revealed bidding methodology

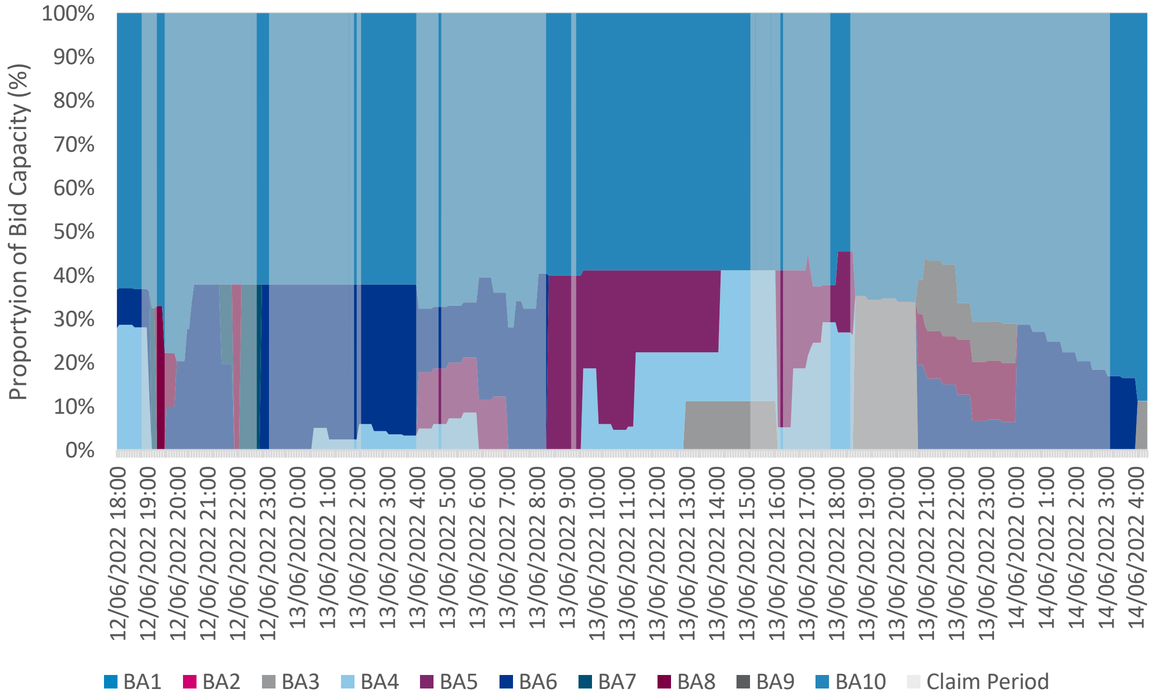
The opportunity cost of SHL's affected generation units can also be determined using the actual bid data of these units during the APP, given the availability of this data. Using actual bid data to quantify the opportunity cost of an energy-constrained plant provides:

- a practical assessment of opportunity cost to both test and complement theoretical arguments around shadow bidding linked to an OCGT's SRMC,
- a more dynamic and real-time assessment of opportunity costs and shadow bidding than a less dynamic approach based on a static or time-invariant SRMC of an OCGT. In particular, it is possible to discern the *range* in opportunity costs, in terms of magnitude and frequency; as noted in Section 3, the opportunity cost can range from the explicit SRMC of the future price-setter all the way up to the MPC, and
- a richer assessment of the extent to which non-shadow bidding considerations impact bidding behaviour, such as the impact of network constraints and contract considerations.

These advantages of using actual bid data could be offset by the disadvantage of potential 'gaming' during the APP – in particular, energy-constrained plants could reallocate more of their capacity into very high price bands (that is, bands well in excess of the future price-setter's explicit SRMC) during the APP in order to then claim compensation for opportunity costs on the basis of these inflated prices. This risk of 'moral hazard' would be less likely to occur if bidding behaviour, as borne out by actual bid data, did not change between the APP and non-APP periods.

The bid data across the relevant period can be drawn on to reflect on this point using the Murray power station as an example. In Figure 2 below, we can see that the proportion of capacity bid across bands by the Murray power station, at the times when the APC came into effect and out of effect (as the CPT was no longer reached), does not appear to be correlated with increased capacity in higher bands.

Figure 2 Murray power station bidding pattern across imposition of the APC during June 2022



Source: Data provided by SHL to Baringa. Data reflects the units in generation mode only. Shaded areas reflect settlement intervals when the APP was in effect.

As noted in Section 3, the AEMC's definition of opportunity cost refers to the "opportunity to use scarce capacity or resources more profitably *at the same point in time…*" (emphasis added). This means the revealed bidding methodology should ideally draw on data contemporaneous to the relevant period, reflecting actual plant-specific scarcity at that time.

For the purposes of the opportunity cost claim during the APP, the relevant data covers the settlement intervals from 12 June 2022 to 15 June 2022, in those periods where the APC was in effect, using the settlement price that would have occurred if the APC had not been binding. This counterfactual 'what-if?' spot price exists because NEMDE continues to operate during an APP. The APC is a price cap, not also a price floor. This means if the spot price during the APP, prior to imposition of the APC, was less than the APC, then this would be the spot price used for settlement during the APP. As such, the focus is on those settlement intervals during the APP where the APC was binding; that is, the intervals in which the 'what-if?' price exceeded the APC.

As further discussed in Section 5, there are two approaches to determining the 'what-if?' spot price for SHL's affected generation units:

1. Focusing on those settlement intervals where SHL's affected generation units were the price-setter, and averaging the 'what-if?' price across all of these intervals, over the APP. In this way, the revenues that would have been earned but for the imposition of the APC are revealed.
2. Using all settlement intervals where the APC was binding, not just those where SHL's affected generation units were marginal.

In Baringa's view, the first approach is superior to the second, as the former is more tightly linked to the affected generation units' opportunity costs. In summary, by using actual data from the relevant period, the potential revenue earned can be disentangled from the period of price administration, highlighting the opportunity cost.

4.4 Other methodologies

There are other methodologies to valuing opportunity cost. In Baringa's view, all of these would be considered as either tier-two or tier-three within the AEMC's hierarchy. As such, each of these methodologies are only discussed briefly below.

4.4.1 Using non-contemporaneous prices

This methodology takes the volume-weighted average price (VWAP) for the affected generating units over a time period other than the time period over which the units were considered to be energy-constrained for the purposes of assessing the opportunity cost claim. This approach then assumes this other time period is representative of the constraints on the generator during the claim period.

The AEMC used this approach in its Consultation Paper, basing it on the two-week period prior to the start of the APP in each of NSW and Queensland. The AEMC argued the advantage of this approach was that it revealed the price SHL's affected generation units were willing to receive, and in turn revealed their opportunity costs. However, there are two key issues with this approach:

1. The prior period is, by definition, not as representative of the energy constraints facing SHL's affected generation units, relative to the contemporaneous period. The Consultation Paper does not discuss why the two-week period prior to the start of the APP is more representative of the affected generation units' energy constraints and in turn their opportunity costs, than the contemporaneous period during the APP itself.
2. Related to 1 above, the AEMC's own definition of opportunity cost relates to "the same point in time or at a later point in time", and excludes any mention of a prior point in time.

An alternative methodology would be to use the affected generating units' VWAP for a "later period of time", as per the AEMC's definition of opportunity cost. In the context of SHL's opportunity cost claim, this would be a post-APP time period. However, Baringa considers this would also be an inferior methodology relative to using prices during the APP (the contemporaneous period), based on the 'what-if?' price as discussed above. In Baringa's view, there is no guarantee that the later period would be as representative of, let alone more representative of, the energy constraints ('plant-specific scarcity') of SHL's affected generating units during the APP.

4.4.2 Using only the MPC

As noted in Section 3, the opportunity cost for energy-constrained plants, like pumped hydro units, depends on expected future system scarcity, which at its most extreme would result in the opportunity cost being the MPC. However, Baringa does not recommend using the MPC to value the opportunity cost of SHL's affected generation units. This is because, while these units did consistently bid some of their capacity at the MPC during the APP (for example, in the case of Murray plant, see Figure 1), it was rarely the case that this capacity set the 'what-if?' spot price.

Put differently, the 'what-if?' spot price during those settlement intervals where the APC was binding was typically well below the MPC. This occurred in settlement intervals where SHL's affected generation units were the price-setter as well as intervals where other generators set the 'what-if?' price.

5 Opportunity cost values

Section 4 discussed methodologies for determining the opportunity cost for SHL's affected generation units. This Section quantifies each of these methodologies.

5.1 Shadow bidding methodology

We use three different estimates of the SRMC for the price-setting generator:

1. A representative OCGT plant with a heat rate of 13GJ/MWh and a gas price of $50/GJ. The $50/GJ gas price is the actual average price paid by SHL subsequent to the APP ending, as per the documentation provided by SHL to Baringa under this engagement.
2. The actual generation cost for SHL's gas and diesel units. This cost includes the actual volume-weighted average fuel cost of $44/GJ (averaged across gas and diesel costs) paid by SHL during the APP, and actual plant start-up costs. These costs represent the actual cost to SHL from replacing the generation from SHL's pumped hydro units with their gas and diesel units, as provided in SHL's original claim to the AEMC.

We consider the actual generation costs of SHL's gas and diesel units to be linked to the opportunity cost for SHL's affected generation units for two reasons:

1. Gas and diesel units are typically the future price-setter for energy-constrained plants and as such the bids of energy-constrained plants are set with reference to gas and diesel units' generation costs, as per Sections 3 and 4.
2. The cost of replacing the output from SHL's affected generation units with SHL's gas and diesel units represents more than a theoretical reference point but rather the cost in practice, given SHL operates a generation portfolio of assets, as discussed in Section 3.2.2.

In short, and as discussed further in Section 6, we consider SHL's submission of generation costs for its gas and diesel units to be consistent with the first element in the AEMC's hierarchy for opportunity cost calculation. The shadow bidding behaviour by energy-constrained plants like pumped hydro is what enables the generation cost for gas and diesel units to then be a market value-based methodology for determining the opportunity cost.

5.2 Revealed bidding methodology

We estimated the actual opportunity cost faced by SHL during the relevant, contemporaneous period including intervals from 12 June 2022 to 15 June 2022 using the settlement price that would have occurred if the APC had not been binding. This was undertaken using two approaches:

1. Time-weighted average price (TWAP) for the marginal megawatt at the volume-weighted balance of the affected generation units. That is, the marginal megawatt price revealed by SHL's bidding as seen through the partially-unfilled bids for SHL within the bid stack.
2. TWAP of the regional reference prices (market clearing prices) during the relevant period had the APC not been applied. That is, the price that would have been received for the next

megawatt generated, and therefore the unrealised opportunity. This approach uses the regional reference prices for Queensland and NSW and presents them separately.

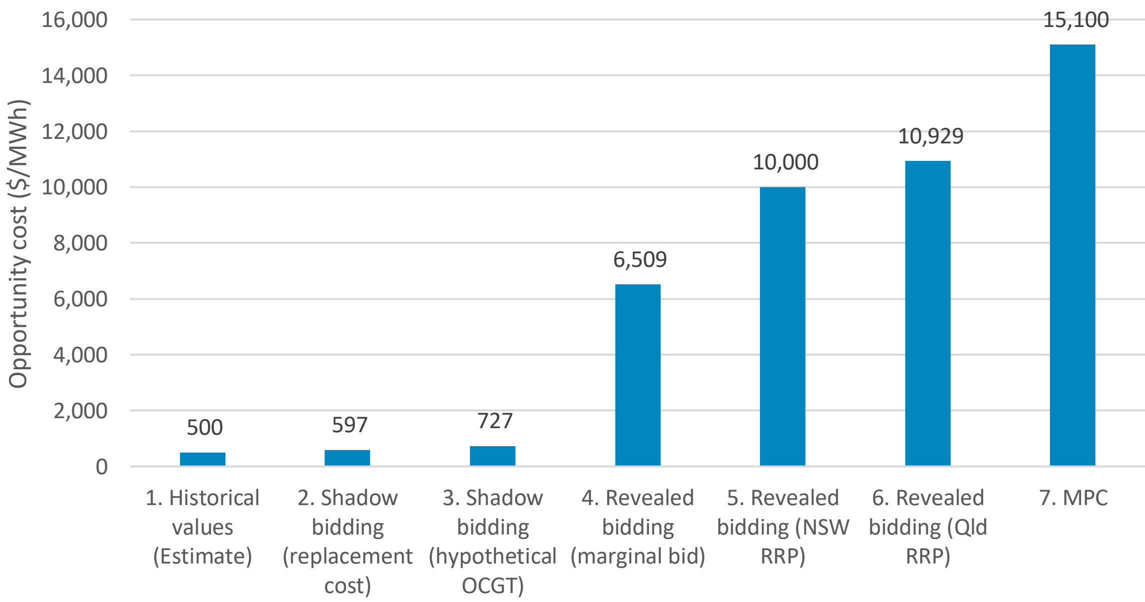
We consider the calculation in 1 above is superior to 2 because the revealed marginal price in 1. is more representative of SHL's bidding behaviour and therefore more tightly linked to opportunity cost than 2.

5.3 Using non-contemporaneous prices and MPC

The non-contemporaneous price, considering past market values, is the methodology proposed by the AEMC. This is calculated using a VWAP that SHL received for its affected generation units for the 14 days prior to the APP (29 May – 12 June 2022). We have provided an estimate of this price at around $500/MWh.[23] Meanwhile, the MPC in June 2022 was $15,100/MWh and can be used to estimate the highest potential opportunity cost driven by the value of the loss of load.

5.4 Summary

Figure 3 Alternative opportunity cost values for SHL's affected generation units



The prices discussed in the preceding subsections are shown in Figure 3 above, with the prices laid out in ascending order. Item 1 represents an estimate of the price using the non-contemporaneous prices methodology, as adopted by the AEMC. The shadow bidding methodology is represented at items 2 and 3. Here, item 2 is the price included in SHL's original claim representing the actual

[23] Baringa has included this in the chart to enable comparison with the other values. However, as we were not provided with the value used by the AEMC, we have denoted our value with "Estimate" as this may not equal the value proposed by the AEMC in its Consultation Paper.

subsequent cost of replacing the generation from their pumped hydro units with their gas and diesel units with an average fuel cost of $44/GJ. While item 3 is the price for a hypothetical OCGT was developed by adopting the assumptions provided by AEMO[24] and using fuel price of $50/GJ (the actual average price paid by SHL subsequent to the APP).

Continuing on, the revealed bidding methodology is shown in items 4, 5 and 6. Here, in item 4, the price represents the average marginal price for the affected generation units on a time-weighted basis if the APC had not been applied. While items 5 and 6 show the TWAPs across the APP, in NSW and Queensland respectively, had the APC not been applied. Finally, item 7 is the MPC that was in effect during June 2022.

[24] AEMO, 2023 Inputs, Assumptions and Scenarios Report, Final Report, July 2023, available at: https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf?la=en.

6 Conclusion and further considerations

The AEMC's Guidelines state that a market-based valuation is preferred when calculating opportunity cost compensation claims. We have argued an appropriate market-based value for the opportunity cost of pumped hydro can be based on:

- shadow bidding the next most-expensive generators (typically, OCGT plants), or
- actual bidding behaviour during the period of scarcity,

with these two methodologies yielding the same result when hydro bids in line with shadow bidding.

Consequently, we consider there is a shortcoming with each of the two arguments put forward in the Consultation Paper with respect to the AEMC's current view on the deficiency of SHL's opportunity cost claim, as follows:

1. *Argument 1*: the AEMC considers SHL's opportunity cost claim to be a direct cost-based methodology rather than a market value-based methodology, as it is based on the direct costs of SHL's gas and diesel units.

   We consider this AEMC argument to be lacking because, as outlined in this paper, energy-constrained plants, like pumped hydro, bid at the SRMC of the 'future price-setting' generator, that is gas and diesel plants, representing their opportunity cost. For SHL, this link is made clearly within their integrated portfolio of assets, as the explicit SRMC of SHL's three gas/diesel units is more than just a theoretical 'shadow bid' reference point but a marker in practice. We therefore consider SHL's replacement costs for its gas and diesel units to be consistent with the first element in the AEMC's hierarchy.

2. *Argument 2:* related to 1 above, the AEMC then proposed a market value-based methodology using prices over a historical period, pre-APP. The AEMC notes, which we agree with, that this methodology is second on the hierarchy.

   We consider this AEMC methodology to be lacking relative to using contemporaneous-period prices, namely the 'what-if?' settlement price when both the APC was binding and SHL's affected generation units were the price-setter.

Despite the merits of revealed bidding, we see shadow bidding as a better methodology. The objective of the administrative pricing framework is to provide appropriate compensation for generators during periods of very high scarcity whilst also protecting the financial interests of electricity consumers. For this reason, providing compensation for opportunity cost based on both plant-specific and (extreme) system-wide scarcity, which is what a revealed bidding methodology is likely to provide, may not align with the objective of the administrative pricing framework.

In contrast, a shadow bidding-based methodology for stored hydro which takes account of OCGT *explicit* generation costs would reflect the hydro plant scarcity, but not system-wide scarcity by virtue of not including opportunity costs in the SRMC of OCGTs and in turn in the bids of stored hydro.

For these reasons, we therefore consider a shadow bidding-based methodology for opportunity cost valuation to be better than a revealed bidding-based methodology.

SHL's original claim, a shadow bidding-based opportunity cost value of $597/MWh, can be compared against the following three alternative opportunity cost values, each of which use a methodology based either on shadow-bidding or revealed-bidding:

- *Shadow bidding:* $727/MWh, representing a hypothetical OCGT using actual fuel costs at the time of the June 2022 APP.
- *Revealed bidding*: $6,509/MWh, representing the "what-if?" price set by SHL's affected generating units when the APC was binding.
- *Revealed bidding*: $10,000/MWh representing the "what-if?" price when the APC was binding regardless of whether or not SHL's affected generating units were the price-setter.

SHL's original claim sits on the lower end of the spectrum of these alternative opportunity cost values. Given the merits of the shadow bidding methodology and the position in *Argument 1*, we would support this methodology, and other shadow bidding-based calculations.

Further considerations for the AEMC

Baringa suggests the AEMC may wish to consider providing greater clarity within the Guidelines regarding the AEMC's view on *how* to determine opportunity costs under preferred market-based approach because it currently leaves room for ambiguity.

This said, we note there are legitimate differences in opportunity cost estimation even when a market value-based approach is adopted (that is, even when the first element in the AEMC's hierarchy is used), as per the discussion in Sections 4 and 5. For this reason, we support the AEMC's view that one cannot be overly prescriptive with respect to pinning down exactly what the opportunity cost of energy-constrained plants would be in each and every instance.

If, and when, the AEMC updates the Guidelines in terms of expressing *how* to determine opportunity costs under the preferred market-based approach, we suggest the AEMC could consider aligning the Guidelines with the thinking undertaken by the AEMC (and other market bodies) in other documents, such as the Security Services Directions Paper regarding the shadow bidding approach.

Annex 1: List of abbreviations

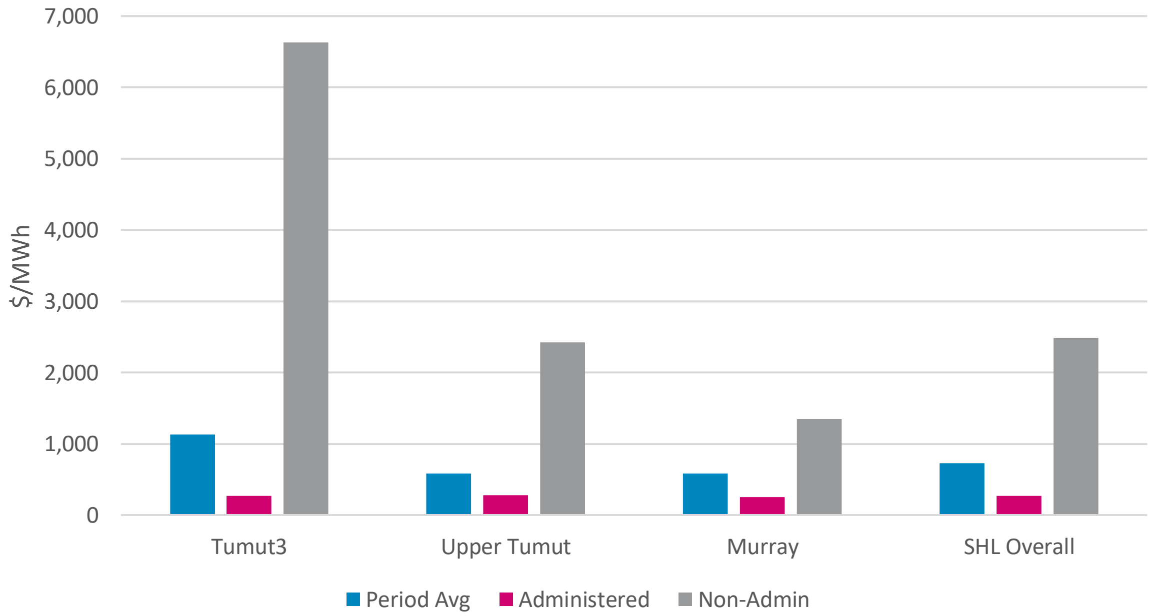
Abbreviation	Full title
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
APC	Administered Price Cap
APP	Administered Price Period
Consultation Paper	*Draft Opportunity Cost Methodologies Consultation Paper*
CPT	Cumulative Price Threshold
Guidelines	*Compensation Guidelines v4*
MPC	Market Price Cap
MWh	Megawatt hour
NEM	National Electricity Market
NER	National Electricity Rules
NSW	New South Wales
OCGT	Open-Cycle Gas Turbine
SHL	Snow Hydro Limited
SRMC	Short Run Marginal Cost
Stored hydro	Energy-constrained pumped hydro and hydro-electric plants
TWAP	Time-Weighted Average Price
VWAP	Volume-Weighted Average Price

Annex 2: Supplementary analysis of opportunity cost values

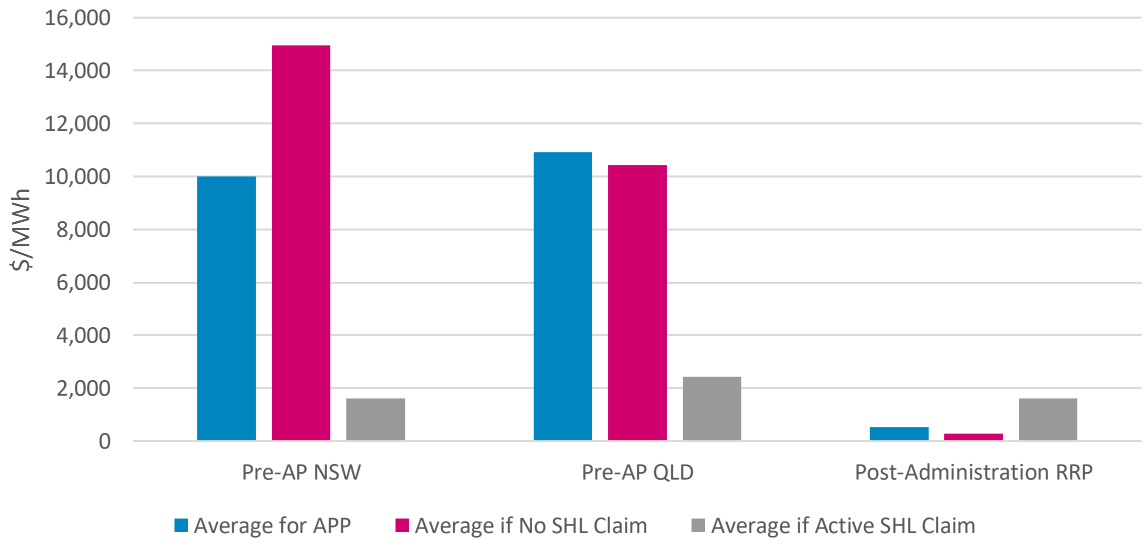
Annex 2.1 **Comparison of VWAPs for the all affected generation units across 12-15 June where the APC in effect or not**

Settlement intervals during the APP	VWAP ($/MWh)	Description
All intervals	724	VWAP across all intervals regardless of whether the APC was binding or not
Intervals where the APC was binding	267	VWAP across all periods where the APC was binding
Intervals where the APC was binding	2,482	VWAP across all periods where the APC was not binding

Annex 2.2 **Comparison of VWAPs for each affected generation units across 12-15 June where the APC in effect or not**



Annex 2.3 **Comparison of the regional reference prices in NSW and Queensland during the APP if the APC was not in effect**



Annex 2.4 **Comparison of the revealed marginal TWAP for each affected generation unit (and in total) during the APP**