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Dear Commissioners

Compensation and dispute resolution frameworks — Draft rule determination — 30 November 2023

EnergyAustralia is one of Australia's largest energy companies with around 2.4 million electricity and gas accounts across eastern Australia. We also own, operate and contract a diversified energy generation portfolio across Australia, including coal, gas, battery storage, demand response, wind and solar assets, with control of over 5,000MW of generation capacity.

We appreciate the opportunity to provide input on the Commission's draft determination. As we have raised with Commission staff, it would be useful to consider how different costs arising in a directions situation would be treated under the draft rules. Several stakeholders already presented examples in submissions to the Commission's issues paper, with the Commission subsequently clarifying categories of costs that are and are not compensable, with reasons for each (see tables 3.1 and 3.2. of the draft determination).

We have further questions on the valuation of gas for the purposes of determining direct costs, including costs of deprival. Gas can be stored, in specific storage facilities and as linepack. Participants make decisions to purchase, store and release gas over different timeframes, as well as replenish volumes in anticipation of future market conditions. From a retail perspective we manage our own risk exposures and primarily act to ensure our customers' needs are satisfied. The incentives we face align with ensuring supply adequacy across the East Coast Gas System (ECGS) in that we want to avoid being short to our customers' demand and so exposed to high prices (up to market price caps) and ancillary payments under the different declared gas markets. Like all prudent trading entities in the ECGS, we anticipate uncertainties over the short and medium term and so have rights over certain reserved volumes of gas in storage, but seek to minimise this relative to our retail load.

The rules drafted for directions compensation under the ECGS reflected those in place for the Victorian Declared Wholesale Gas Market (DWGM). As the Commission is aware, energy ministers established the ECGS framework in haste[1] as a response to the events of winter 2022 and concerns that they might be repeated. During the winter 2022 crisis, participants were seen to withdraw offers (in gas and electricity markets) in managing

[1] Regulatory amendments to extend AEMO's functions and powers to manage east coast gas supply adequacy | energy.gov.au

their own portfolio risk. The AER has stated this was in response to "distorted price signals" (i.e. the imposition of administered pricing, which prevented scarcity bidding) but also concerns regarding fuel limitations as gas storage levels approached critical levels in spite of ongoing winter demand, with shortfall notifications extending until the end of September.[2]

An example or repeat of winter 2022 events would involve the market being subject to administered pricing **early** in the season, with a participant directed to supply a large volume of gas into the ECGS. The direct cost here could arguably be either the $40/GJ (i.e. the Administered Price Cap), or the purchase cost of the participant's gas (perhaps $20/GJ). Following that, issues in the market are resolved and administered pricing is lifted. Then **later** that winter there is another scarcity event with market prices reaching the market price cap ($800/GJ). The previously directed participant no longer has gas in storage and cannot defend their position against the market price cap. In this scenario the 'direct' cost (up to $40/GJ) is significantly inadequate.

This type of situation may be rare however reflects what we expect to arise where AEMO exercises its directions power, namely an intervention that compromises the ability of directed participants to manage their own risk exposures. Affected participants would have to, perhaps in a short timeframe but not immediately, replace the volume of gas that was directed into the system by AEMO. Each participant will be different in terms of the degree of contractual obligations held over this gas volume, including for transport and other services, in addition to hedging and other risk exposures. These all need to be considered when valuing any gas and associated directions compensation from a price and timing perspective.

In this context we recommend the Commission consider whether there should be additional guidance in the rules on how various costs in this situation and potentially others would be treated. The drafting of rule 704 (based on the DWGM) refers to direct costs being estimated by reference to market or contract prices, otherwise standing or benchmark values as set out in the procedures. It is not clear that the use of market or contract prices would be preferable in every circumstance, or whether there would be a clear distinction between observable and benchmark prices. Generally there could be scope for the rules to set out principles or objectives of the type being applied by the Commission (including for electricity compensation), namely consideration of incentive effects and administrative burden when selecting between market, contract and benchmark rates, as well as these values at different points in time.

In the situations where AEMO directs gas to be taken out of storage and injected into the ECGS, our reading of the relevant rule provisions and the Commission's draft determination is that:

- The rules discuss direct costs as those associated with providing the service that was the subject of the direction, for example the cost of the gas being injected. One interpretation is that this reflects the price at which that volume was purchased, requiring consideration of gas inventories, which effectively would be a benchmark or average price drawn from contract information. It may be open for AEMO's procedures to establish a standing methodology, similar to the 90th percentile used in the case of electricity, which minimises administrative burden

[2] AER, *State of the energy market 2023*, p. 157.

and provides clear incentives by being prescribed well in advance for all situations.

- The Commission also refers to direct costs incurred for buying "replacement gas".[3] This would seem to refer to purchases from the relevant spot market or under contracts held by the directed party. However there is no guidance on selecting between procurement options that might be available, and more importantly the time period that might apply. Purchases made in the wake of a scarcity event would, given new information and prudent practices, likely diverge from simply matching the directed volume, which may impact on price.

- the rules allow compensation for direct costs associated with the deprival of services subject to direction, but only where the entity is liable for payment under a relevant contract or by law. The Commission considers this does not apply in examples involving forward-sold electricity from gas-powered generators or LNG contracts, deeming these types of losses to be consequential.[4] As it relates to the deprivation of stored gas volumes, the Commission should clarify that direct 'deprival' costs are allowable in a situation where volumes cannot be replaced in time to meet a committed future contractual obligation. The Commission should also provide further justification for its view regarding the scope of liabilities arising under a "relevant contract or otherwise by law" under rule 704, noting that both gas generators and LNG exporters are natural gas industry facilities or relevant entities within the law definitions that apply to the ECGS.

The Commission should elaborate on its decision to exclude opportunity costs in part on the basis of avoiding complex and costly counterfactual assessments. As highlighted above, the determination of direct costs will likely involve detailed and complex assessment of the prudent risk levels and portfolio management by each directed entity, and their decisions to replace gas volumes using different procurement options and over varying timeframes. Principles could be inserted into the rules that require compensation claims to be The Commission has also proposed to increase the threshold for making claims to $50,000 such that any administrative burden should already be more proportional to the importance of the claim being assessed. The Commission is seeking to expressly prohibit behaviour that exacerbates the direct costs of any entity who might lodge a compensation claim. The effect of this on direct costs would be measured relative to a counterfactual where the participant did not engage in that behaviour.[5] Subject to our recommended changes below, this assessment would likely involve legal complexities and costs beyond the value of any underlying claim. Again this appears to be inconsistent with the exclusion of opportunity costs on the grounds of administrative burden.

The Commission's primary justifications regarding compensable costs relate to setting appropriate incentives. Specifically, prospective directed entities should act in ways that support the normal operation of the market, rather than seeking or preferring a directed state. The strength and effect of incentives depends on having clarity on the specific treatment of costs, as well as on the circumstances that give rise to directions. This is reflected in the Commission's statement that "participants must consider the risk of a

[3] AEMC, *Compensation and dispute resolution frameworks – draft rule determination*, 30 November 2023, p. 16.
[4] ibid.
[5] ibid., p. 23.

direction alongside other risks alongside other risks associated with market participation…”.[6] We have various observations on this for the Commission’s further consideration:

- the rules do not, and likely will not, prescribe in detail how direct or other specific costs are to be valued. The extent of discretion in how costs are assessed ex post adds uncertainty, and this is a natural deterrent to incurring them in the first place.

- there is some uncertainty whether or how ECGS directions would interact or take precedence over directions in the existing declared gas markets. To the extent they apply outside such markets, there could be a higher reliance on benchmark or standing prices.

- The recently established framework under Part 27 does not provide for any objective measures by which participants can assess the likelihood and degree of AEMO interventions. AEMO’s procedures do not contain sufficient detail on which participants can form such expectations.[7] This contrasts to the NEM’s LOR thresholds measured with respect to reserve levels.[8] We note the development of reliability settings for the ECGS is still being considered.[9]

- The ECGS directions would also sit alongside other interventions like the Australian Domestic Gas Security Mechanism, AEMO’s trading powers under part 27 and in relation to Dandenong LNG.

The Commission states that the following incentives should arise where consequential costs for LNG exporters and gas generation are disallowed:

- in the process of managing portfolio risk, exporters should sell marginally less LNG cargoes where the market is in distress to mitigate that risk and the increased risk of direction

- generators should allow for gas supply risk and plant outages in the process of participating in the electricity contract market. Gas directions are a subset of the contracting risk that should be allowed for by participants in the process of selling electricity forward contracts.[10]

The Commission’s expectation appears to be that participants should hold excess gas volumes relative to their own risk exposures. At the same time, participants are only expected to be compensated for direct costs in the event these reserves are called upon and in ways that are unclear. Where gas is held by suppliers in excess of their own needs, it would tend to be uncontracted and hence outside the proposed scope of ‘deprival’ compensation. Overall these compensation settings would seem to deter prudent action by individuals to anticipate and hence take actions to avoid supply shortfalls.

[6] ibid., pp. ii, 6.
[7] East Coast Gas System Procedures (aemo.com.au) – see section 3.1.1
[8] External Procedures Template Mar 2015 (aemo.com.au)
[9] Consultation on Stage 2 of the Reliability and Supply Adequacy Framework for the east coast gas market | energy.gov.au
[10] AEMC, p. 18.

The uncertainties in when and how AEMO directions, amongst other interventions, would impact on participants makes it difficult to determine whether any aggregate holdings of gas reserves would be at an efficient level, i.e. such that the risk to the ECGS is balanced against the holding costs of these reserves, in line with customer willingness to pay. Absent a transparent reliability and security framework, it otherwise seems likely that participants would expect AEMO to take a greater position in the market, particularly given conservatism and political pressure to maintain supply adequacy at any cost. Again (and nothing this is outside the scope of gas compensation settings) this seems likely to result in individual participants under-contracting relative to prudent levels from a system-wide perspective.

The Commission's proposed prohibition on behaviour that exacerbates direct costs under a direction would apply to acts or omissions that are intentional or reckless. The Commission proposes these be classed as a tier one civil penalty. Reckless behaviours are less serious than those with intent, and on this basis we consider they should be subject to a separate and lesser penalty tier. The maximum tier one civil penalty for a body corporate is currently over $11 million or 10 per cent of annual turnover. In any case, the Commission should provide further justification for why its recommended penalty tiers would be proportional to the quantum of direct cost claims (noting the minimum claim threshold is to be increased from $5,000 to $50,000) and associated detriment to the market should these be exacerbated.

If you would like to discuss this submission, please contact me on 03 9060 0612 or Lawrence.irlam@energyaustralia.com.au.

Regards

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