Shell ENERGY

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RE: Gas Market Parameter Review 2022

Shell Energy welcomes the opportunity to comment on the review of market parameters for the DWGM and the STTM. We appreciate the timeliness of the review and the inclusion of considerations around linkages between the DWGM and STTM.

About Shell Energy in Australia

Shell Energy is Shell's renewables and energy solutions business in Australia, helping its customers to decarbonise and reduce their environmental footprint.

Shell Energy delivers business energy solutions and innovation across a portfolio of electricity, gas, environmental products and energy productivity for commercial and industrial customers, while our residential energy retailing business Powershop, acquired in 2022, serves more than 185,000 households and small business customers in Australia.

As the second largest electricity provider to commercial and industrial businesses in Australia[1], Shell Energy offers integrated solutions and market-leading[2] customer satisfaction, built on industry expertise and personalised relationships. The company's generation assets include 662 megawatts of gas-fired peaking power stations in Western Australia and Queensland, supporting the transition to renewables, and the 120 megawatt Gangarri solar energy development in Queensland.

Shell Energy Australia Pty Ltd and its subsidiaries trade as Shell Energy, while Powershop Australia Pty Ltd trades as Powershop. Further information about Shell Energy and our operations can be found on our website here.

General Comments

Shell Energy considers that the events of June 2022 reveal the extent of dislocation that can occur as a result of disparate market parameters. Whilst we acknowledge the range of factors that contributed to the market outcomes in June 2022 we believe the misalignment of price settings between the different gas markets played an important role. The misalignment of price settings between the NEM and the gas markets led to inefficient dispatch outcomes within the NEM leading to high levels of AEMO market intervention. Divergent price cap and cumulative price threshold (CPT) levels and different calculation methodologies for the CPT between the DWGM and the STTM resulted in inefficient injection and withdrawal outcomes within the gas markets. The difference in timing and period of price cap application between the DWGM and the STTM was also problematic.

Harmonising the market parameters and ensuring they remain effective in the context of a highly dynamic international energy market is a difficult task that we don't believe can be fully achieved by the current review. However, we are supportive of work towards this goal. Ultimately we believe that the market reliability (price) settings for the NEM, and the market parameter settings for the DWGM and the STTM need to be considered together under a robust

[1]By load, based on Shell Energy analysis of publicly available data.

[2] Utility Market Intelligence (UMI) survey of large commercial and industrial electricity customers of major electricity retailers, including ERM Power (now known as Shell Energy) by independent research company NTF Group in 2011-2021.

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consultation approach carried out by an independent body such as the Reliability Panel. This would ensure that market settings are co-optimised to maximise the benefits for consumers across the energy value chain.

With regard to the DWGM and STTM it is Shell Energy's view that harmonisation of parameters between markets is crucial to ensure orderly outcomes during times of system stress. The current misalignment of cumulative price threshold (CPT) and market price cap (MPC) as well as the different calculation methodology between gas markets can lead to supply misallocation during times of simultaneous high demand. This misallocation results from price arbitrage between markets when price caps bind or when the CPT binds at a different time in each market. The resolution of these incentives would ensure that gas supply is allocated more efficiently at times when efficiency provides the most benefit to all stakeholders.

In assessing the alignment between markets, we encourage AEMO to not only look at price levels but to consider how the settings are calculated and applied. For example, the use of more frequent pricing intervals in the CPT calculation for the DWGM allows for harmonisation of the CPT through variation in the calculation period based on the daily average price while keeping the CPT level fixed. Alternatively, the current calculation method could be retained whilst adjusting the CPT to reflect its use of the cumulative sum of five pricing outcomes. Whatever method is chosen there must be consistency between the market parameter setting across all the gas markets.

Response to Consultation Questions

Question1: Do you have any comments on the appropriateness of the calculation of acceptable risk?

Shell Energy considers that markets operate most efficiently when price dynamics provide sufficient flexibility for participants to responsibly manage their risk exposure. Targeting a level of risk by participant type may unnecessarily constrain market price settings and restrict the market from providing efficient resource allocation and levels of investment. In particular, the 500 days of profit risk measure proposed in the consultation document does little to accommodate the assessment of investment needs against the highest marginal value of gas usage. Constraining the market by this measure across a range of participants is more likely to ensure that the investment signals provided in the model can only be matched to lower value gas consumption. This is unlikely to lead to efficient outcomes in the long term.

The 500 days of lost profit approach leads to further assumptions by participant type that are not detailed in the information provided for consultation. The modelling team needs to assume levels and type of contracting by participant type. It is unclear what these levels or types of contracting will be or whether the historical basis that will be used is appropriate for the expected future market environment. Participant contracting approaches change in response to market outcomes over time and it is unclear how this dynamic will be considered in the modelling.

Another major assumption is the profitability of each participant type for various parameter levels. The proposed approach to use aggregate ABS data by industry will result in major generalisations about profitability and therefore the acceptable level of risk in the gas markets. Shell Energy sees this as a major weakness of the proposed risk measure.

Shell Energy suggests that a second round of consultation be conducted prior to the modelling being undertaken. This second round would set out the details of all assumptions being made by the modelling team to ensure that stakeholders are comfortable with the approach being taken. The modelling and market parameter outcomes would benefit from this approach as a second round of consultation would allow market participants to provide feedback on specific inputs rather than just the high level modelling approach.

Question 2: A range of scenarios to be studied are listed in Appendix A. Do you think any major scenarios are missing, or that any scenarios proposed are not relevant?

A key market development predicted by AEMO's Integrated System Plan step change scenario is the rapid retirement of coal fired generation within this decade. Shell Energy expects this to result in increased periods of high gas demand as a result of increased reliance on dispatchable gas powered generation (GPG). For the period under examination by this review it will be important to ensure that the gas markets can operate efficiently with the removal of substantial coal fired plant from the electricity market. We therefore support the range of scenarios that incorporate high GPG demand early in the period to ensure that investment needs are tested in an appropriate timeframe.

However, we do have some questions regarding scenarios 5A, 5B and 5C where demand is expected to exceed the 1:20 demand forecast for three consecutive days. We seek clarity to understand if such an outcome has occurred historically in any of the gas markets. We also note that in these scenarios the consultation document indicates that demand may also exceed normal contract/hedge limits. Shell Energy's considers that the types of contracting used by participants should also be carefully considered and documented. In our view contracting types should not be limited to simple fixed volume gas contracts.

Another factor driving increased gas fired generation will be the intermittency of wind and solar resources. We support the examination of a scenario in which low variable renewable energy (VRE) output in the NEM drives demand for gas through dispatch of GPG. Due to the interconnected nature of the NEM and the reasonably high correlation of VRE output across the NEM this scenario is likely to apply across all gas markets simultaneously and should therefore be examined as an interlinked market scenario.

Shell Energy would also like to better understand the relative weighting of the scenarios outlined in the appendix. It is not clear what approach is being used to differentiate between the least likely market outcomes and the more central sets of assumptions that might be expected to eventuate more often in the period under examination. Further detail and discussion with stakeholders in this area would be helpful.

Question 3: Are there any artefacts of the modelling approach that need to be further considered or are causing concern?

The consultation paper identifies the importance of constructing appropriate GPG bids but provides little detail. We note that bids will have a maximum price linked to what would be viable in the NEM but this highlights an important interaction that we don't believe has been sufficiently clarified by the modelling team. Are the NEM price levels assumed to be up to the NEM market price cap in all scenarios, or are assumptions made regarding the application of the NEM administered price cap? Is the treatment of NEM prices, and therefore GPG bids, different for different scenarios? Further detail on these questions and the assumed interaction between gas and electricity markets would be helpful for stakeholders seeking to better understand the modelling approach and potential outcomes.

The level of contracting by participant type will be a crucial set of assumptions for the modelling. We understand that this information is constructed from historical bidding behaviours. We note the difficulty this approach poses in accurately reflecting the market conditions to be examined in each scenario, particularly where the exact circumstances may not have occurred previously and are therefore not reflected in the historical data. Additional information about the approach to contract level construction would be helpful for participants and stakeholders to help assess the modelling approach.

We also note that the modelling holds contracting levels and potentially contracting types constant across all cases. This appears to be an inappropriate assumption given the historical responsiveness of participants to the market environment. The likely outcome from this approach is that the market settings are over-constrained due to the inflexibility of contracting between scenarios.

We consider the set of participant types to be included in the modelling to be broadly appropriate. However, the contribution of each customer type and their relative influence on the modelling outcomes over time is not clear. For example the small market customer type is assumed by Market Reform to have a "less sophisticated approach to risk management". Shell Energy believes this type of market participant will be strongly incentivised to evolve their risk management approach over time if the market becomes increasingly risky. This dynamic does not appear to be captured by the modelling approach. We consider this a shortcoming of the model and note that it would be very likely to play a role in modelling results that inappropriately shield participants from risk and under-incentivise investment in the industry.

Question 4: Do you agree that the cost of investment should be based on an LNG import terminal or some other option?

Shell Energy supports the use of an LNG import terminal as the most likely marginal investment to provide additional supply and address any potential supply shortfalls at peak demand times. We note that the consultation paper proposes assessing other income streams available to the facility as a contribution to its viability under various market parameters. It would be helpful for stakeholders to understand the value streams to be assessed and the assumptions to be made about their relative revenue contributions to the project being modelled.

Shell Energy also notes that the selection of capacity factor allocated to the LNG import terminal will be a critical assumption with regards to recovery of capital, yet the modelling paper contains little in the way of detail regarding this. We consider this to be a significant shortcoming in the modelling and further detail and discussion with stakeholders in this area is warranted.

Question 5: Are the investment costs and operating life reasonable estimates with respect to investment in an LNG receipt facility?

The investment costs outlined in the consultation document appear to align with market expectations for such a project. However, the investment revenue assessment for an LNG import facility is proposed to consider 1 in 10 year events for return purposes. We note that this does not align to the high demand day assumptions in the scenarios being modelled. The 1 in 10 year assumption for events under an investment assessment should be aligned with the 1 in 20 assumption being used for high demand days in the modelling.

The consultation document allocates an expected facility life of 30 years to the LNG import facility. We consider that the 30 year period is too long given the forecasts of future gas usage and consider that 20 years should be the maximum expected facility life.

Question 6: Recognising that that the Investment Cost Data presented above must apply across a range of industries and participant types, the investment under consideration is anticipated to be used infrequently and primarily for the purpose of addressing transitory gas market events rather than long term re-equilibration, and investors will consider long term funding costs:

- *Does the equity market risk premium for the sector (6.80%) represent a reasonable long term average?*
- *Does the combination of the risk-free rate (3.01%) and the debt margin (2%) adequately reflect the average cost of debt (5.0%) expected to apply over the project life?*
- *Is the overall estimate of post-tax real WACC (4.72%) reasonable bearing in mind it is applicable to a facility anticipated to be used infrequently?*

Shell Energy's view is that the investment project being considered should be assessed as a standalone project. It is unclear therefore why the investment parameters need to apply across a range of industries and participant types. As a standalone project we would expect the equity risk premium and debt margin to be substantially higher given the risk profile of such a project. A post-tax real WACC of 4.72% is very closely aligned to the 4.7% proposed by

Transgrid in its 2023-28 revenue proposal[3]. We do not believe a commercially developed floating LNG terminal should be assessed on comparable cost of capital terms to regulated transmission investments.

Question 7: Do the range of the grid points seem reasonable?

Shell Energy supports a wide range of grid points being examined by the modelling. We note that under high international pricing conditions the upper bound for the APC may be close to the LNG netback cost in some circumstances. It may therefore be appropriate to examine an APC above the proposed upper bound to assess market risk and efficiency in unconstrained circumstances. Similarly, the $1000 MPC level assessed in previous reviews may now be relevant despite being found "far from acceptable" in previous reviews.

With regards to the values set out in Table 4, we note that it retains the inconsistency of values between the DWGM and the STTM. Shell Energy considers that the levels for the MPC and CPT between the various gas markets must be consistent and if a different calculation methodology is to be used for calculating the CPT in the DWGM, then the level of CPT for the DWGM must be consistent with the CPT proposed for the STTM.

We also note that the granularity of the grid points to be examined is limited. To ensure that market efficiency can be maximised within appropriate risk bounds we suggest that granularity be increased. More appropriate settings could be: APC intervals of $5/GJ across the proposed range, CPT intervals of $100 and, MPC intervals of $100 in both markets.

With regard to the NEM APC to be used, Shell Energy supports assessing the proposed $500/MWh but notes that it may be necessary to undertake the modelling with a range of levels given the uncertainty in this parameter. A range of APC levels have been proposed under a NEM rule change which is currently being considered by the AEMC. Assessing a range of NEM APC levels from $300/MWh to $800/MWh would provide insight into the impact of the final determination and enable this review to respond to the outcome of the AEMC review.

Other Issues

An important issue indirectly encompassed by this consultation is the disparate market outcomes following the triggering of retailer of last resort (RoLR) in one or more of the gas markets. Currently, different provisions apply between the different gas markets leading to inefficient market outcomes. Shell Energy supports AEMO reconsidering these outcomes. It is our view that consideration should also be given to whether any specific provision should apply at all, noting that no provisions currently apply in the electricity markets when a RoLR event occurs.

We note that changes to the provisions regarding a RoLR event in the DWGM will require changes to AEMO's Wholesale Market Administered Pricing Procedures (Victoria) and as the market parameters form part of the Procedure, changes could be facilitated as part of this consultation. However, we note that changes in this area for the STTM will be subject to a rule change to Part 20 of the National Gas Rules to remove subclause 428(d), we consider that AEMO is best placed to commence consultation in the area with stakeholders and submit any rule changes arising from this consultation.

For any questions regarding this submission please contact Peter Wormald (peter.wormald@shellenergy.com.au).

Yours sincerely,

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[3] https://www.aer.gov.au/system/files/Transgrid%20-%202023-28%20Revenue%20Proposal%20-%2031%20Jan%202022%20-%20PUBLIC%20-%20NEW.pdf