Shell ENERGY

8 November 2021

Ben Hiron
Australian Energy Market Commission
GPO Box 2603
Sydney NSW 2000

Dear Mr Hiron

RE: Primary Frequency Response Incentive Arrangements

Shell Energy Australia Pty Ltd (Shell Energy) welcomes the opportunity to respond to the Australian Energy Market Commission's (AEMC) primary frequency response (PFR) incentive arrangements draft determination.

About Shell Energy in Australia

Shell Energy is Australia's largest dedicated supplier of business electricity. We deliver business energy solutions and innovation across a portfolio of gas, electricity, environmental products and energy productivity for commercial and industrial customers. The second largest electricity provider to commercial and industrial businesses in Australia[1], we offer integrated solutions and market-leading[2] customer satisfaction, built on industry expertise and personalised relationships. We also operate 662 megawatts of gas-fired peaking power stations in Western Australia and Queensland, supporting the transition to renewables, and are currently developing the 120 megawatt Gangarri solar energy development in Queensland. Shell Energy Australia Pty Ltd and its subsidiaries trade as Shell Energy.

www.shellenergy.com.au

General comments

Shell Energy, (previously known as ERM Power) has been a willing and active participant in the journey over the last six years to develop a market-based solution to correct the decline in power system frequency control. We have participated in the Australian Energy Market Operator's (AEMO) original Ancillary Services Technical Advisory Group (ASTAG), the AEMC's Technical Working Group processes and through submissions to each stage of the process to develop a market-based framework for the enduring provision of PFR services.

Shell Energy is largely disappointed in the AEMC's draft determination on primary frequency response incentive arrangements. Chiefly, we consider that the Commission should not have produced a draft determination at this stage but instead should have delivered a second Directions Paper or an Options Paper. This is because we consider there are a range of issues and complex design elements in the draft determination which remain poorly defined and have not been previously discussed in the AEMC consultation documents or the AEMC's Technical Working Group (TWG) on PFR. We believe that the AEMC's TWG process could have been better utilised to develop and test a range of options that could meet AEMO's technical requirements for frequency response while providing market-based signals for the provision of narrow-band PFR.A market-based approach

[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 2011-2020.

to provide enduring incentives for the provision of PFR enjoys wide industry support. In contrast, the AEMC's option proposed in the draft determination entrenches mandatory obligations rather than looking to market-based solutions. We therefore believe it is premature at this stage for the AEMC to recommend a single pathway forward through a draft determination for the provision of PFR.

Further, based on the GHD report and the Australian Energy Market Operator's (AEMO) Technical White Paper on enduring PFR arrangements that accompany the draft determination, it is clear to Shell Energy that the draft determination does not set out an enduring solution for the ongoing provision of PFR. These supporting documents make it clear that the requirement for PFR is in a state of flux, with the potential for both an increased need for and a declining supply of PFR over the coming decade. In essence, it appears that AEMC, with support from AEMO, is recommending a solution that may only be effective in the short and possibly medium term.

AEMO's Technical White Paper states that the likely exit of synchronous plant over the coming decade will reduce the available supply of headroom, foot room and stored energy[3] required for the provision of readily responsive PFR. Battery Energy Storage Systems (BESS) are only obligated to provide mandatory PFR when providing active energy output to the Energy market, so there is no guarantee that PFR from BESS will be available to fill the role currently filled by synchronous generators absent an effective market-based framework. While we understand most BESS have continued to supply mandatory PFR even when charging or at rest, in Shell Energy's view the proposed framework may well incentivise BESS to modify control systems to ensure PFR is not supplied unless generating active energy.

Semi-scheduled variable renewable energy (VRE) generators which are financed by long term power purchase agreements (PPA) based on metered output[4] are not incentivised to provide frequency response services if doing so results in reduced output and direct loss of both energy and large-scale generation certificate (LGC) revenue. Costs associated with FCAS or rewards for supplying FCAS are so small in comparison that they simply don't warrant a change from maximising output based on available input energy for VRE generators as it is the PPA contract prices (energy and LGCs), rather than the regional reference price (RRP) on which their revenue is primarily based.

At the same time, there will likely be an increased need for PFR due to the increase in variable output renewable energy generating units and increasing responsiveness of generation and load to wholesale spot market prices as a result of the recently implemented Five Minute Settlement rule change. Indeed, AEMO sets out that targeted procurement of PFR may be required at some point. While AEMO may be internally factoring in the provision of PFR headroom via use of the unit commitment for security or the system services market framework, such an outcome would be a poor result. In fact, the draft determination in section 5.2 actually foreshadows such an outcome and the use of market intervention through the use of Clause 4.8.9 Directions or the unit commitment for security or the system services market framework to maintain sufficient reserves (headroom) for the provision of PFR.

> *"The Commission notes the provision of sufficient PFR in the power system is further reinforced by AEMO's ability to intervene in the market to maintain power system security. AEMO may intervene in the market and issue directions to market participants, where such directions are necessary to maintain or return the power system to a secure, satisfactory or reliable operating state."*[5], and
>
> *"Furthermore, the Commission is in the process of assessing two rule change requests that propose additional arrangements for the scheduling and procurement of essential system services for system*

---

[3] From here in our submission collectively referred to as headroom

[4] It should be noted that unlike standard hedge contracts, metered output contracts only generate contract for difference payments based on actual generating unit output.

[5] AEMC Primary Frequency Response Incentive Arrangements Draft Determination p74

> *security. These arrangements would explicitly put in place arrangements to value, procure and schedule essential system services that aren't otherwise provided through spot markets, allowing these to be provided at lower cost to consumers and more transparently."*

These comments suggest the AEMC accepts the proposed PFR incentive framework is unlikely to deliver an enduring solution for the efficient provision of PFR. From a participant's perspective, this would represent a poor market design choice that will ultimately lead to increased costs to consumers.

While there are some positive elements to the draft rule change, overall, we consider that the draft rule fails to create on ongoing, long-term value for PFR. Unlike the overlay of the Energy Security Board's (ESB) post-2025 review of the National Electricity Market (NEM), which seeks to establish suitable market settings for the NEM over the long-term, the draft determination sets out a short-sighted solution for PFR. Given the proposed 27-month implementation timeframe, it would seem more reasonable to look at an enduring model that can achieve the aims of the PFR requirement over a range of possible futures in the long-term. Shell Energy is concerned that the proposed approach could result in implementing a system which may be redundant just a few years after its introduction. In our view the solution proposed in the draft determination fails to meet the ESB's reform objectives to establish suitable market settings for the NEM over the long-term.

We would prefer that the AEMC instead revise its recommendation and look to design an enduring set of arrangements for PFR. While we still believe that the current sunset provisions for narrow band mandatory PFR should be retained[6], we would accept a small extension to the sunset date if it resulted in the development of an enduring market-based PFR framework.

AEMC's proposed arrangements for PFR cannot be valued by potential providers in either operational or investment timeframes By continuing to impose mandatory narrow band mandatory PFR on generators without reserves to support its provision, the AEMC's proposed framework effectively reduces the volumes of contingency frequency control ancillary services (FCAS) reserves that may be available to respond as required to a sudden change in frequency due to contingency events. This could have a significant impact on power system security during a major non-credible contingency event. As the proposed framework for PFR provides no incentive for the provision of reserves (headroom) for the provision of mandatory PFR, the only place this headroom can be attained is via the appropriation of reserves currently procured to manage a contingency event(s). This outcome also creates a compliance uncertainty risk for generating units where it becomes unclear as to when reserves procured for contingency services were 'reallocated' for use by PFR.

The proposed framework is not an enduring solution

In reflecting on what is being proposed, it is in effect the provision of frequency control services achieved by the combination of PFR and secondary regulation response. However, only the latter has a market-based framework to incentivise its delivery. Shell Energy has previously noted in submissions that historically, the provision for both primary and secondary frequency response was the method for delivering frequency control until AEMO's predecessor, NEMMCo argued for and implemented a system whereby frequency (regulating) control services could only be supplied in response to the system operator's request for deviation away from an energy dispatch target via the central AGC system. AEMO has also continued this restriction on provision of regulation FCAS despite a number of requests to review this. Given the historical success of using both primary and secondary frequency response for frequency control, we consider this option should be explored to replace mandatory narrow-band PFR.

Shell Energy considers that our arguments put forward in previous submissions remain valid and the provision of frequency (regulating) control services should be allowed to be achieved by a service provider through the

---

[6] Noting Shell Energy's support for wider band mandatory PFR

combination of local determined primary frequency (regulation) response based on actual system frequency outcomes and secondary regulation (frequency) response dispatched by AEMO's AGC system.

AEMO has consistently argued that their system security requirements can only be met through the continued application of narrow band mandatory PFR on all generating units capable of its provision. Shell Energy considers that the available data indicates that a less onerous approach could deliver the same outcomes with a smaller impact on generators as a whole.

AEMO's own data indicates that effective power system frequency control was achieved by the end of November 2020 following only 16 of 53 Tranche One large thermal generating units implementing the narrow band PFR settings. After that, power system frequency outcomes indicated diminishing (if any additional) returns as additional generating units switched in narrow band PFR. While AEMO argues that this then results in lower response on each unit, we believe this is immaterial as the requirement is the observed response of frequency in the power system, not the movement on individual generating units. No significant observable change in power system frequency outcome was observed after implementing narrow band PFR setting on the initial 16 units.

AEMO's argument that narrow band PFR is required to ensure credible and non-credible contingency events are managed correctly, fails to include for contingency FCAS response, (provided reserves for this has not already been consumed by providing mandatory PFR), as well as support from wider band mandatory PFR[7] in response to larger contingency events. In addition, system frequency is also supported by contracted under or over frequency response protection schemes as well as mandatory under frequency load shedding on consumer load and generator output reduction, (or runback requirements), under generator performance standards for over frequency events.

AEMO also claims that mandatory narrow band PFR is necessary for geographic diversity of its provision. In our view, mandatory PFR has the opposite effect: by occurring purely as a by-product of which generating units have headroom, its geographic incidence will be quite random. The events of 25 August 2018 highlight this fact where the vast majority of available headroom resided on South Australian region generating units. This resulted in a trip of the Heywood interconnector due to the large response from generators in that region, following which, under frequency load shedding occurred in New South Wales and Victoria as units in those regions had little by way of operational headroom. In contrast, a market mechanism can readily specify maximum or minimum regional quantities and maintain the geographic diversity AEMO determines is necessary in a market-based framework.

With regards to our initial point that adding additional PFR-enabled plant delivered diminishing returns, Greenview Strategic Consulting notes in their report to the AEMC on the effectiveness of the implementation of mandatory PFR, and highlighted by GHD in their report[8]:

> *"The rapid reductions in the number of excursions outside of the band speaks to the effectiveness of implementing locally measured frequency responsiveness via narrow band PFR, rather than relying on AGC driven set point changes to maintain frequency within the NOFB. The rapid reduction of excursions also suggests that by December sufficient PFR was enabled to contain normal operating frequency within the NOFB, which may have implications on the volumes of PFR needed for effective frequency control."* and "*Adding additional PFR capacity beyond the amount available in December 2020 offers limited performance improvement.*"

[7] Noting Shell Energy's support for wider band mandatory PFR at a setting of +/- 0.40 Hertz

[8] GHD Enduring Primary Frequency Response page 24

Shell Energy considers the significant flaw in the currently proposed framework is the lack of provision of reserves (headroom) for provision of PFR. As noted in the GHD report[9] when discussing the proposed double-sided causer pays (DSCP) incentive framework:

> *"While DSCP will not provide certainty in relation to the volume or availability of frequency control services in the same way that an enablement market does"* and *"DSCP on its own can be effective while there are sufficient reserves of PFR available in the market."*

GHD then notes:

> *"Hence, it is yet to be seen whether DSCP would effectively incentivise sufficient frequency responsive plant and related reserves to meet system requirements when the proportion of thermal generation is substantially reduced from present levels, as is projected in forecasts.*
>
> *Looking further ahead, we see that there may be a need to establish stronger market arrangements that provide a greater level of certainty for system operation and send the right price signals to the market for provision of future PFR capacity (reserves)... At that time a PFR-FCAS type market to procure the necessary reserves to provide effective primary regulation will be necessary as we do not believe that there will otherwise be any assurance that sufficient responsive plant and available headroom to effectively maintain frequency during normal operation. Without such price incentives for future capacity and given the projected reduction in the level of synchronous generation we would expect a gradual degradation of system frequency performance to the level experienced prior to the AEMC's Rules change for mandatory PRR in mid-2020.*
>
> *At the same time, a procurement mechanism would provide increased operational certainty for AEMO to plan ahead for system control and security...*
>
> *The importance of ensuring sufficient PFR reserve is available cannot be understated and hence there is a need to value it.*
>
> *...Without sufficient reserve i.e. head- and foot room of units enabled for PFR, there will be limited or no contribution to correcting frequency deviations as PFR is subject to the unit being able to provide or absorb energy to counter the change in frequency"*

The GHD report makes it clear that the proposed framework will not provide an enduring outcome absent an effective framework for procurement of reserves. We believe this is a major flaw in the proposed framework. We are concerned that this could result in a need for further changes within a relatively short time period, potentially in the form of mandatory headroom requirements or other contractual arrangements with targeted service providers possibly using the system services market to rectify this flaw.

We recommend the AEMC reconsider their proposed framework and issue a revised draft determination toimprove the current proposal by implementing a less complex rule change which allows regulation FCAS to be provided by the combined provision of primary frequency (regulation) response and secondary regulation (frequency) response using the same pool of reserve procurement. AEMO would then be required to procure adequate reserves to facilitate the provision of both primary and secondary frequency regulating services. This would provide for more efficient provision of the required services, provide the correct incentive for its long-term provision and more accurate pricing of the costs of service provision than the currently drafted rule.

At a minimum, we strongly recommend this rule change requires a trial of the provision of regulation FCAS provided by a combination of primary frequency (regulation) response and secondary regulation (frequency)

---

[9] GHD, Enduring Primary Frequency Response, 16 September 2021, page ii and iii

response as a market-based response. To do otherwise consigns the NEM to a suboptimal framework that will require replacement in a relatively short timeframe.

Cost recovery framework

In considering the proposed cost recovery and payments framework, the draft rule still does not recognise the full suite of costs that mandatory narrow-band PFR imposes on generators. The resultant costs from the mandatory narrow-band PFR requirements on generators are somewhat tempered by the changes to causer pays factors, in which generators contributing to improving system frequency are rewarded via the proposed form of a DSCP framework through the introduction of so-called frequency performance payments. Reforms to the alignment and length of the sample and application period are positive in some areas but negative in others in that it can result in cost recovery obligations for non-active primary and secondary frequency response being imposed on participants who exhibit good frequency control performance.

The major issue as far as we are concerned is that generators will continue to face mandatory PFR requirements without necessarily being able to recover the costs that provision of PFR imposes on them. This includes both market losses incurred in the energy market as well as increased plant maintenance costs. Shell Energy's strong preference would be for an effective market-based system which would allow for generators to bid to provide both PFR services including its required reserves (headroom) at the lowest cost.

As we noted in our submission on the directions paper (submitted as ERM Power) the immediate costs to a generator, or other supplier, of providing either frequency control ancillary services (FCAS) or PFR can at times be significant, depending on prevailing energy and FCAS price outcomes. A generator maintaining headroom for the provision of contingency raise FCAS or generating at lower output levels when providing narrow-band mandatory PFR or lower regulation FCAS response at times when the energy market price is above the providers marginal cost, forgoes margin that would otherwise be accrued. Similarly, a supplier that maintains capability above minimum load to provide lower contingency or regulation FCAS foot room or generates at higher output when providing narrow-band mandatory PFR or raise regulation FCAS response at prices below marginal costs incurs a direct loss. This represents the immediately transparent cost of providing frequency control services, but not its total cost. In addition to this, increased costs for plant maintenance will occur over time. While these may be difficult to quantify immediately, it is clear there may be considerable costs in this area. While the revenue derived in the current FCAS markets compensates the provider for the provision of these necessary services, no such efficient market framework will exist for PFR under this draft rule.

We consider that the absence of an efficient market-based framework will not provide sufficient short- or long-term economic signals for providers to provide this capability. In order to ensure there will be sufficient providers of these required services in the medium- and long-term, the investment signals for this need to be put in place in the short-term to allow potential providers sufficient market data on which to base their decisions. While the proposed framework allows for net payments to generators that provide a net positive impact to system frequency to the active service, it also penalises these participants in the proposed cost recovery framework for the non-active service. Overall, the proposed framework is likely to be insufficient to change this.

Also of significant concern to Shell Energy, is that this proposed change to the cost recovery framework was conceived outside industry consultation or the AEMC TWG process and therefore the impact has not been fully considered and robustly reviewed.. We consider the proposed framework for the cost recovery of the non-active service to be flawed and recommend that instead the framework retain the current causer pays calculation framework for cost-recovery for the non-active service. This reflects that (secondary) regulation FCAS reserves must continue to be procured in a dispatch interval for the non-active service based on the historical performance of the power system including for the poor performance at times by some participants. Poor performance contributes to the need for the ongoing procurement of the non-active service. In our view, the cost recovery framework for the non-active service should continue to recognise this and align cost recovery with the cause or need for the service.

Shell Energy is somewhat supportive of the proposal to align and shorten the sample and application period for the active service to more closely align with a calculated party's (scheduled or semi-scheduled generating units or scheduled loads, etc.) more recent deviations in output or consumption that caused the need for active service response. However, we have a number of concerns with regards to the use of "real time" causer pays factors.

Under the proposed framework of a single interval calculation period, a participant which generally contributed to the need for PFR could temporarily withdraw from the energy market at times of high regulation FCAS prices to minimise costs. This is based on regulation FCAS prices being the pseudo PFR services price. This could have a negative impact on costs to consumers and fail to meet the NEO.

A significant number of real time causer pays factors are currently discarded in the causer pays factor calculation due to technical reasons. Any solution to allocate substitute discarded factors with a replacement factor will certainly result in a reduction in the nominal efficiency gains from the proposed change.

Taking these factors into account and the also the improvements in data processing capability from when the causer pays framework was first initiated in the NEM, we recommend the AEMC consider the implementation of a causer pays sample and application period of one trading day for the active service. The current trading day's causer pays factor would be based on a sample period from the trading day two days prior to the current trading day. AEMO would be required to calculate and publish the causer pays factors for the current trading day by 20:00 Eastern Standard Time on the immediately preceding trading day. Where greater than 25 per cent of dispatch interval data is discarded, the most recent accurately calculated causer pays factor will prevail. This change would:

- reduce the current lengthy temporal disconnect in the calculation and allocation of causer pays factors to more reasonably reflect a generating unit, or scheduled load current dispatch performance;
- capture sufficient dispatch interval data to allocate causer pays factors based on AEMO's assessment of the system need as the data would be based on a daily cycle;
- remove the incentive to withdraw from the energy market at times of high regulation FCAS prices;
- provide a reasonable solution to the issue of discarded "real time" factors due to technical issues; and
- ensure that cross subsidy between participants and market customers is minimised.

An effective market-based approach in this area would provide improved incentives for unit commitment and de-commitment decisions, as a generator with a portfolio of units would be incentivised to operate an additional unit to provide frequency control reserves and capability to respond across its generation fleet in return for being adequately compensated for providing these services. The currently proposed framework fails to provide an effective market-based approach. Our support for changes to the cost recovery provisions would be subject to a number of significant changes to the currently inaccurate AEMO causer pays calculation methodology.

Shell Energy also does not support the proposal to introduce a framework where the regulated "response requirement" used in AEMO's automated generator control (AGC) system would be the sole basis for an adjustment or multiplication factor to value PFR based on prevailing regulation FCAS prices. We do not believe the calculated regulated "response requirement" on its own is a valid benchmark as it fails to take into account the level of PFR that has already been supplied to achieve the existing frequency outcome. Frequency could be trending at a stable value of 50.00 hertz (Hz) which would result in a regulated "response requirement" of zero, yet hundreds of megawatts (MW) of PFR may have been supplied to achieve this outcome. It is the sum of these two that results in the maintenance of power system frequency at 50 Hz.

Shell ENERGY

Shell Energy recommends that to create some level of incentive for PFR provision, including reserves (headroom), the calculated regulation FCAS price adjustment ratio must be based on the AEMO calculated regulated "response requirement" plus the actual positive PFR provided, with the sum of these divided by the AEMO procured (enabled) regulated FCAS for the applicable dispatch interval. The adjustment ratio would always be allocated a minimum value of 1 so that positive PFR provision always received at least the regulation FCAS price.

Example:
Regulation FCAS enabled = 200 MW
Calculated regulation response requirement = 50 MW
Positive PFR Contribution = 550 MW
Calculated adjustment ratio = 3.000

Although this may still undervalue PFR, it is more representative of the value of PFR services relevant to the provision of regulation FCAS reserves. The price per MW of provided PFR would be capped at the regulated FCAS market price cap.

Consideration of and compliance with the frequency operating standard

Changes to the frequency operating standard (FOS), should be supported by economic and engineering arguments.Identification and consideration of risks to the power system, and the economic costs of the standard to mitigate risks should be the target for all frequency control objectives. This is not currently the case. In our view AEMO has sought to impose a frequency control objective through the AEMC rule change process, at significant economic cost to participants, an outcome well inside what the FOS sets out as acceptable. To date, AEMO has provided little in the way of engineering argument that the FOS as set by the NEM's Reliability Panel is deficient.

If AEMO believes the FOS is deficient, then we suggest that AEMO should make this case to the Reliability Panel, similarly to the approach adopted in the past, such as in 2001 when NEMMCo argued that from an engineering perspective power system frequency did not need to be maintained at all times under system normal conditions between 49.90 and 50.10 Hertz and an economic benefit could be achieved by relaxing the FOS. Many participants did not agree with the Panel's decision to relax the FOS, but at least it was an open and transparent process.

Shell Energy would welcome a transparent review of the FOS to determine if the FOS should be revised based on the standard being representative of the correct market-determined balance between conflicting priorities of engineering technical perfection and economic rationalism. Once revised, or not, the FOS must become the standard to which AEMO should be required to drive FCAS procurement to solely achieve frequency outcomes that meet that standard, rather than adopting an artificially high standard driven by mandatory PFR.

Other issues

We support the proposal to include metered non-scheduled generator dispatch deviations in the causer pays calculation on the proviso that non-scheduled generators would be able to minimise or remove causer pays cost via the provision to AEMO of intended dispatch targets on a dispatch interval basis and their adherence to these dispatch targets. We also recommend that the AEMC consider if, with metering improvements for five-minute settlement, large non-scheduled loads should have individual causer pays factors assigned to more accurately reflect their contribution to PFR requirements. For large, steady non-scheduled loads, such an outcome could reduce causer pays costs when compared to the current methodology based on the allocation of the residual factor multiplied by energy consumption and more accurately assign the residual costs to less stable loads which are a greater causer of frequency deviations.

Shell Energy also acknowledges the proposed change to allocate a portion of the residual component of the causer pays process to non-metered market generators. We understand that this would be based on metered output over a five-minute period. Shell Energy supports this change and recommends that it should also be extended to non-metered, non-market generators where energy output metering is available as fluctuations in output from these generators would also add to the need for PFR.

With regards to the treatment of asynchronously connected or islanded regions, we consider this could be simplified such that any local requirement should be recovered from generators and loads connected in the region or sub-region to which the local requirement applies on a causer pays basis regardless of network connection status. Global requirements would be recovered from all generators and loads on a causer pays basis.

Shell Energy supports a change to generating unit or scheduled load-based causer pays factors as opposed to the current portfolio-based causer pays factors. This would allow participants to identify poorly performing generating units or scheduled loads and determine if changes to operations are warranted.

We consider that causer pays factors for market network service providers (MNSP) should be calculated and the MNSP should be liable for cost recovery the same as for a generating unit or scheduled load based on the impact of their operations on power system frequency.

Shell Energy notes the draft rule would require AEMO to report on the level of aggregate frequency responsiveness on a quarterly basis as part of its existing report on quarterly frequency performance. Whilst we support such a change, we recommend that AEMO also be required to report on a monthly basis the level of effective headroom and foot room available for PFR at the time of daily maximum and minimum demand, which would exclude reserves enabled for both contingency and regulation FCAS response as well as BESS response at times of no active energy output. The calculation would also consider the impact of generating units ramping between energy targets as at times of ramping there may be limited stored energy available for the provision of raise PFR services. Similar to how AEMO reports weekly on the level of regulation FCAS procured and used on a dispatch interval basis, AEMO should be required to report weekly on the level of utilised PFR on a dispatch interval basis.

Conclusion

Shell Energy is largely disappointed in the AEMC's draft determination on primary frequency response incentive arrangements. The draft determination contains many issues and complex design elements which have not been previously discussed in the AEMC consultation documents or the AEMC's Technical Working Group on PFR. We believe that the AEMC's TWG process could have been better utilised to develop and test a range of options that could meet AEMO's technical requirements for frequency response while providing market-based signals for the provision of narrow-band PFR.

Based on the GHD report and the Australian Energy Market Operator's (AEMO) Technical White Paper on enduring PFR arrangements that accompany the draft determination, it is clear to Shell Energy that the draft determination does not set out an enduring solution for the ongoing provision of PFR. The GHD report makes it clear that the proposed framework will not provide an enduring outcome absent an efficient framework for procurement of reserves. We believe this is a major flaw in the proposed framework and risks further changes within a relatively short timeframe, potentially in the form of mandatory headroom requirements or other contractual arrangements with targeted service providers possibly using the system services market. This is further supported by comments by the AEMC in Section 5.2 of the draft determination which suggests the AEMC understands the proposed framework is unlikely to provide an enduring solution.

By continuing to impose mandatory narrow band mandatory PFR on generators without reserves to support its provision, the AEMC's proposed framework effectively reduces the volumes of contingency frequency control ancillary services (FCAS) reserves that may be available to respond as required to a sudden change in frequency due to contingency events. This could have a significant impact on power system security during a major non-credible contingency event. This outcome also creates a compliance uncertainty risk for generating units where it becomes unclear as to when reserves procured for contingency services were 'reallocated' for use by PFR.

In considering the proposed cost recovery and payments framework, the draft rule still does not recognise the full suite of costs that mandatory narrow-band PFR can impose on generators. Reforms to the alignment and length of the sample and application period are positive in some areas but negative in others in that it can result in cost recovery obligations for non-active primary and secondary frequency response being imposed of participants who exhibit good frequency control performance. Our submission sets out alternatives to the proposed framework that we consider delivers a superior outcome to that proposed in the draft determination.

As soon as possible, the Reliability Panel should be tasked with reviewing the FOS, supported by economic and engineering arguments and factors demonstrating the risks the standard seeks to protect the power system from, and the economic costs of doing so should be the target for all frequency control objectives. Following this, the FOS must become the standard to which AEMO should be required to drive FCAS procurement to achieve and only achieve frequency outcomes that meet that standard rather than an artificially excessive standard as could now be argued is the case by observation of the present conditions driven by Mandatory PFR.

Although the draft determination sets out new reporting arrangements for AEMO, we consider that additional monthly and weekly reporting of the level of effective headroom and foot room available for PFR at the time of daily maximum and minimum demand as well as PFR utilised in the system are required.

For further detail on this submission, please contact Ben Pryor (03 9214 9316 or ben.pryor@shellenergy.com.au).

Yours sincerely

[signed]

Libby Hawker
GM Regulatory Affairs & Compliance