The provision of primary frequency control in the Australian National Electricity Market

Regulator response to degradation of frequency performance during normal operation

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***Abstract*— The control of the frequencies of the Australian NEM mainland and Tasmania has been deteriorating in recent times. In particular, the distribution of the frequency within the normal operating frequency band (i.e. in the absence of a contingency such as the trip of generating unit) is significantly flatter than the normal distribution experienced when the NEM started in 1998. This issue was discussed at the 16thWind Integration Workshop in Berlin in 2017 [1].**

Since then, the system operator (AEMO) and the market rule maker (AEMC) have been reviewing the arrangements for managing the frequency within the normal operating frequency band. It has been confirmed that, as discussed at the 16thWind Integration Workshop, one of the drivers of the degradation of frequency during normal operation has been a reduction of primary frequency control provided by synchronous generation within the normal operating frequency band.

Under the current market rules generators are not required to vary their active power output to help correct frequency deviations unless they are enabled to provide a specific Frequency Control Ancillary Service (FCAS). The existing FCAS markets in the NEM do not explicitly include arrangements for the provision of primary frequency control within the normal operating frequency band. Therefore, AEMO and the AEMC are considering new regulatory and market arrangements that will result in the sufficient provision of primary frequency control within the normal operating frequency band.

Keywords- power system operation, frequency control, ancillary services, governor response, policy.

I. INTRODUCTION

The National Electricity Market (NEM) facilitates the transmission of electricity for the 49 GW of installed generation capacity in Australia's eastern states [2]. The Australian Energy Market operator (AEMO) along with the regional transmission companies are responsible for the operation of the power system. The Australian Energy Market Commission (AEMC) sets the rules for the operation of the NEM and the AEMC Reliability Panel, which includes representatives from across the power industry, determines the high level performance standards for power system operation. The Frequency Operating Standard, one such standard, defines the range of allowable frequencies for the power system under different conditions, including during normal operation and following contingency events such as the failure of a major generator or transmission line.

Electricity generation in the NEM is dispatched by AEMO on a five-minute basis to match forecast demand. To manage variations in supply and demand within the five-minute dispatch interval AEMO procures a range of ancillary services to help control frequency during normal operation and following contingency events in accordance with the Frequency operating standard [3]. The current Frequency Operating Standard includes the requirement that, except as the result of a contingency event, the frequency be maintained within the Normal Operating Frequency Band (NOFB), 49.85 Hz – 50.15 Hz for 99% of the time. The current frequency control ancillary services (FCAS) include:

- *Regulating services*, which provide a form of secondary control to help correct slow moving frequency deviations during normal operation, including correcting for forecast error over the 5 minute dispatch interval. These services are activated in response to signals sent to providers by AEMO via its Automatic Generation Control (AGC) system.
- *Fast* (6s), *slow* (60s) and *delayed* (5min) *contingency services* provide a primary control response which automatically respond to frequency deviations outside the NOFB, as measured locally by the service provider. The performance specifications for FCAS are specified by AEMO in the Market ancillary service specification [4].

In addition to procuring FCAS, AEMO co-ordinates the operation of under-frequency load shedding schemes which automatically operate following a contingency event, when the frequency exceeds the operational frequency tolerance band, 49.0 Hz – 51.0 Hz. Figure 1 shows the frequency bands for the mainland NEM along with the operation zones for regulation FCAS, contingency FCAS and under frequency load shedding.

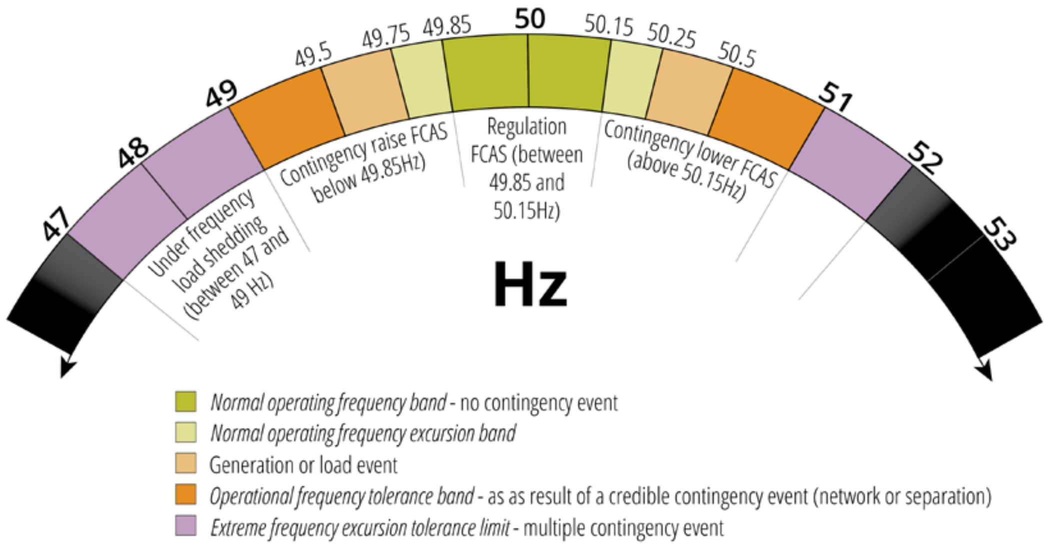

Figure 1. Frequency Bands for the mainland NEM and the zones of operation for ancillary services and under-frequency load shedding schemes

II. Degradation of Frequency Performance in the NEM During Normal Operation

Frequency performance in the NEM during normal operating conditions has degraded in recent times. This degradation was discussed by Summers, Jennings and Peters as part of the 16th International wind integration workshop in 2017 [1]. Figure 2 shows a comparison of the distribution of frequency measurements in the NEM for January 2011 compared with January 2017. This chart shows a flattening and broadening of the frequency distribution, indicating that the power system frequency is spending more time further away from the nominal frequency of 50 Hz.

A. *Impacts of degraded frequency performance during normal operation*

AEMO identified a number of consequences of deteriorating frequency performance, including:

- increased wear and tear on synchronous generation plant due to being moved around by frequency deviations.
- reduction in the efficiency of generators due to changes in output as result of deteriorating frequency regulation and governor response.
- reduction in system security for contingencies that result in significant changes in transfer across interconnectors. The system impact of a sudden loss of generation when the frequency is initially below 50 Hz is likely to be more severe than for a similar event that occurs with the frequency close to 50 Hz. Such an even becomes more likely when the system frequency spends more time away from 50 Hz.
- potential need for additional contingency FCAS to maintain the same standard of system security given increased variability of system frequency.
- possibility of further withdrawal of primary frequency control due to the added burden on existing primary frequency control [5].

B. *Causes of the degradation*

The main cause of the degradation of frequency performance has been identified as the withdrawal of active governor response provided by synchronous generation within the NOFB [5]. This change was implemented by generators through the widening of governor dead-bands and the installation of secondary control systems that act to oppose a mechanical governor response to frequency deviations within the NOFB. The net result of these changes to generator control systems was a reduction in the level of primary frequency control that contributes to maintaining the power system frequency within the NOFB.

The existing market and regulatory arrangements in the NEM do not require or effectively incentivise market participants to provide primary frequency control during normal operation. Therefore AEMO and the AEMC are investigating potential new regulatory arrangements to result in the sufficient provision of primary frequency control within the NOFB [6]. This service is referred to as a primary regulating service.

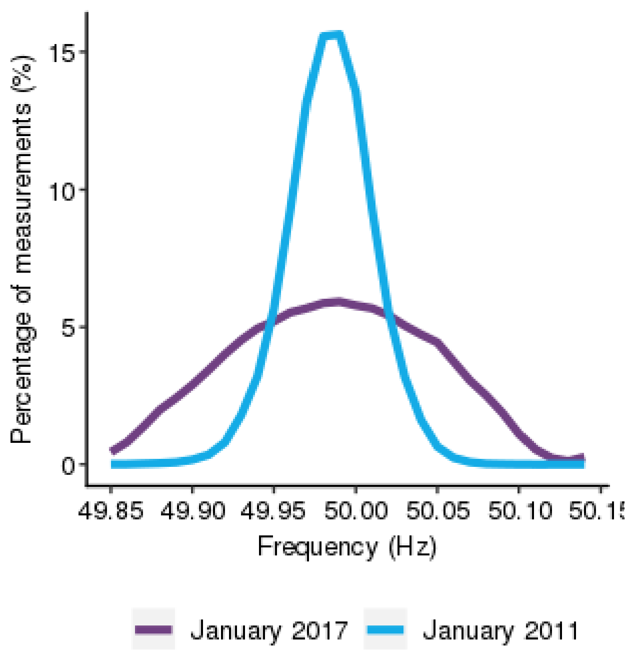

Figure 2. Frequency distributions based on measurement at four second intervals by AEMO for January 2011 and January 2017

III. AEMO'S FREQUENCY TRIALS IN TASMANIA

During May 2018, AEMO ran a series of frequency control trials in Tasmania, in conjunction with the principal generator, Hydro Tasmania, and the operator of the networks, TasNetworks. These trials were undertaken during a period when the HVDC interconnector to mainland Australia was out of service and the Tasmanian power system was operating independently. The Tasmanian system incorporates 3GW of generation of which over 2 GW is hydro power, with the remainder being comprised of wind and gas power generation [2]. Peak demand in Tasmania is close to 1.7GW [7].

The trials involved changes to governor settings on Hydro Tasmania generating units, and to AEMO's AGC system. Outside of these trials generator governor dead-bands in Tasmania are set at ±80 mHz. The effect on frequency control in the Tasmanian power system under normal operating conditions was assessed, as was the effect on the operation of Hydro Tasmania generating units.

A. *Arrangements for frequency control trials in Tasmania*

The trials involved the selective adjustment of several power system control variables for a period of several hours at a time between the hours of 11:00 and 15:00 when the Tasmanian demand is typically fairly stable. The operation of the energy and FCAS markets during the trials was unchanged. The trial periods were excluded from the assessment of generator performance in relation to the allocation of costs for regulating FCAS, known as "causer pays", and generators were assured that generator performance during the trials would not contribute to any compliance investigations.

Over 50% of generating units in Tasmania actively participated in the trials, with most settings modified remotely during operation.

The tests investigated the impact on frequency performance due to the variation of system control settings, including:

- narrowing generator governor dead-bands to zero
- changes to the settings and suspension of AEMO's AGC system

At the end of testing, all governor and AGC settings were restored to their pre-test values.

B. *Results from the Tasmanian frequency control trials*

Figure 3 compares a pre-test baseline period, with a period where the frequency dead-bands of participating generating units were set to zero. Narrowing the dead-bands of these units resulted in the frequency being held far more tightly around 50 Hz than was the case for the baseline period with wider governor dead-band settings.

The trials did not provide a clear indication of the impact of varying the AGC settings or the suspension of AGC for frequency performance. AEMO noted that the test periods were associated with stable system conditions and minimal changes in underlying system load and therefore were not a particularly challenging test of the AGC's frequency management capabilities.

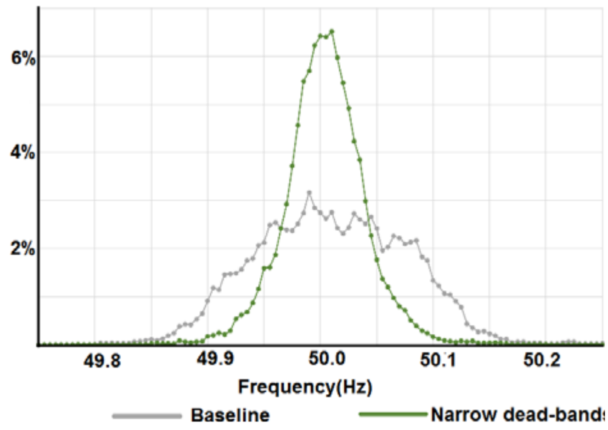

Figure 3. Tasmanian frequency control trial: Frequency distribution from representative baseline period vs period with narrow dead-bands

These tests demonstrated that narrowing the governor frequency dead-bands on selected Hydro Tasmania generating units resulted in a significant and immediate improvement in the control of frequency in Tasmania under normal operating conditions. The role of AEMO's AGC system settings were found to play a less significant role in system frequency performance, particularly under conditions during the testing periods.

Other observations and learnings from the Tasmanian frequency trials included:

- While not a focus of the trials, it was observed that periods of high wind generation resulted in increased variability of frequency
- Narrowing of governor dead-bands resulted in increased governor mileage and generator deviations from dispatch energy targets

AEMO intends to undertake similar frequency control trials in the mainland NEM (Queensland, New South Wales, Victoria, South Australia), to assist in the specification of the quantity and characteristics of primary frequency control required to support adequate frequency performance during normal operation [6].

IV. POTENTIAL POLICY OPTIONS FOR THE PROVISON OF PRIMARY REGULATING SERVICES

The AEMC's final report for the *Frequency control frameworks review* recommended that "market participants should be incentivised to provide a sufficient quantity of primary regulating services to support good frequency performance during normal operation." The AEMC is considering a range of policy options for the delivery of the required primary regulating services.

Broadly, delivery options for these services can be thought of as reflecting greater or lesser reliance on two principal approaches:

1. regulated requirements
2. incentive based provision

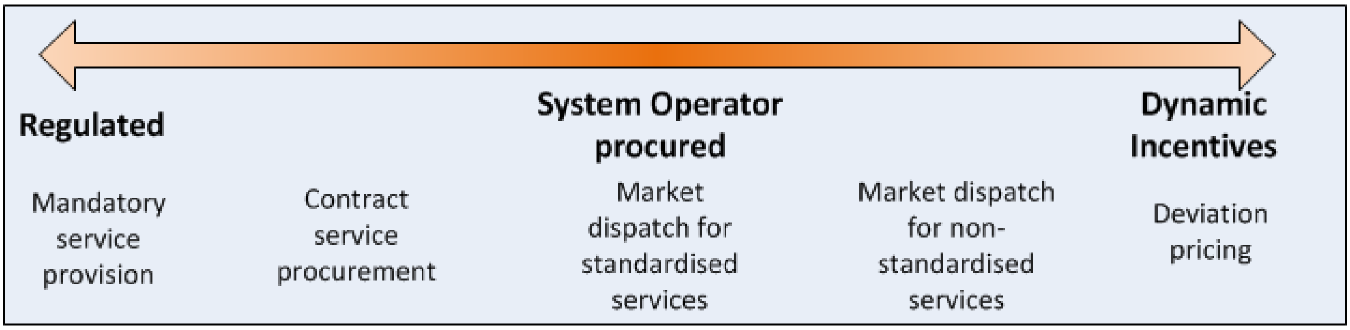

Figure 4. Spectrum of potential policy mechanisms for provision of ancillary services for frequency control

Figure 4 displays a graphical representation of a range of policy approaches across a spectrum anchored at one end by firm regulated approaches and at the other by flexible incentive based measures. Regulated approaches are characterised by increased certainty in relation to how the power system will operate under a range of conditions but decreased flexibility in terms of how individual generators install and operate their equipment. On the other end of the spectrum, dynamic incentive based arrangements are likely to be associated with less certainty in relation to power system operation but increased flexibility in relation to generator technology and operational decisions.

A. Regulated service delivery

At one end of the spectrum, regulatory based approaches involve direct central control over the characteristics and quantity of service provision required to support power system security. Such an approach provides a high degree of certainty that the required services will be active to support power system security. However, this certainty may lead to higher costs from potential over-provision of the system service.

Examples of direct intervention-based mechanisms include minimum technical standards for generators participating in the electricity market.

B. System operator procured

The central region of the spectrum in figure 4 is characterised by the central procurement of the required ancillary services. Under this model the market operator determines the quantity and characteristics of ancillary services required to support power system security. Market participants have the option to supply bids or offers to provide ancillary services in accordance with the specification defined by the market operator. Where there is effective competition, this model encourages market participants to compete with each other to provide innovative and cost effective means of providing the required services.

Two notable examples of system operator procurement for ancillary services are contract procurement and market dispatch.

1) Contract procurement

Under a contract procurement model, providers offer ancillary services on a medium to long term basis in response to a request from the central procurer or market operator. Contracts are awarded for a pre-defined period such as one month through to a number of years. In the NEM, system restart ancillary services are procured via contractual arrangements over a number of years.

2) Market dispatch for standardised services

Alternatively providers could be pre-approved for provision of standardised ancillary services and submit offers for service provision through an automated dispatch process. The existing ancillary service markets for FCAS in the NEM are an example of this form of central procurement for ancillary services. Market participants choose the quantity and price for the provision of FCAS and are enabled based on a system wide auction and dispatch on a five minute basis.

3) Market dispatch of non-standardised (continuous) services

An alternative arrangement that maintains a centralized dispatch for FCAS, and the absence of standardisation of ancillary service characteristics, has been proposed by Wallace, George, Hagaman and Mackenzie as a potential mechanism for the provision of contingency FCAS [8]. Under such an approach, potential providers of FCAS submit offers to AEMO for the provision of FCAS. Offers include the technical capability of the generator to respond to a frequency deviation along with a set of prices for the level and speed of response following a contingency event. This approach allows for the continuous valuation of possible frequency response curves.

Under the continuous FCAS valuation approach, the need for FCAS would be calculated by the system operator for each dispatch interval by taking into account the system conditions, including energy market bids, constraints and operating inertia. Pre-dispatch system modeling would support the co-optimised dispatch of FCAS providers in order to provide the required aggregate system contingency response.

This approach requires an accurate measuring of system conditions and real time system modelling of potential post contingency system states in advance of the market dispatch of energy and FCAS. Such capability is beyond the capacity of the current dispatch engine in the NEM, but may be possible in the future with upgraded operations software such as the Siemens real time pre-dispatch modeling utilised by the Californian Independent System Operator [9].

C. Dynamic incentives

At the other end of the spectrum, a dynamic incentive arrangement provides the maximum technological and operational flexibility for market participants and potential service providers. Under such an arrangement, the quantity and characteristics of the frequency response is not specified in advance through individual control services, but rather is targeted through a pre-defined price function that rewards frequency response in proportion to the extent that it helps maintain the power system frequency close to the nominal 50 Hz.

In order to be effective, the price function must reflect the need for frequency control and either reward or penalise actions that support or impair frequency performance respectively. At the most fundamental level, the need for a frequency control response is proportional to the size of any deviation between the actual frequency at point in time and the target or nominal frequency.

Other benefits of dynamic incentive based arrangements to help manage frequency include:

- they place a financial incentive on market participants to minimise their impact on the need for frequency control services, thereby minimising the quantity of FCAS required to manage system frequency
- they do not require the frequency control services to meet a pre-defined market specification and, as such, are generally technology neutral
- there is flexibility to vary the required frequency response over time to adapt to changing market conditions
- the potential lack of investment certainty may be ameliorated by the ability for market participants to enter into bilateral contracts to hedge their risk exposure to significant deviation charges.

One version approach to implementing a dynamic incentive based arrangement to help manage power system frequency is the 'deviation pricing' approach, described in section V.

V. A DESCRIPTION OF A DEVIATION PRICING MODEL FOR FREQUENCY CONTROL

Under a deviation pricing approach, frequency control is undertaken by participants through a local response to locally measured frequency deviations. Decisions to be frequency responsive are made by each market participant in response to incentives provided through a transparent pricing structure.

The mechanism operates on the basis of a symmetric payment and cost recovery incentive framework. Market participants are paid if their actions assist in moving the system frequency back towards 50 Hz. The cost of these payments is recovered from market participants that contribute to frequency deviations away from 50 Hz. The net result is a balanced two-way system of payments and charges that provides an incentive for market participants to track the trajectory of their generation or load in a manner that supports system frequency.

A key feature of a deviation pricing mechanism is that it allows all frequency control technologies to be appropriately valued in accordance with the speed and profile of their response. The amount that is either paid by or charged to participants is proportional to the value of the response that they provide or the costs that they impose on the system respectively. This mechanism could initially operate as an incentive for a primary regulating response within the normal operating frequency band, but could be extended to value contingency FCAS, Fast Frequency Response and inertia in the future, by extending the price function beyond the bounds of the NOFB.

A key element of a deviation pricing mechanism is the method used to calculate the price that is either paid to participants that support frequency or charged to participants that contribute to frequency deviations.

One option for a method to calculate the price is through the use of a transparent symmetric price function with a rapidly increasing incentive (price) as frequency deviates further from the central target of 50 Hz. This standing price function would use system frequency as the primary variable and would thereby allow for the price to be updated continuously based on changes in system frequency.

An example of such a price function could be based on a linear price increase outside of an initial narrow frequency dead band centered on 50 Hz with the price increasing to (for example) the market price cap at the extremities of the normal operating frequency band as illustrated in Figure 5.[1] This price function could take any form with the illustrated form showing a simple linear relationship that reflects the increasing value of frequency control services as frequency moves further away from 50 Hz. A general form of such a price function would be:

$$\text{Deviation price (\$/MWhr)} \quad \alpha \quad \Delta G(\text{MW}) \times \Delta f(\text{Hz})$$

Once the price function is determined, payments and charges to each participant can then be calculated based on the participant's actions with respect to system frequency. Participants with a generating output that has deviated from their linear dispatch trajectory would either receive or pay the price depending on whether their deviation supported or contributed to the frequency deviation. For example, a generating unit that reduced output below its dispatch trajectory while frequency was above 50 Hz would receive a payment.

The difference in MWs between a participant's output

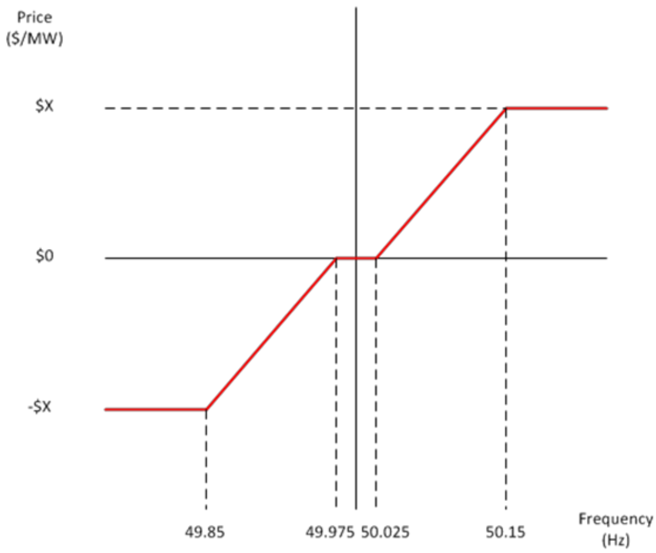

Figure 5. Example deviation price function for frequency control

[1] The narrow frequency dead-band of ± 25mHz is proposed to allow a narrow range within which governor and other proportional responses do not counteract a secondary control signal from the Automatic Generation Control system. For example, this could be to allow for the practice of time error correction.

and its baseline trajectory would be multiplied by the price to determine the overall payment or charge. In this manner, the mechanism would create a financial incentive for participants to limit the extent to which they deviate from the linear trajectory of their dispatch targets, unless to do so supports the frequency of the power system.

The deviation price function would be specified and published in advance. As frequency is readily observable in the power system, and each participant is aware in real time of the extent to which it is deviating from its linear baseline trajectory, this would allow market participants to determine their potential liability under the deviation price function in real time.

With a transparent price function, participants will readily be able to determine the optimal profit maximising settings on their plant. Each participant will be able to calibrate the level of its frequency response based on the costs and capabilities of its respective generating plant. Indeed, some generating plant with more modern control systems may be able to develop control algorithms that optimise plant settings consistent with the pre-defined price function.

As each participant will be able to optimise their control settings, this will mean that those generators that are able to provide a frequency response at a lower cost will set their dead bands at a narrower range and will therefore be the first to respond to any deviations in frequency. Increasingly higher cost participants will set their dead bands at wider ranges so as to only provide a frequency response in the event that frequency deviations are larger and the payments or charges are higher.

Furthermore, the introduction of a dynamic performance-based mechanism would likely assist more unconventional frequency response technology developers to find a market for their products. Such a model is therefore likely to effectively encourage helpful frequency response from generation plant and potentially responsive load, regardless of the plant technology. In this manner, a deviation price function is able to provide a long term arrangement to support the provision of frequency control.

VI. Conclusion

In the final report of its *Frequency Control Framework Review*, the AEMC considered that the efficient and effective achievement of good frequency control is most likely to occur in circumstances where participants are rewarded or penalised consistent with the value of their actions on system frequency. In other words, costs are imposed on those participants that cause frequency deviations and payments are made to those participants that minimise frequency deviations. This could be achieved through an efficient and effective policy mechanism that satisfies the following criteria:

- *Performance-based and dynamic* - Payments made to participants to support frequency, and charges to participants that contribute to frequency deviations, must be consistent with their actions and the value these actions provide to the system.
- *Transparent* – Participants must be provided with the means of understanding how their actions relate to the costs or rewards they are likely to incur[6].

In response to the confirmed degradation of frequency performance in the NEM during normal operation AEMO and the AEMC are in the process of defining the characteristics and mechanism for the provision of a new ancillary service, a primary regulating service. The AEMC has considered a range of potential policy mechanisms across a spectrum of approaches from regulated mechanisms through central procurement and out to dynamic incentive based pricing mechanisms. In its final report it concluded that a dynamic, transparent and performance based mechanism is likely to promote effective frequency control over the coming decades as the NEM transitions towards more asynchronous generation and less synchronous generation. Such a mechanism is also likely to promote efficient investment in and operation of power system equipment both in the form of generation plant and responsive loads.

The AEMC has described a deviation pricing mechanism that would provide dynamic performance based incentives to guide the operational behavior of market participants which would then incentivise primary regulating services

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