A DOUBLE-SIDED CAUSER PAYS IMPLEMENTATION OF FREQUENCY DEVIATION PRICING

A Project Sponsored by the Australian Energy Council

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ANALYSIS REPORT

IES
Intelligent Energy Systems

Disclaimer

The views expressed herein are not necessarily the views of the Australian Government. The Australian Government does not accept responsibility for any information or advice contained within this document.

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Executive Summary

The Australian Energy Council (AEC) with ARENA support has sponsored this project to examine a specific option for pricing and promoting a market for Primary Frequency Response (PFR) in the National Electricity Market (NEM). PFR is a service required to keep system frequency within an acceptable limit (as defined by the Reliability Panel) under normal operating conditions. The work is motivated by a desire to see a market for PFR maintain good frequency control in normal conditions in the NEM when the current mandatory approach to provision was expected to sunset in 2023.

This report aims to examine quantitatively some key issues identified in the Inception Report. It also presents and gives examples of a calculation methodology for a version of Double-Sided Causer Pays (DSCP), a special implementation of Frequency Deviation Pricing (FDP). The Final Report for the project will attempt to specify and justify particular design and parameter choices.

In this report we:

- analyse recent frequency control performance in the NEM and the scope for improvement;
- analyse the potential sources of metering error if SCADA metering is used; and
- set out one variation of the pricing and settlement logic proposed for DSCP, with an example based on real historical 4 second data.

We also have under development a more detailed technical model to illustrate the workings of FDP/DSCP under various design choices and under different scenarios, such as a renewable dominated scenario expected in, say, 10 years hence. However, we have chosen to focus in this report on developing tools to analyse historical data. We will further develop our forward-looking technical model for later use in consultations on the project and after.

Our main conclusions for the analysis in this report are:

- The Mandatory Primary Frequency Response (PFR) rule introduced by the AEMC, National Electricity Amendment (Mandatory primary frequency response) Rule 2020 No. 5 and implemented by AEMO with effect from 4 June 2020 has been successful in improving system frequency performance. However, this has been achieved substantially from plant that is expected to be phased out over the next decade or two. There remains the challenge of how to muster resources efficiently to achieve adequate frequency performance.
- SCADA metering is subject to a range of error sources, more so than dedicated revenue metering. The likely largest source of error is the potential delay between measurement at a site and its receipt by AEMO. Some DSCP measures, including raw frequency, are more sensitive to delays than is a lagged measure such as the FI from the AGC system or a smoothed frequency measure. For compliant units with data delays less than 6 seconds, the error is mostly bounded but there are likely to be pathological cases. A program to develop and roll out dedicated DSCP meters would certainly resolve this issue but should not be required for an initial implementation.

The possible need for upgrade of some communication facilities and the associated cost needs consideration at the design stage.

- This analysis also highlighted some likely design choices related to metering, including:
  - Units with missing or poor-quality data should be treated as part of the residual for affected dispatch intervals;
  - The FDP/DSCP system should continue to operate during a contingency event.
- We have developed code which can process SCADA data for notional DSCP settlement using various design parameters. This will be used to further tune and stress test our final recommendations, along with the operational modelling foreshadowed in our Inception Report.

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1 Introduction

1.1 Project and Report Objective

The Australian Energy Council (AEC) with ARENA support has sponsored this project to examine a specific option for pricing and promoting a market for Primary Frequency Response (PFR) in the NEM. PFR is a service required to keep system frequency within an acceptable limit (as defined by the Reliability Panel) under normal operating conditions. The work is motivated by a desire to see a market for PFR maintain good frequency control in normal conditions in the NEM when the current mandatory approach to provision was expected to sunset in June 2023.

In its Frequency Control Arrangements Review and subsequent discussion papers, AEMC has identified some modification or of the existing causer pays system for regulation as a candidate for pricing PFR[1]. Subsequently, CS Energy commissioned a small project of IES to demonstrate how such an approach might work; the approach was called Double-Sided Causer Pays.[2]

The aim of the current project is to outline the basis for Frequency Deviation Pricing (FDP) specifically applied to PFR but also recognising its applicability to a closely related but lagged, secondary service. DSCP is a specific implementation of FDP applied to PFR but potentially also covers AGC regulation or a similar decentralised service as well as other possible faster or slower acting services. AEC sponsorship does not imply a commitment to the approach by itself or by its members; only a desire to see the option fully examined.

The project is carried out in four stages and two, intermediate and final, knowledge sharing workshops. [3] The current document reports on the third stage, which aims to examine quantitatively some key issues identified in the Inception Report. Readers are strongly advised to review the Inception Report[4] and Pricing and Theory Report[5] before tackling the current report.

In the weeks before this report was finalised but when drafting was substantially complete, the AEMC published its draft determination on enduring arrangement for PFR[6]. The approach taken in the draft determination should be considered. However, we have chosen to make these adjustments, if any, in our final report. The procedure outlined in this report can be adapted readily to a range of different design options.

1.2 Double Sided Causer Pays as an Implementation of FDP for PFR

For this work we will take DSCP to be pricing system for PFR and potentially also related services that would operate broadly as follows:

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[1] AEMC, *Frequency control frameworks review, Final Report*, 26 July 2018
[2] IES report for CS Energy, *Double-Sided Causer Pays for Primary Frequency Control – Final Report*, 19 March 2
[3] The four stages are documented in four reports: Inception Report, Theory Report, Analysis Report and Final Report.
[4] IES, *A Double-Sided Causer Pays Implementation of Frequency Deviation Pricing- Inception Report*, 16 April 2020

[5] IES, *A Double-Sided Causer Pays Implementation of Frequency Deviation Pricing- Control and Pricing and Theory Report*, 14 July 2021
[6] AEMC, *Primary frequency response incentive arrangements, Draft rule determination*, 16 September 2021

- Similar to causer pays for regulation, the measure of participant performance is the correlation between frequency deviation and generation/load deviation. Because the expected value of these deviations should all be zero, we can take correlation to be proportional to the product of frequency deviation and unit deviation averaged over a settlement period, possibly weighted differently in each 5-minute dispatch interval (DI). The Pricing and Theory Report outlined the control theory basis for such an approach and identified its key elements. Consultations with the industry have helped to refine those elements.
- Unit deviation is defined as the difference between measured power and a reference power trajectory, defined as a linear ramp between scheduled dispatch targets at 5-minute boundaries. Other reference trajectories are possible. Frequency deviation is defined as the difference between measured frequency and the reference frequency which is 50 Hz in Australia although a small frequency bias may at times by justified to correct time error.
- As with regulation causer pays, we use 4-second SCADA data to make these measurements and to financially settle the payments. However, participants can also make these measurements locally as the PFR prices will be defined as a simple function of frequency. Higher resolution, higher accuracy metering is also possible and implementation should recognise that different grades of metering will be in use.
- For practical implementation, factors are accumulated into 5-minute values and these in turn accumulated over a billing period. Sites not 4-second metered (mostly customer loads) would be treated as residuals.
- Unlike regulation causer pays, settlement would be based on performance at the time of measurement.
- The system may distinguish raise and lower services operating at different pricing levels, although this may not be necessary.
- The CS Energy/IES work used a specific approach to determine the pricing weight to be given to the measured factors. This approach was intended as illustrative only and subject to further investigation. In this report we recommend a different approach.

1.3 Outline of this Report

This report generally follows the proposed content for the Analysis Report outlined in the project Inception Report, with some exceptions. First, an operational model of DSCP applied to a representative electricity system is still under development but is not yet adequate to undertake some of the specific studies we foreshadowed in the Inception Report, such as likely behaviour as batteries penetrate further into the market and coal plant retires. This work will be reported on separately later in the project.

Next, we have taken the opportunity to apply the proposed DSCP logic to historical frequency and plant performance data to help understand the nature of financial outcomes under DSCP. We present an illustrative example in this report but the software we have developed can also be used to test variations in implementation.

The remainder of this report is structured as follows:

INTRODUCTION

Section 2 Analyses recent frequency control performance in the NEM and the scope for improvement;

Section 3 analyses the potential sources of metering error if SCADA metering is used;

Section 4 notes the control and pricing model and back-casting procedure that have been developed to support the project. These are described in Appendices A and B; and

Section 5 Summarises the conclusions of the Report and sets out the next steps proposed in the project.

2 Recent Performance and Scope for Improvement

2.1 Introduction

With the commencement of the mandatory PFR rule change, there is a very significant improvement to the control of frequency within the Normal Operating Frequency Band (NOFB). As the current rule sunsets in 2023 and a market/incentive mechanism proposed by the AEMC to replace it, in this Section we detail the improved performance of the units as a result of mandatory provision with the goal of identifying any scope for further improvement. The relative performance of units under AGC is also reviewed.

2.2 Recent System Frequency Trends

Figure 1 displays the standard deviation of frequency for each 2-month period from Jan-2020 till Jun-2021 (1.5 years) for both Mainland and Tasmania areas. This shows that frequency is greatly improved after Oct 2020 but has not improved significantly beyond that. Table 1 shows AEMO's schedule for implementing the mandatory PFR requirements on different tranches of power stations. The performance chart and the schedule indicate that most of the benefit is provided by the units in tranche 1. The performance of each unit is analysed and reported in the following sections.

Figure 1 Bimonthly standard deviation of frequency

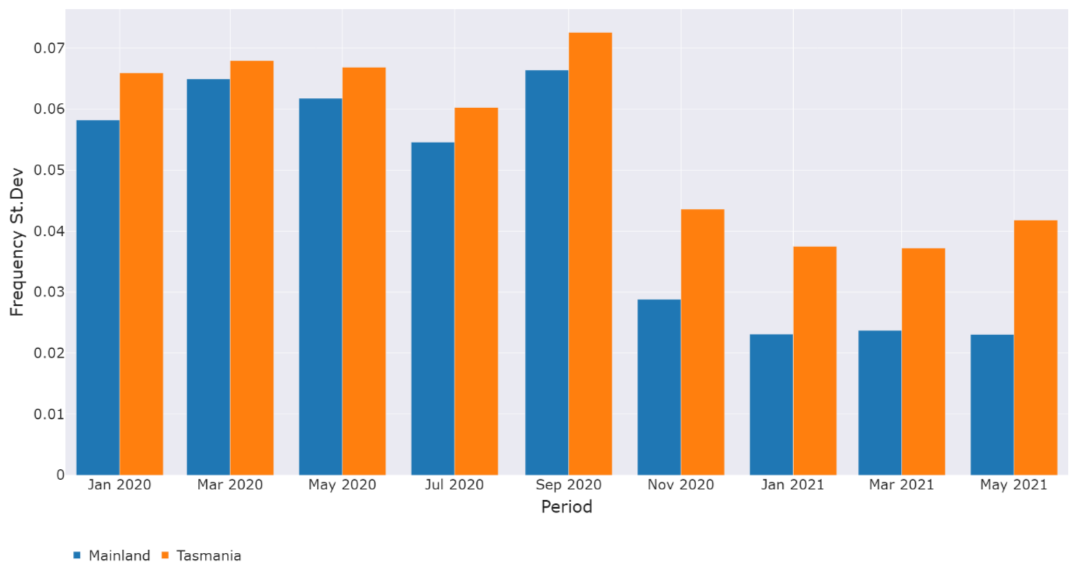


Table 1 AEMO PFR Implementation Schedule (Source: AEMO PFR Implementation update[7])

Tranche	Membership	Capacity (approx.)	Stations	Target for Implementation	Completed (as of Jul-2021)
1	DUIDs > 200MW	35.6GW	44	Pre summer 20/21	Approx. 30.2 GW (85 %)
2	DUIDs 80-200MW	17.4GW	101	30 Mar 2021	Approx. 6.4 GW (37 %)
3	DUIDs < 80MW	5.1GW	88	30 June 2021	Approx. 1.8 GW (36 %)
Total		58.1GW	233		Approx. 38.4 GW (66 %)

2.3 Methodology for Performance Analysis

2.3.1 Calculation of performance measures

- Study period: Access frequency measurements for both Mainland and Tasmania regions, Dispatch targets, measured generation and nominal capacity for all units from Jan-2020 till Jun-2020.
- Calculate and store the performance metrics for each area. In this work, two performance metrics are considered (see Figure 3 Bimonthly performance measures for Kogan creek power station
-
    - **4sec_freq**: negative of frequency – This represents a fast (within 4 seconds) response of the system, classed as primary frequency control.
    - **35sec_freq**: filtered or smoothed version of above with a time constant of 35sec – This represents the lagged (or integral) response that could be expected currently for a unit on secondary frequency response duty under AGC.

As presented in our Theory Report each of these can be represented by a metric *f(x, tc),* a smoothing function of the measured variable x (negative frequency in this case) with time constant *tc*, where *f(x, tc)* is calculated recursively from successive frequency (Hz) measurements as follows.

$$f(x, tc) = (1 - dt/tc)*previous\ f(x, tc) + (dt/tc)*x$$

where

dt is the measurement interval

x is the negative of the frequency measurement in Hz

[7] https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2021/pfr-implementation-report-v17-23-july-21.pdf?la=en
https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2020/pfr-implementation-update.pdf?la=en

When the measurement interval *'dt'* is 4 seconds (mainland SCADA) and *'tc'* is also 4 seconds, this formula yields the raw measurement (negative of frequency measurement). If *'dt'* is much smaller, say 0.1 seconds and *'tc'* is 4 seconds, we get a filtered metric that will approximate a raw 4 second measurement but which can be regarded as more accurate or discriminating.

- Calculate and store deviations for each station as the difference between measured output and the linear ramp trajectory defined by successive dispatch targets.
- For each station and 2-month period: calculate and store the Pearson correlation coefficient of the station's deviation and the specified performance metric.
  - The Pearson correlation coefficient is a normalised measure (between -1 and 1) of the covariance between two variables, the two-time series under analysis. The Pearson correlation coefficient measures only the strength of linear association. For example, a correlation of 1 indicates that the series are perfectly positively correlated, it does not indicate that the series have the same magnitudes but that the series changes in value with the same sign (direction) and the same proportions.

The above method yields a correlation measure for every station, performance-metric and 2-month period combination. The two chosen performance metrics and raw frequency data are plotted for Kogan Creek power station over a 30 -minute period are plotted in **Error! Reference source not found.** A plot of the bimonthly performance measures combined with equal weighting for the station over the period under investigation is displayed in Figure 3.

Figure 2 Frequency and Performance Metrics for Kogan Creek Power Station

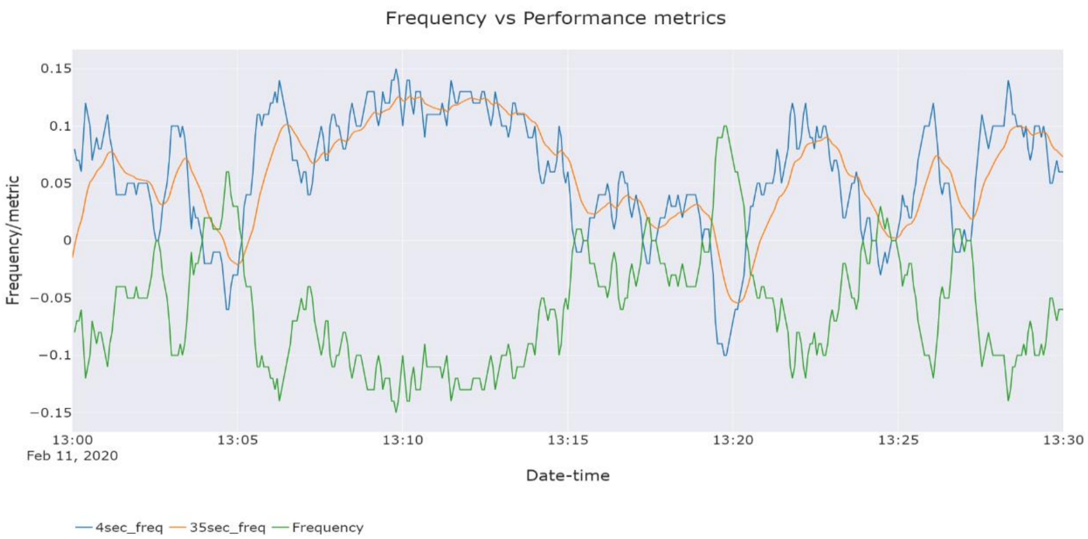
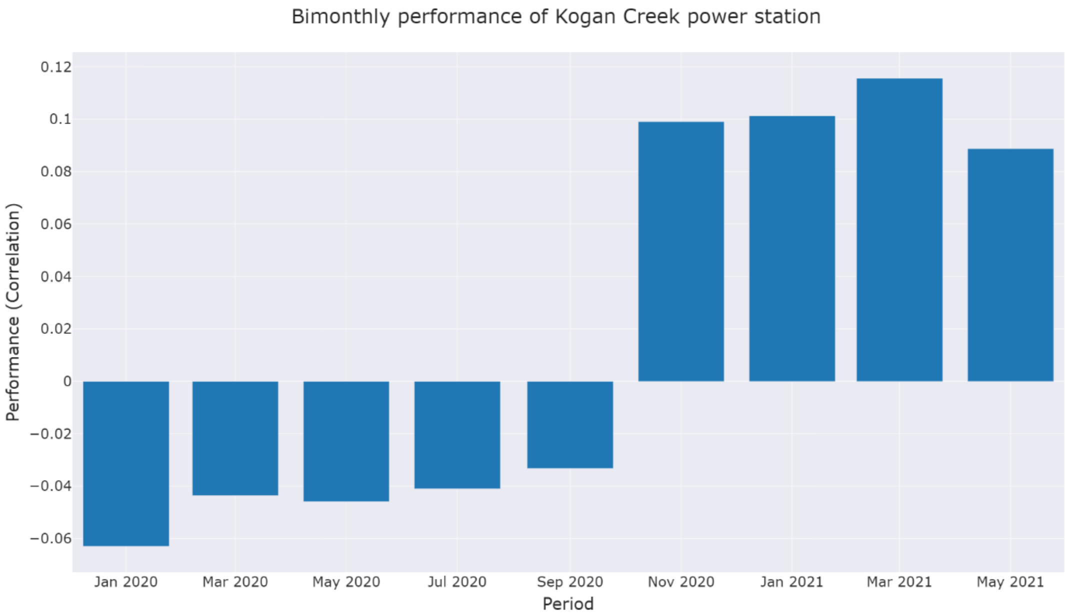


Figure 3 Bimonthly performance measures for Kogan creek power station



2.3.2 Charting performance against cumulative capacity

It is instructive to plot the performance of all stations against cumulative nominal capacity by applying the following procedure:

- For each 2-month period access the performance measures and nominal capacity for each station under investigation
- Sort the data in descending order of performance measure
- Calculate the cumulative sum of the nominal capacity
- Plot station performance measure against the cumulative sum of nominal capacity.

The above method is used to create the charts displayed in the following sections.

2.4 Performance of all units

In this section, two performance charts are displayed for all stations. Figure 4 is a chart showing performance relative to the 4 second (SCADA) metric. Figure 5 is a chart showing performance relative to the 35 second lagged metric. The charts show the performance of each station against cumulative capacity for each 2-month period from Jan 2020 to Jun 2021.

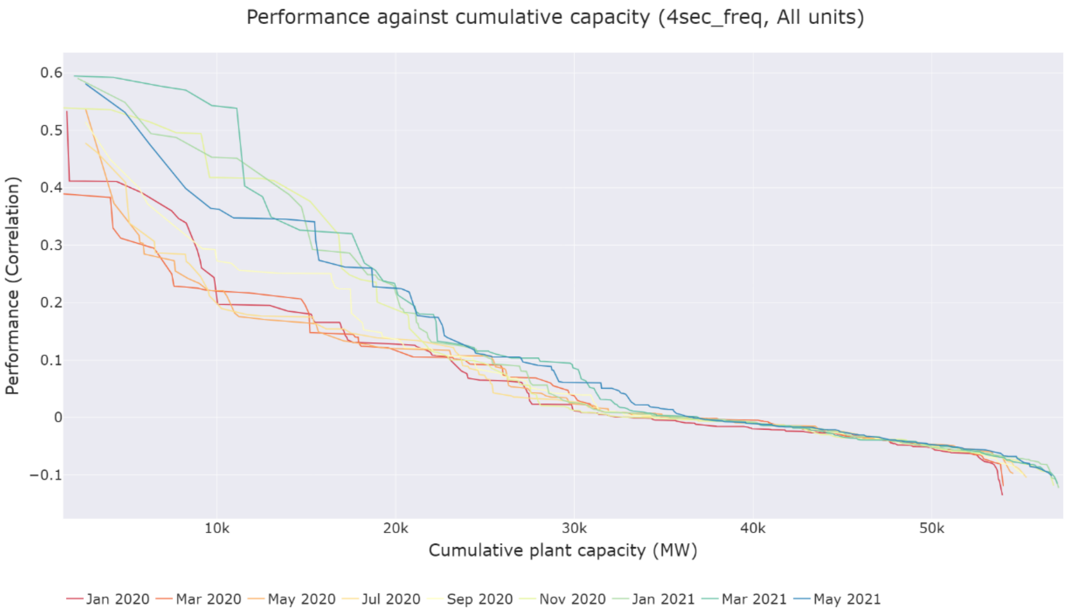
The traces in the chart show an improvement in individual performance as the MPFR dead bands are implemented. This is indicated by higher traces in 2021 compared to 2020. The traces also show that approximately 20GW of generation (after approximately 30 GW on the horizontal axis in the charts) do not show any improvement. The lack of improvement is indicated by no change in performance, nearly overlapping lines, from month to month. This can be attributed to:

- Not all units have been updated with the new dead band settings. AEMO has reported that many inverter-based generators require updated firmware from the OEM which has delayed implementation. According to AEMO's latest update[8], this would only include approximately 13GW of generation though.

- The remaining units have not allocated sufficient spare capacity (headroom or foot room) to modulate output to provide PFR.

The charts also show that not all units are equal in their response even when they have improved. Some units show a great positive correlation to the performance metrics while other show a smaller correlation and some show negative correlation (but these could be due to the delay in dead band implementation).

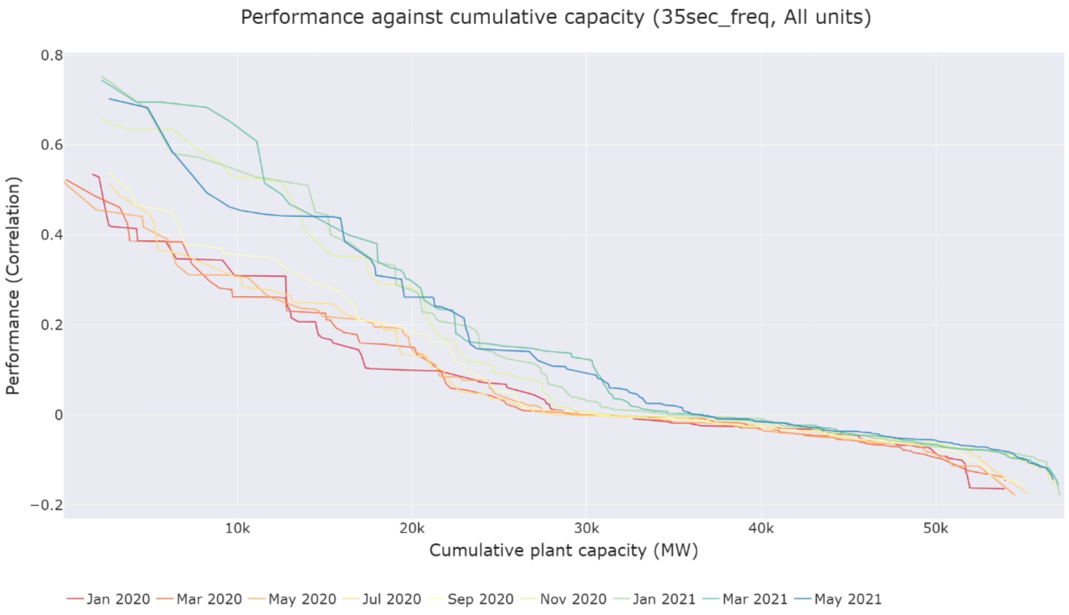
Figure 4 Performance of all units using the 4sec_freq performance metric against cumulative capacity



Noteworthy also is that the 35 second lagged response has improved along with 4 second (PFR) response resulting from the PFR mandate. Interestingly the improvement is greater for the 35 second measure than for the 4 second measure, even though the rule change targeted the 4 second (PFR) metric. This cannot be surprising as **Error! Reference source not found.** shows a high degree of correlation between the 4 second and 35 second measures.

[8] https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2021/pfr-implementation-report-v17-23-july-21.pdf?la=en

Figure 5 Performance of all units using the 35sec_freq performance metric against cumulative capacity



2.5 Performance of units providing AGC regulation

In this section, the performance charts are displayed for all stations that provide AGC regulation. Figure 6 following is a chart showing performance relative to the 4 second metric and Figure 7 is a chart showing performance relative to the 35 second metric. The charts show the performance of each station against cumulative capacity for each 2-month period in the study period. Note that the analysis did not separate periods when the unit was not enabled, it shows the correlation of a unit for the entire 2-month period if it had been enabled at least once, this approximation was made because units enabled for regulation will generally be enabled for a long period. This approximation has the benefit of capturing all flexible plant capable of providing AGC regardless of whether or not it actually did.

The charts show that there was significant improvement as the MPFR requirements were implemented. This improvement covered about two thirds of the enabled units for the 4-second measure and nearly all units for the 35 second measure.

The last observation is at first sight surprising for units that are already enabled for AGC regulation. However, given the correlation between 4 second and 35 second metrics shown in Figure 2, it is evident that a fast PFR response to a deviation is, more often than not, likely to be consistent with closely following an AGC trajectory. The improvement could also be related to the changes AEMO made to the AGC after the changes to generator dead bands were implemented (as part of the MPFR rule change) to make better use of regulation reserves. The changes commenced on 9 Dec 2020 and included dead band and gain adjustments and changes to make the integral response more persistent[9].

Figure 6 Performance of AGC-Regulation enabled units using the 4sec_freq performance metric against cumulative capacity

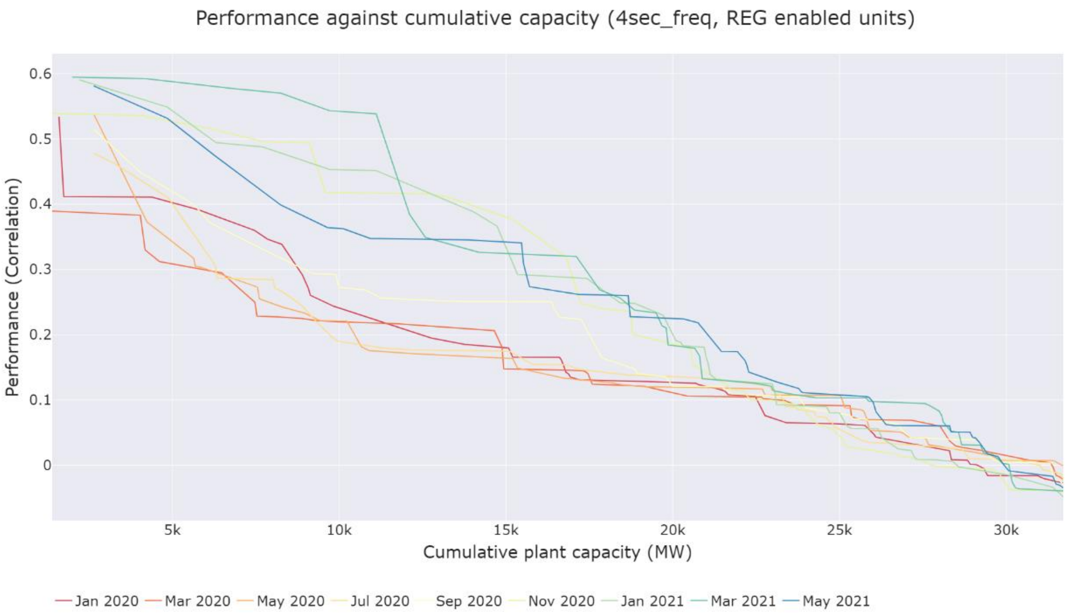
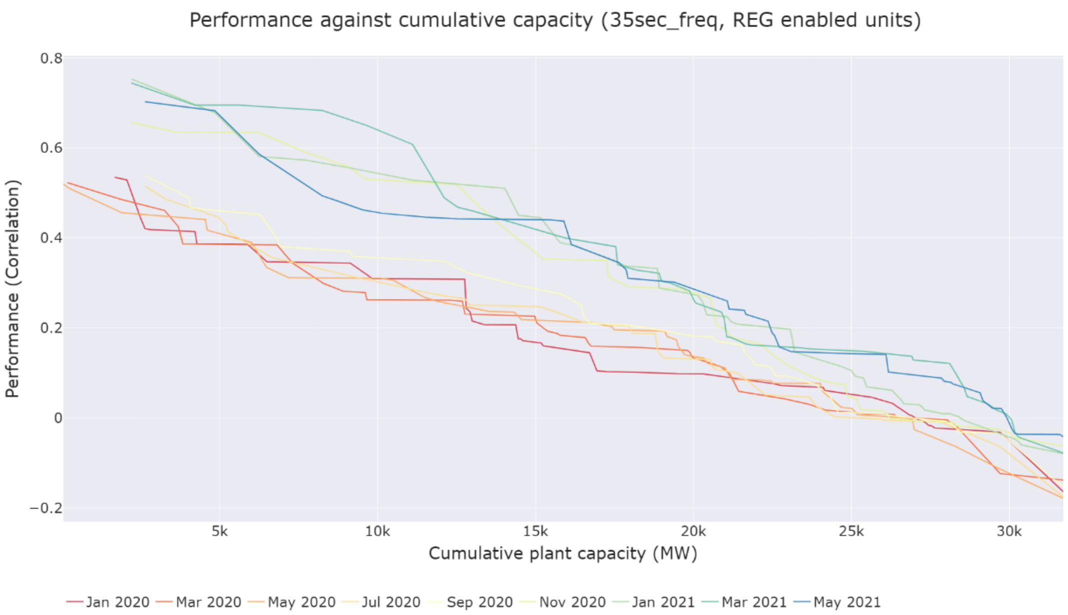


Figure 7 Performance of AGC-Regulation enabled units using the 35sec_freq performance metric against cumulative capacity



[9] See Section 5.6 of https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2021/pfr-implementation-report-v17-23-july-21.pdf?la=en

2.6 Performance of units not providing AGC regulation

In this section performance charts are displayed for all stations that do not provide AGC regulation. Units not yet updated with the new MPFR requirements will typically belong to this group. The charts following show the performance of stations not enabled for AGC regulation in the same way as the charts in section 2.5.

As would be expected, the performance of these units is generally worse than that of AGC-enabled units because relatively inflexible plant would fall into this category. However, as the MPFR implementation has progressed some units, representing around 20% of the capacity of this group, show much improvement but not as much as the AGC enabled units. Notwithstanding these exceptions, around 20 GW of plant in this category have made no improvement in their performance. This exceeds the Tranche 2 and Tranche 3 combined capacities in AEMO's MPFR implementation schedule shown in Table 1.

Figure 8 Performance of non AGC-Regulation enabled units using the 4sec_freq performance metric against cumulative capacity

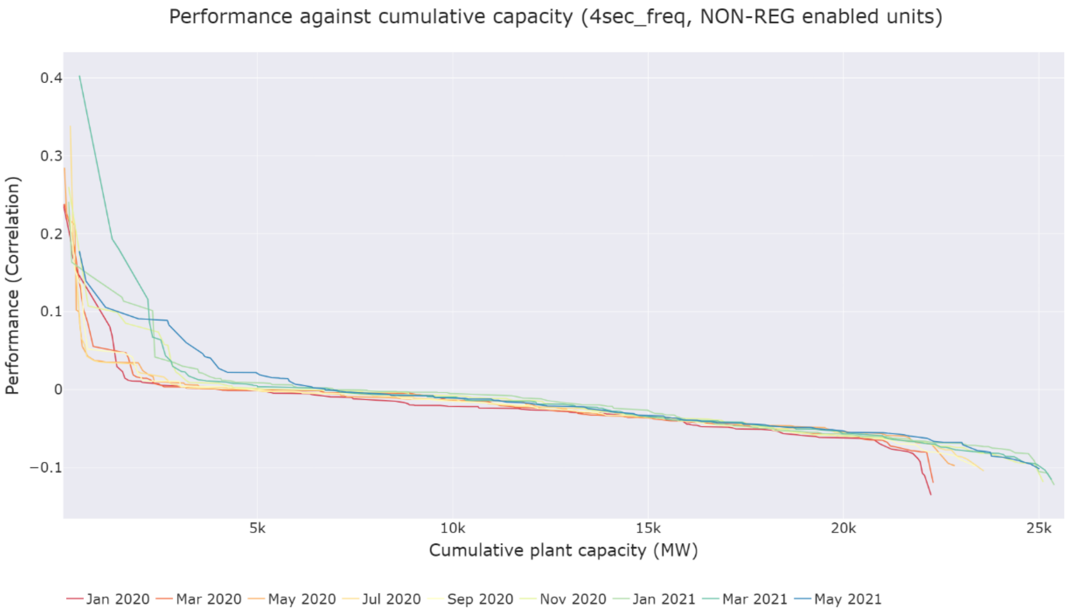
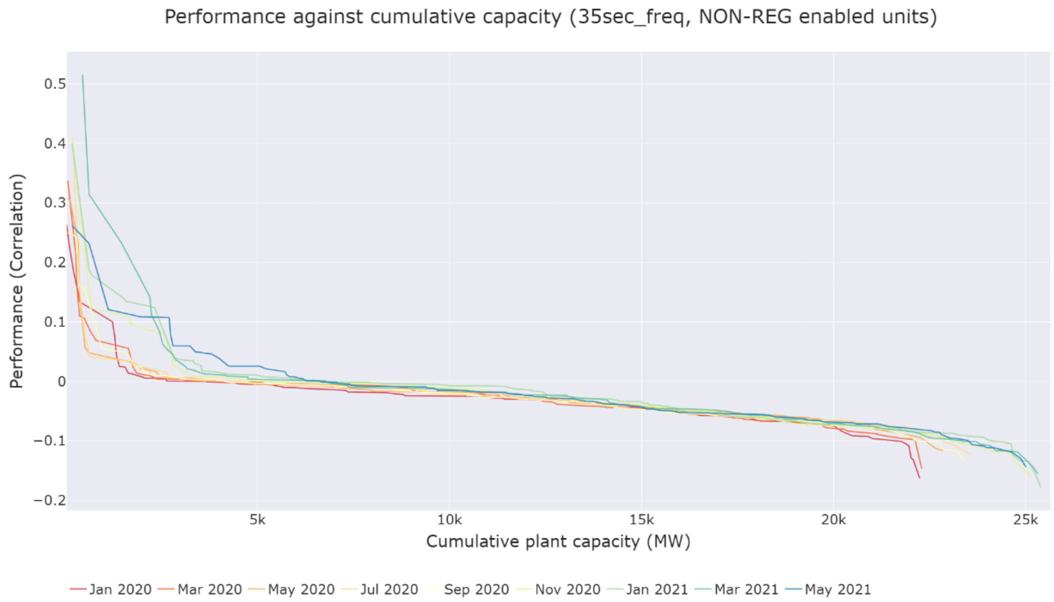


Figure 9 Performance of non AGC-Regulation enabled units using the 35sec_freq performance metric against cumulative capacity



2.7 Scope for Improvement

The range of performance across stations is quite varied. Most of the good frequency control performance is being provided by large thermal units with the order of half of the existing generation fleet (measured by MW rating) providing very little at the time of analysis. Many or most of the low performing units will depend on renewable energy inputs with large opportunity costs associated with maintaining headroom as well as upgrading their inverter control systems. As large thermal units exit the market, other units will need to improve their frequency control performance to satisfy the security requirements of the NEM.

The mandatory rule has succeeded in re-instating a high level of frequency performance in the NEM. The benefits of moving to a market-based arrangement are therefore not in improving frequency performance, at least in the short term. The issue in the near term is whether this result can be achieved more efficiently and perhaps consistently. In the longer term, as large thermal units withdraw from the market, as the power output from the generation fleet becomes more variable and as system inertia declines, the question of how to maintain good frequency control performance is likely to re-emerge.

In the longer term a rule mandating a frequency control capability across all units is likely to be costly. For example, if renewable plants together had to maintain, say, 100MW of headroom at all times, with an average energy cost of $50/MWh the annual cost would be around $44 million. If such plants were not compensated for being required to maintain headroom but required to maintain the capability, the cost of investing in and maintaining that capability would be borne by that plant. Further, a mandated capability is less likely to be appropriately designed and implemented than one driven by market incentives.

RECENT PERFORMANCE AND SCOPE FOR IMPROVEMENT

AEMO has received advice from an international expert that PFR capability should be spread as widely as possible, ideally to all generation, to ensure maximum diversity and security of supply and a corresponding minimal performance requirement on each unit. In this way AEMO argues that the cost of provision will be minimal (for an individual unit). However, to the extent that backing off to maintain headroom is required, spreading the burden around makes no or little difference to the $44 million per 100MW per year indicative cost to the renewable fleet.

In any case, a robust diversity of supply can be achieved without mandating near universal supply. Most renewable installations are relatively small compared with thermal power stations. Suppose we have 5 regions with 10 renewable plants and 10 batteries in each region, all of equal and ample frequency control capability provided the renewable plant is backed off. The system would surely remain robust if the frequency control duties were confined to the batteries for 95% of the time. Five big batteries in each region should be ample to maintain frequency in the event of separation. Only if the number of supply units in a region should fall to one or zero should the robustness issue arise.

With battery sizes increasing, it is possible that a battery owner might seek to dominate regional supply of frequency services under a market arrangement. For this reason, some hopefully light-handed rule could be implemented to limit such domination. Such a rule could be, for example, set a lower limit on droop settings (i.e.an upper limit on MW/Hz) for the unitor an upper limit on the MW that would be paid.

3 Impact on DSCP of Potential Metering Errors

3.1 Introduction

SCADA metering is designed to monitor many key aspects of the electricity system including unit generation. Since the early days of the NEM it has also been used to measure conformance to dispatch trajectory and, through this, the allocation of the cost of AGC regulation enablement under the so-called Causer Pays procedure. While the resolution, accuracy and reliability of SCADA metering is not ideal for this purpose, with some adjustment it has been proven to be adequate until relatively recently, when the omission of PFR from the procedure has been a factor in the decline of frequency control performance. The aim of DSCP is to correct this omission.

Low resolution SCADA metering generally allocates the costs of regulation satisfactorily. This is because frequency measured at 4 seconds filtered with a time constant of about 35 seconds through the AGC is slow moving signal generally impervious to delays in transmission of a few seconds or even as high as 10 seconds. However, its capability to measure PFR under a DSCP arrangement may be more problematic as the signal would be unfiltered or fast-filtered. For this reason we review in this Section the scope for various types of metering errors when SCADA is applied to PFR-DSCP as well as a regulation service. Specifically, we cover the following types of error, as outlined in the project Inception Report, with the addition of time resolution error:

- Scaling error
- Offset error
- Time delay error
- Discretisation error
- Random error
- Outage error
- Time resolution error

From this analysis we draw some conclusions on SCADA metering and then proceed to consider the following:

- Other metering options
- Standard fast metering
- Fast metering dedicated to Frequency Deviation Pricing (FDP) service

3.2 SCADA metering

3.2.1 Scaling error

Scaling error arises in SCADA systems when the physical quantity (e.g. generation) is presented as a quantity directly proportional to the actual value. This is largely corrected at the commissioning stage by a fixed scaling parameter. AEMO has strict procedures [10] for controlling such errors and hence this is largely mitigated.

[10] See SCADA end-to-end testing from https://www.aemo.com.au/-/media/Files/Electricity/NEM/Network_Connections/Transmission-and-Distribution/Connection-and-Registration-Requirements.pdf

3.2.2 Offset error

Offset errors arise when the physical and measured quantities display a constant offset i.e. there is an error independent of the size of the measurement. It is typically rolled into an overall error at some meter rating and so not easily separated from other error sources such as scaling error.

Offset errors cancel in practical application for system control as well as Causer Pays and potentially, DSCP and FDP. For example, to estimate power deviations, we take a set of SCADA-measurements and subtract its straight-line dispatch trajectory. However, the trajectory is itself initialised at a SCADA reading which delivers a target SCADA measurement at its end. This differencing process of two SCADA readings or estimates eliminates the offset error but not any scaling error.

3.2.3 Time delay error

Delays in the data transmission from a site to AEMO premises cannot be removed completely. AEMO's data communication standard [11] allows for up to 6sec of delay for data relating to dispatch. The sensitivities of the DSCP transaction calculations to any transmission delays were investigated. The approach and results are discussed below.

To identify the sensitivity of DSCP transaction to delays, artificial shifts were applied to the raw data (7-day period starting on 1 Feb 2020) before computing the DSCP factors. Five different shifts were considered: +8, +4, -4, -8, -12 seconds; multiples of 4 are chosen as the resolution of the data is 4 seconds on the mainland. The negative shifts represent a situation where the SCADA MW generation data as recorded at AEMO are delayed further relative to the system frequency data. The MW generation data obtained from AEMO already has delays present (although AEMO measures frequency at its own site), in which case a positive shift represents a move in a direction that corrects for the delay.

Three different performance metrics were used to calculate the factors under each delay:

- 4sec_freq performance metric (PFR-DSCP)
- 35sec_freq performance metric (Secondary-DSCP)
- FI (Causer Pays Procedure). This is included to provide an estimate representative of current Causer Pays calculations and their sensitivities to delays[12].

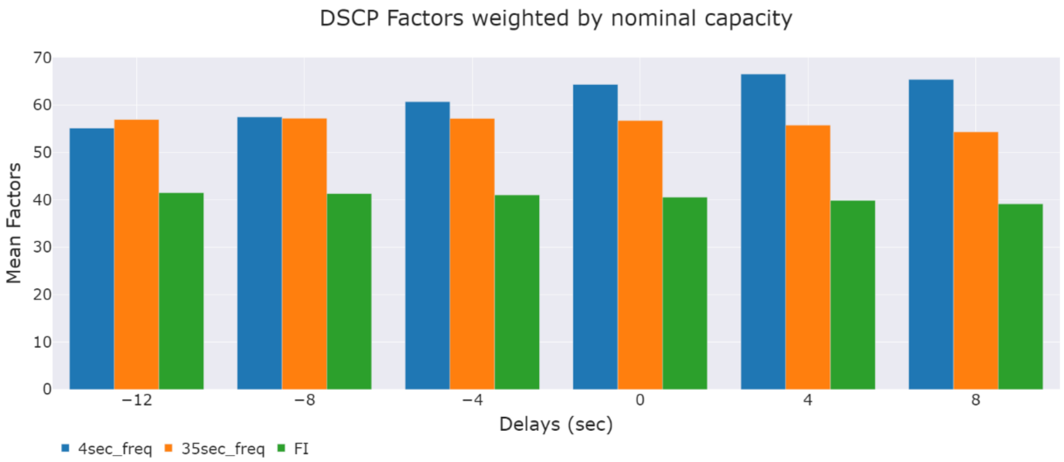
Average Analysis

Figure 10 displays the average DSCP factors for all units normalised by plant capacity. The factors calculated using the lagged and FI metrics (orange and green bars respectively) are relatively stable while the instantaneous (4 second PFR) factors (blue bars) show more variation with delays. This is to be expected as lagged and FI metrics vary slowly while the instantaneous metric (the blue bars) varies more quickly and so is more sensitive to delays. Noteworthy is that the PFR metric peaks at a correction of positive 4 seconds, which is within the 6 second delay allowed within AEMO's SCADA standard. Because the factors peak in the direction of appropriate corrections, the errors for plant conforming to SCADA metering standards remain at less than around 5%. Importantly, there is an

[11] https://aemo.com.au/-/media/Files/Electricity/NEM/Network_Connections/Transmission-and-Distribution/AEMO-Standard-for-Power-System-Data-Communications.pdf
[12] The procedure to calculate the factors using FI is not the same used by the Causer Pays procedure, the process is simplified to provide an estimate representation and not a perfect one.

incentive for a generator to reduce data transmission delays so as to increase its PFR-DSCP factors and associated income.

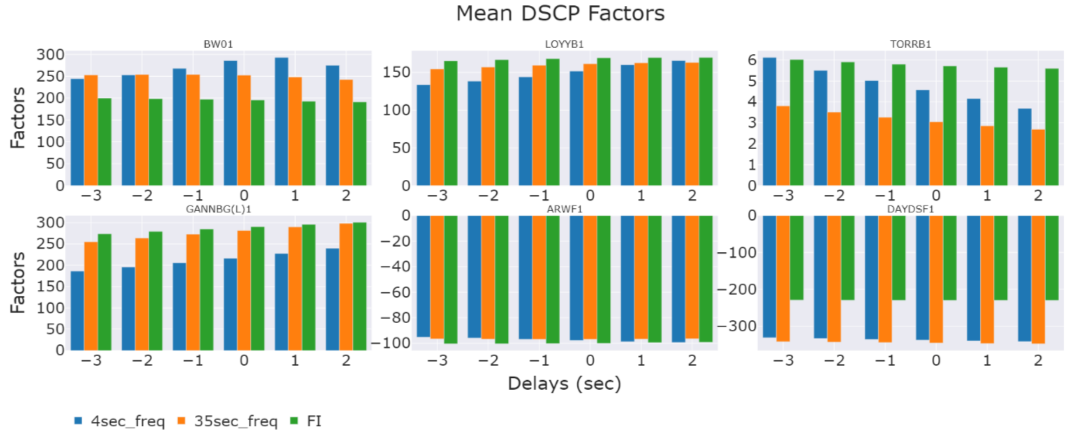
Figure 10 Average of DSCP factors for each delay and each performance metric weighted by capacity



Not all units are the same, hence the factors calculated for each unit may show different levels of variation. Figure 11 displays the average factor for 6 different units:

- Bayswater unit 1 (BW01),
- Loy Yang B unit 1 (LOYYB1),
- Torrens B unit 1 (TORRB1),
- Gannawarra energy storage system (GANNBG(L)1),
- Ararat wind farm (ARWF1); and
- Daydream solar farm (DAYDSF1).

Figure 11 Average factors for different units; top-left) Bayswater unit 1, top-middle) Loy Yang B unit 1, top-right) Torrens B unit 1, bottom-left) Gannawarra energy storage system, bottom-middle) Ararat wind farm, bottom-right) Daydream solar farm



Note: The X axis in this and later similar charts shows multiples of 4-seconds and should be interpreted as [-12, -8, -4, 0, 4, 8]

Different units show different levels of variation of factors across metrics as well as delays. There could be several reasons for the difference; e.g. control settings, ramp capabilities, REG enablement and some of these units may not have been set up to provide PFR at the time.

Some units do have unusually large variation which warrant investigation. For example, TORRB1 exhibits a prominent difference as well (but not in absolute terms as the magnitude is small) and the instantaneous factor has the opposite trend over delays compared to BW01's trend. Also TORRB1's trend over the analysed range does not show a minimum/maximum.

Shared Analysis

The variation across delays appears quite high, with the most prominent difference being between the instantaneous factors and FI factors of Bayswater. However, under DSCP the share of the factors (relative to the sum of like-signed positive or negative factors over the system) is a more relevant quantity than the magnitude of the factor. Figure 12 displays the share of the units' factors relative to the total sum of positive or negative factors. For example, Bayswater has predominantly positive factors, hence the share calculated below is Bayswater's share of positive factors, Ararat wind farm on the other hand has predominantly negative factors, hence the share calculated below is Ararat's share of negative factors. The subplot titles of each chart also indicate the sign of the factor considered.

Figure 12 Share of factors for different units; top-left) Bayswater unit 1, top-middle) Loy Yang B unit 1, top-right) Torrens B unit 1, bottom-left) Gannawarra energy storage system, bottom-middle) Ararat wind farm, bottom-right) Daydream solar farm

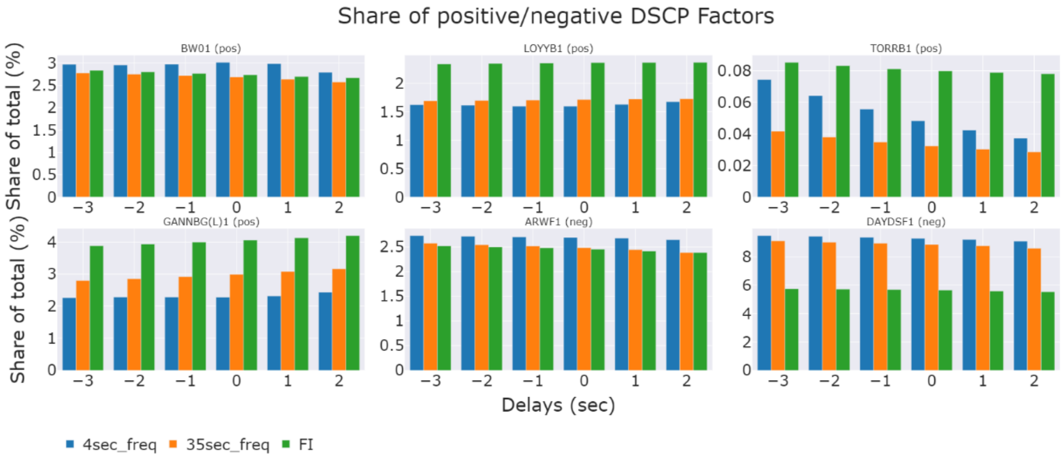


Figure 12 shows that, although the magnitude (absolute value) of the factors may vary across the selected delays, the share of factors of the unit relative to the system does not vary significantly in most cases. This conclusion assumes that delays are relatively uniform. This suggests that DSCP transactions for the purpose of small deviation correction would not be significantly affected by reasonably uniform time delays. Outlier cases with SCADA transmission delays longer than the 6-seconds permissible in the SCADA standard would introduce much larger errors. These represent a minority of the measurements and are not expected to present an issue because they should comply with 6 second standard in any case.

Contingency Events Analysis

Time delay error could be detrimental in the allocation of costs after a contingency event. Consider the 30-minute period relating to such an event in Figure 13 following. Bayswater unit 4 tripped, resulting in a very large negative frequency. Bayswater 1 was enabled for contingency and quickly increased its generation. Being at the same site, the SCADA transmission of these two measurements would not incur any difference in transmission delay.

Under DSCP Bayswater 1 would get paid for its positive frequency support and Bayswater 4 would be liable to pay for causing the depression in frequency. The case where there is a delay in transmitting MW data to AEMO is shown in Figure 13. While frequency error, MW response and DSCP factors would be relatively high in the first few seconds (and in error to the extent that this was due to data transmission delays), the frequency deviation from the event is still being corrected after as long as 5 minutes and so any error in the response due to a few seconds delay, while large for those few seconds, is relatively small compared to the factors incurred for the whole event. Another consideration is that contingency events are uncommon.

Figure 13 Response to trip of BW04 and enabling of BW01 - no signal delay

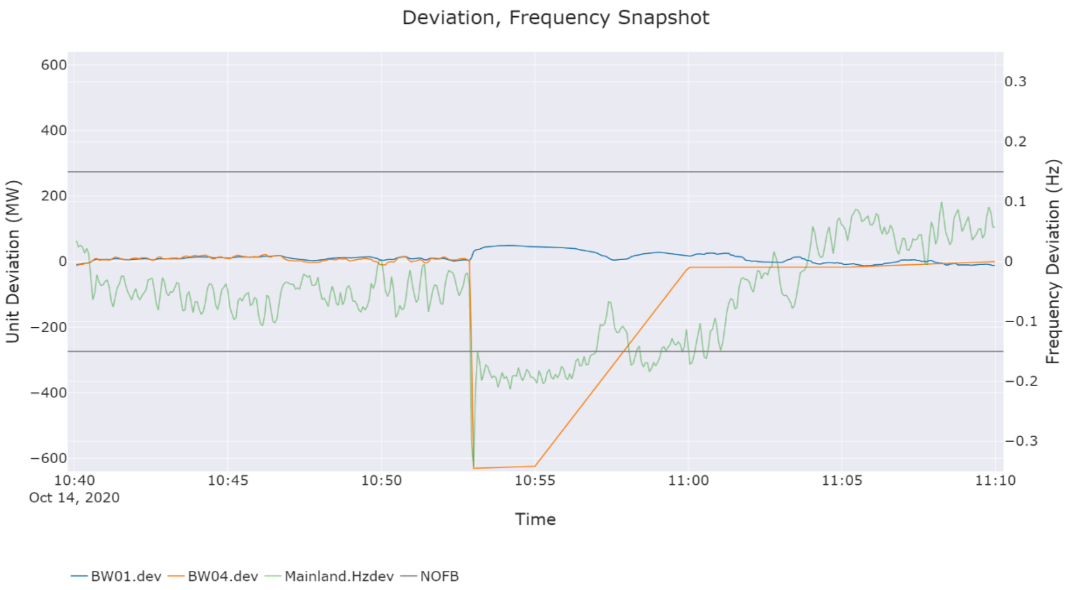
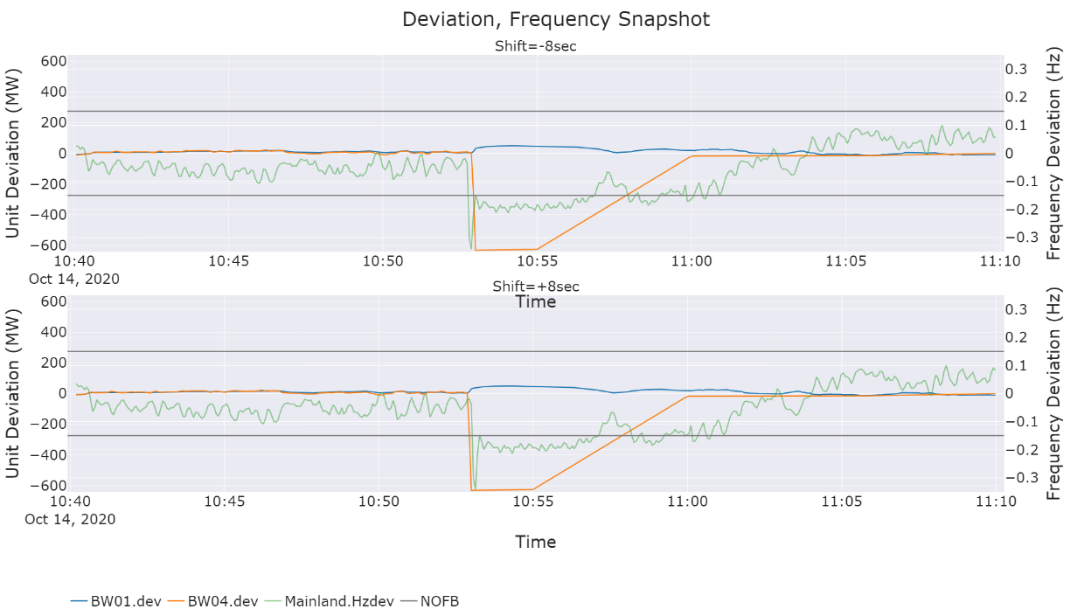


Figure 14 Response to trip of BW04 and enabling of BW01 – with signal delay



Possible options to deal with settlement of DSCP during contingency events are:

- Live with the errors on the grounds of their relative rarity and to reap the benefits of small deviation support in restoring frequency after the initial frequency excursion.
- Update the maximum permissible SCADA delay from 6 seconds to a much smaller value
- Install high resolution local metering suitable for DSCP settlement

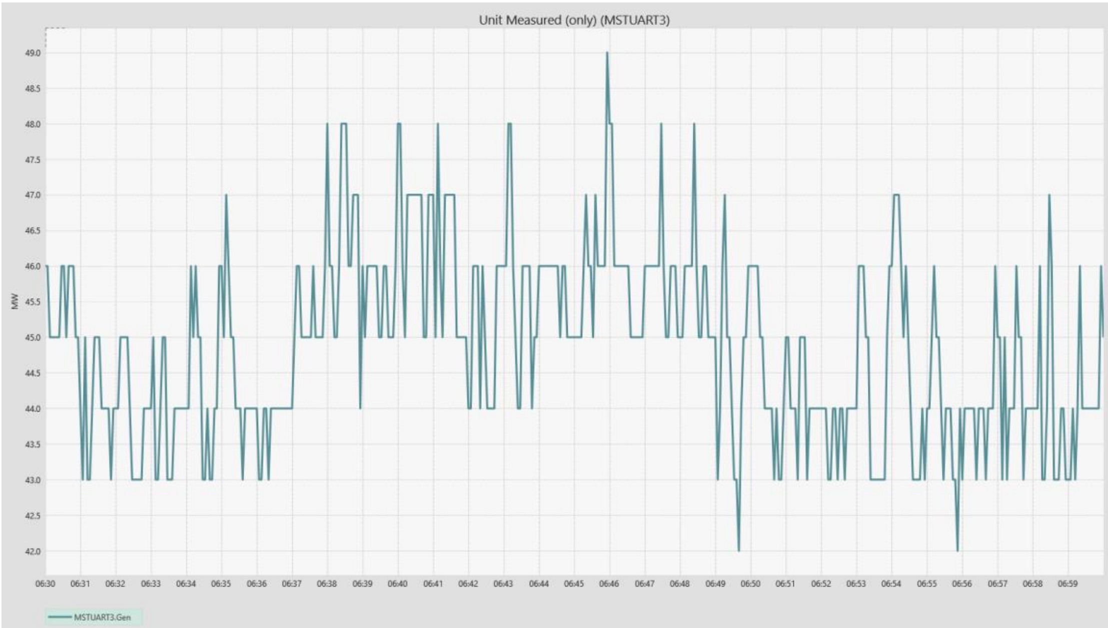
- Cap the DSCP price at a level corresponding to the frequency at the edge of the NOFB
- Remove contingency periods entirely from the settlement calculation

We prefer the first option on the grounds of adequate accuracy, simplicity and robustness.

3.2.4 Discretisation error

There is a resolution requirement in the SCADA comms standard, but its units are in "percentage of range". For power, the resolution typically turns out to be 0.5 or 1 MW as shown in the example following.

Figure 15: Snapshot of MSTUART3's measured output



The potential for error is greatest when the deviations are small relative the coarseness of the measurement resolution. It is possible to construct an artificial example where there is a constant error (half a MW resolution, assuming rounding to the nearest discrete value) the deviation from trajectory. In practice, though, even a small amount of variation will result in factors that are positive or negative in error and indeed near normally distributed (consistent with the central limit theorem over many samples, such as over one or more settlement periods).

For most participating units, the effect of discrete measurements of coarse resolution will be to introduce random error into the factor calculations, similar to the random errors discussed below.

3.2.5 Random Error

We define random error as a residual error caused by miscellaneous uncontrolled and even unknown factors. The expected value is zero because any persistent offset is corrected. e.g. by calibration of scaling factors. The variance when measured over a relatively few samples may be significant but the variability tends to become less material relative to the mean as the number of samples increases to a numb, such as to the number of samples in a settlement period.

3.2.6 Communication Outage Error

The data communication standard enforces a reliability requirement on all data providers, it is the provider's responsibility to ensure the presence of redundant elements to meet the reliability standard. Currently the reliability requirement states that over a 12-month rolling period the total period of outages should not exceed 6 hours.

In the long-term this may not cause a significant problem to the system, but in the short-term (typically during periods high frequency/energy prices) a unit with no data may circumvent the proper allocation of costs. For example: if during a high frequency event, a unit with large excess MW deviations (which is making the supply-demand balance worse) would be liable for higher share of the costs. If there was an outage the unit would benefit in the absence of an alternative mechanism to allocate costs. For situations like this an alternative mechanism is required to maintain the incentives of the DSCP mechanism.

One approach is to include the unit with no data in the residual. The residual is almost always likely to be a net consumer of frequency response and hence a payer under the DSCP procedure. Treating the unit with no data as a residual would incentivise the participant to invest in more redundant communication infrastructure to avoid any outages. Since the residual costs will be distributed based on metered energy, this incentive increases with unit size.

Another approach is to calculate an expected factor from previous periods where data was available. If such an approach is chosen, the procedure for the calculation must be carefully considered and consulted on. Complexities in the procedure may lead to unforeseen and undesired consequences for participants.

As the residual is defined as load or generation without metering, including a unit with missing data in the residual seems to be the logical approach.

3.2.7 Time Resolution Error

Time resolution error is the error that may arise because frequency and MW deviations are measured at discrete time intervals; 4 seconds on the mainland and 8 seconds in Tasmania. Frequency and MW deviations measured over these intervals will typically differ from the same measurements made at, say, 50ms intervals in a high-resolution meter. As high-resolution metering for DSCP would be a desirable direction to move in and requires time to implement fully, we also seek to ensure that metering data of different resolution can be used in a single DSCP settlement system during the implementation period.

The limiting and most accurate value of a frequency or MW measurement occurs as the interval approaches zero – in practice a few cycles are normally required. How can we make this compatible with 4 second measurements which report average values over the previous 4 seconds? The answer is to apply a 4-second low pass filter to the high-resolution data as is suggested by control theory. So 4-second and 35-second frequency values are obtained by applying filters of 4 and 35 seconds to the raw high resolution frequency data[13]. Filters with the same time constants are also applied to the 4 second data. In this case applying a 4 second time constant filter reproduces the raw 4 second measurement. We note that a high-resolution measurement filtered with a 4 second time constant will differ somewhat from a raw 4 second measurement but can be considered more accurate for the purpose.

It would not be practical or necessary to transmit high resolution data obtained from local metering to AEMO, except for occasional testing purposes. Values suitable for settlement can and should be accumulated within the meter into 5-minute values suitable for settlement. To ensure compatibility between metering data with differing time resolutions, 5-minute cumulative values for settlement should be recorded and uploaded to AEMO as averages rather than totals, independent of the time resolution.

We note that high resolution metering could also support measurements of Fast Frequency Response (FFR) and even inertia through Rate of Change of Frequency (RoCoF) measurements for applying DSCP settlement logic.

We also note that 10 second data is the SCADA standard in Tasmania. However, if Tasmanian performance factors are treated as averages in settlements, they would be compatible with mainland factors and so no low-level interpolation would be required.

3.3 Other Metering Options

3.3.1 Motivation to improve DSCP metering

The previous discussion confirms that using SCADA metering to measure DSCP performance is less accurate and reliable than that required for revenue metering. As the use of such metering applies to a relatively small component in the total cost of delivered energy, any absolute inaccuracies are relatively small and acceptable in the absence of better options. Many other ways of allocating costs and encouraging performance are much cruder, including obtaining performance by mandating it.

Nevertheless, exploring options for more accurate and reliable metering offers the following benefits:

- the DSCP process when applied to PFR and secondary control would be more reliable and accurate;
- DSCP logic could be applied to faster-acting services, including FFR and inertia;
- Potentially, DSCP participation could be offered to embedded generation units and loads at modest up-front cost, by avoiding the requirement for reliable real time communications.

Some options are explored in the following sub-sections

3.3.2 General high-resolution metering

There are many power quality meters on the market designed to record at very short intervals, (of the order of a few cycles), used for troubleshooting on a spot basis or when some incident is detected, such as frequency falling outside a specified range. Such

[13] IES, *A Double-Sided Causer Pays Implementation of Frequency Deviation Pricing- Control and Pricing and Theory Report*, 14 July 2021, page 18

unmodified meters, while they may accurately record real and reactive power, frequency and power quality, will not be suitable for supporting DSCP as they are not designed to capture, calculate and accumulate factors suitable for DSCP settlement within the meter. Further, it would be impractical to record locally and then, upload, store and process at AEMO data generated at intervals of, say 50ms. Such equipment has most of the required hardware functionality but needs revised firmware.

3.3.3 Dedicated high resolution metering

Standard electronic meters at a very high sample rate of a few hundred samples per second. They measure instantaneous voltage and current and simply multiply the two together and accumulate to record energy over a chosen interval such as 5 or 15 minutes. Other power quality values are also calculated digitally.

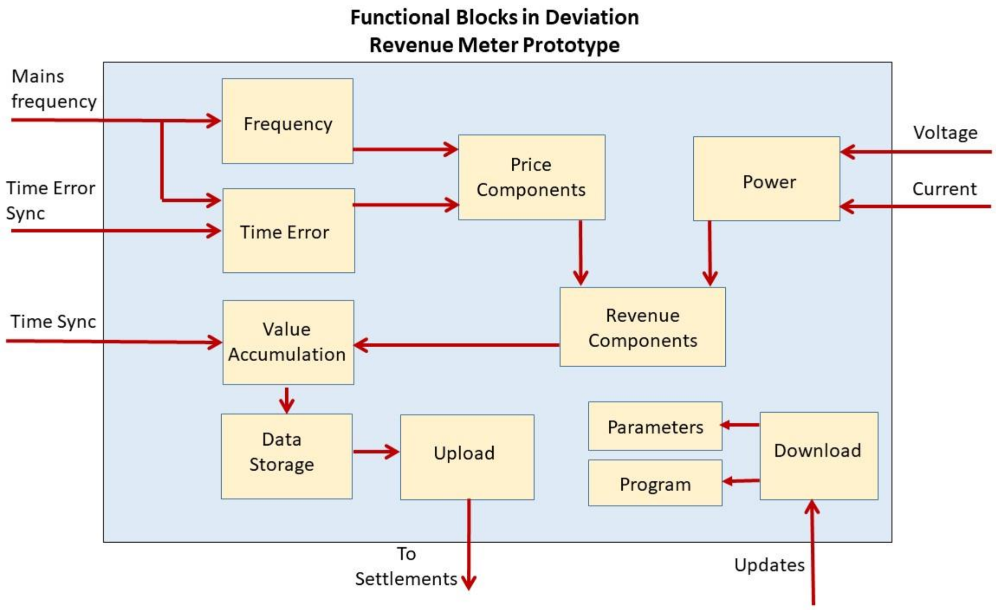
DSCP settlement logic is based on separable price components, each based on a simple filtered frequency formula. We can envisage a meter which:

- measures frequency, voltage and current at, say, 50ms intervals;
- calculates a set of pricing components as well as power;
- multiplies the pricing function components with power;
- averages the results over 5 minutes;
- records these 5-minute values; and
- uploads them to a settlement agent on request e.g. every day.

These calculations can be arranged so that any weightings and reference trajectories can be applied to the 5-minute values at the time of settlement. By keeping these latter calculations away from the meter, the meter itself can be made to operate independently of any requirement for real time injection of weightings, MW targets or dispatch prices and therefore as robust as a standard revenue meter.

Such a meter is essentially the same as a current revenue meter but has enhanced firmware that does more in-meter calculations than a standard meter. Figure 16 shows a functional diagram of a DSCP meter. It could be programmed to include chosen DSCP components, such as PFR, secondary response and even FFR and inertia. It could operate alongside a standard energy revenue meter, or also include raw energy measurements and replace a stand-alone energy meter.

Figure 16: Functional diagram for a dedicated DSCP meter



We note that metering as described would be suitable not only to replace the use of SCADA for scheduled participants but would also allow non-scheduled and embedded parties to participate in DSCP on an opt-in basis. By so doing they could avoid the DSCP charge to the residual which would otherwise be more difficult to avoid. Aggregators could promote DSCP participation to embedded customers, implement suitable metering and upload data, which could then be aggregated and forwarded to AEMO for settlement. Suitable regulations could be developed to protect embedded customers.

3.4 Conclusions on Metering

- While errors from various causes in SCADA metering are higher than for revenue-grade metering, they have been used to measure and settle AGC regulation enablement costs under Causer Pays adequately for many years.
- However, SCADA transmission delays distort PFR significantly more than they affect AGC regulation or similarly filtered values. Within the allowable delays of 6 seconds under AEMO's SCADA standard, underestimation of up to around 5% may be expected. However, to the extent that delays are reasonably uniform and of only a few seconds, the shares will be relatively little changed and settlement little affected.
- We understand that some units still suffer from extended data transmission delays. In these cases, the factors used to assess the amounts paid to generators receiving payments can be improved by reducing those delays, an appropriate incentive.
- Review of the effect of contingencies on DSCP settlement suggests significantly larger than average error for one or two 4 second intervals at the onset of a contingency, due to delays in data transmission. However, recovery from the contingency event takes place over a much longer period, potentially of order 5 minutes, so the error from transmission delay becomes less significant in relative terms over the duration of the incident. Further, contingency incidents are relatively rare. Therefore, we

recommend that no special adjustments be made to DSCP settlement when there is a contingency event, in the interest of maintaining simple, unambiguous settlement logic.

- DSCP settlement would be more accurate and reliable with local high-resolution metering instead of SCADA metering. General-purpose high-resolution metering is unsatisfactory because of the high burden of data transmission, storage and settlement calculation at AEMO.
- It is possible to design a dedicated meter which measures, calculates and accumulates factors into 5-minute packages which can be practically uploaded and settled by AEMO. Further, values suitable for settlement of DSCP applied not only to PFR and decentralised regulation, but also to FFR and even inertia. This could be a relatively standard electronic meter but with adjusted firmware.
- With the availability of cost-effective DSCP metering, embedded customers could participate in DSCP on an opt-in basis through an aggregator.

4 Development of Analytical Tools

We document in this report two models capable of analysing options for DSCP/FDP in different ways.

4.1 Control and Pricing Model

The functionality of this model is outlined in Appendix A. The aim is to optimise and simulate the control and pricing of an indicative electricity system. Using this tool some of the more technical design and performance issues of a DSCP/FDP system can be analysed.

At the time of drafting some desirable reporting features of this model had yet to be developed. These are marked in the appendix with "to be developed".

4.2 DSCP Back-casting Calculation Procedure

With the release of the AEMC draft determination in September 2021, it became evident that analysis and comparison based on historical data would be beneficial to the project. Many of the tools to do this were developed for the performance assessment part of this report. However, they needed further development to allow comparative analysis of system design options. These developments are described in Appendix B.

5 Conclusions and Next Steps

In this report we addressed a set of quantitative issues that would need to be resolved before settling on a proposed DSCP design, which will be included in our final report. Those issues are.

- What scope is there to improve frequency control performance and in what way?
- Is SCADA metering an acceptable way to kick start a DSCP approach and how could metering be improved over time?
- How does one set DSCP prices used in settlement and how does any selected approach look when applied to real data?

There are issues nominated in our Inception Report that require an operational model of a representative system to help resolve. At the time of drafting of this report we have made progress with such a model but it was not ready to perform studies. The model is described in Appendix A of this report. We will publish results in the Final Report of this project when the model is more complete. The issues to be addressed include:

- System behaviour with DSCP when
  - lower inertia will tend to make the system frequency more sensitive to power imbalances, all else being equal; and when
  - the variability of disturbances affecting the requirement for PFR and regulation FCAS, driven by increasing penetration of variable renewable energy, is expected to be larger.
- System behaviour with battery proliferation
- Incentives for stabilising behaviour and for bad behaviour, if any.

We have also developed a procedure to analyse DSCP/FDP options by back-casting using historical data. This is not a complete tool as it takes no account of the incentives that DSCP/FDP provides. However, such analysis is a useful starting point for understanding impacts and incentives.

The conclusions from the analyses in this report are briefly summarised as follows.

- The mandatory PFR rule introduced by the AEMC, National Electricity Amendment (Mandatory primary frequency response) Rule 2020 No. 5 and implemented by AEMO with effect from 4 June 2020 has been successful in improving system frequency performance. However, this has been achieved substantially from plant that is expected to be phased out over the next decade or two. There remains the challenge of how to muster resources efficiently to achieve adequate frequency performance.
- SCADA metering is subject to a range of error sources, more so than dedicated revenue metering. The likely largest source of error is the potential delay between measurement at a site and its receipt by AEMO. A DSCP measures such as raw frequency is more sensitive to measurement delays than a smoothed frequency measure, including the FI measure used by the AGC. For compliant units with data communication delays less than 6 seconds, the error is mostly bounded but there are likely to be pathological cases. A program to develop and roll out dedicated DSCP meters would certainly resolve this issue but should not be required for an initial

implementation. The possible need for upgrade of some communication facilities and the associated cost needs consideration at the design stage.

- This analysis also highlighted some likely design choices related to metering, including:
  - Units with missing or poor-quality data should be treated as part of the residual for affected dispatch intervals; and
  - The DSCP/FDP system should continue to operate during a contingency event.
- We have developed code which can process SCADA data for notional DSCP settlement using various design parameters. This will be used to further tune and stress test our final recommendations, along with the operational modelling foreshadowed in our Inception Report.

Appendix A FDP/DSCP Model Development

A.1 Introduction

We seek to specify and develop a model to demonstrate the key features of FDP/DSCP pricing, settlement and control. We cannot expect to use such model to determine the parameters of participant response and therefore key pricing parameters. However, we can expect to derive and test the form of a pricing formula and to test its operation on a simplified system. We can explore the sensitivity to parameters such as system inertia and increased penetration of variable output renewable plant as well as plant with a fast response characteristic such as batteries

A.2 Model Requirements

For simplicity our modelled network will:

- focus on real power;
- incur no losses; and
- be free of constraints on regulation

The system will support the inclusion of any practical number of generators and loads and will model their deviations from forecast in the case of loads and scheduled output in the case of generation.

Normally a single load will be sufficiently detailed. The load will:

- have a nominal size in MW
- have property of inertia (resistance to acceleration)
- have damping (PFR) property (response to frequency deviation) and associated quadratic cost
- be subject to random disturbances modelled as a Weiner process (where the variance in increases over time
- larger step changes are also supported
- also revert to the mean at a rate determined by the reversion time constant.

Each generating unit will:

- have a nominal size in MW
- have property of inertia (resistance to acceleration)
- have damping (PFR) property (response to frequency deviation) and associated quadratic cost
- be subject to random disturbances modelled as a Weiner process (where the variance increases over time
- be subject to a ramping controller and a corresponding quadratic cost

We seek to derive a controller which is optimal for the system being modelled i.e. both stable and least cost. A Linear Quadratic Regulator (LQR) is such a controller but may not be practical to implement. However, as an optimal controller it provides a robust reference cost and performance.

The NEM is operated to achieve a performance standard, If the controlled variables are frequency deviation and time deviation and the measure of performance is the square of a linear combination of these two outputs, we can optimise the performance of the system by defining a target variance on the controlled variables and minimising the costs of achieving that target. This can be achieved by:

- adding the quadratic performance (variance) to the control cost with a weighting factor;
- Find the controller that optimises the combination; and
- systematically adjusting that weighting to achieve the desired target.

This procedure guarantees that the target is achieved at least cost. This in turn allows the evaluation of a practical controller (such as one relying solely on local measurements) relative to an idealised controller, as well as compare different practical controllers.

The system should also support adjustments to important implementation parameters such as the sampling interval. While the generator and load models are over-simplified, they capture the key elements of this dynamic system e.g. the costly and delayed ramping characteristics of many classes of real generators that are not captured in the energy market. In this model the so-called “swing equation” plays the balancing and pricing role of the energy balance constraint in energy market dispatch models. The swing equation contains inertia and damping (PFR) terms that are missing in dispatch models.

A.3 Implementation

The modelling system outlined above has been written in MATLAB with the app designer object used to provide a Graphical User Interface (GUI). The data entry and display of results is resented in a series of Tabs as described below.

A.3.1 Data Entry Tab

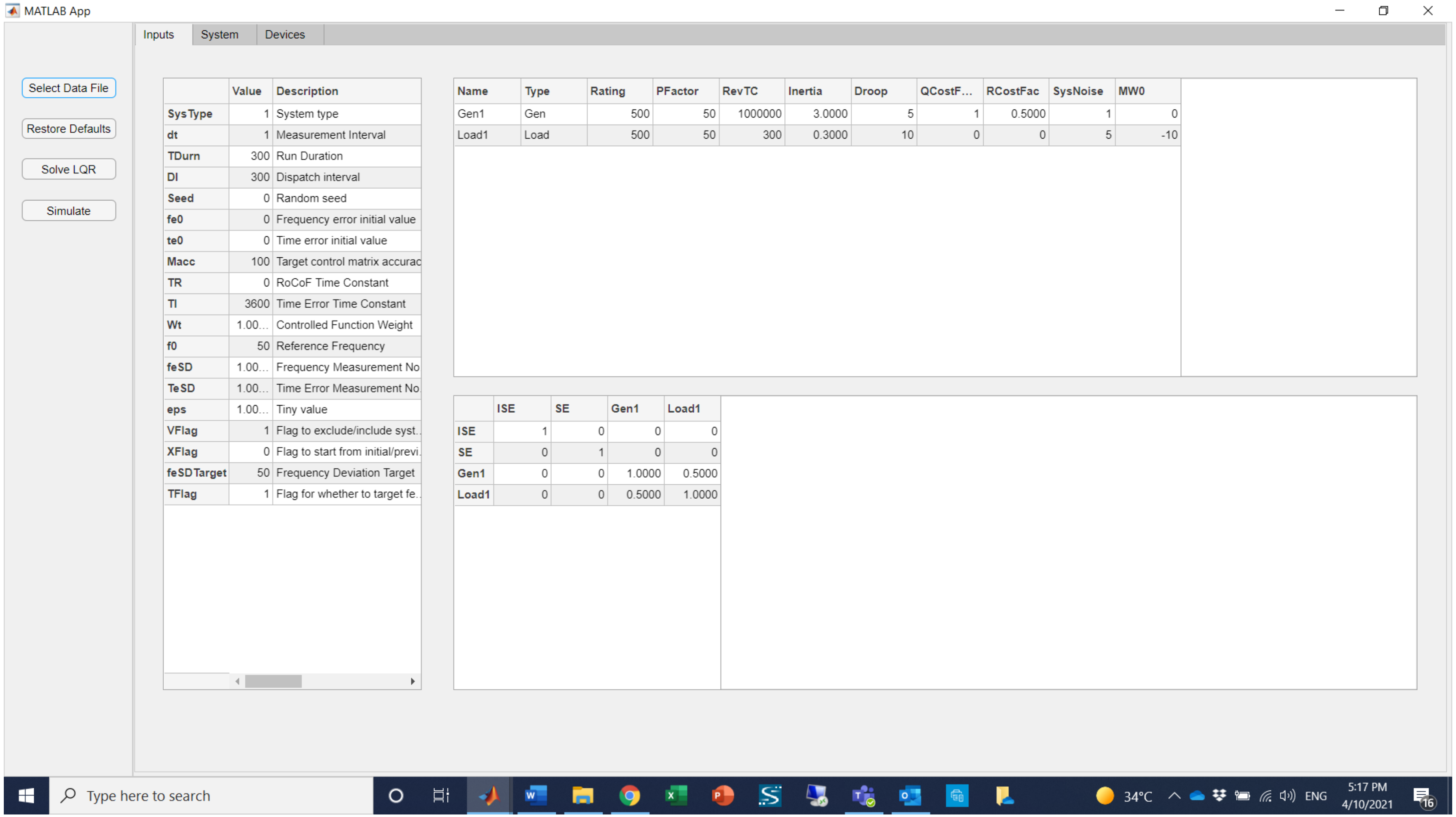
Raw data is managed in a spreadsheet and loaded using the Select Datafile button. Once loaded data items can be adjusted easily and quickly. The defaults from the selected file can be restored quickly with the Restore Defaults button. A sample of the data screen is presented in Figure 17 following.

The screen is divided into 3 parts.

- On the left are system wide parameters describing the system and options for the run. Not all options are implemented at the present time.
- On the top right are the properties of the system devices e.g. generators and loads. For convenience, generators and loads ae modelled with identical parameters, although some parameters are effectively disabled in each case. As many devices can be added as necessary to reasonably represent the structure of the system. By convention, all injections, whether from loads or generation units, are taken to be positive. Batteries can be represented with separate loads and generators but with parameters such as the ramping quadratic cost coefficients approaching zero to reflect their high ramping ability.

- At the bottom right is a correlation matrix describing the cross-correlations, if any between the different noise sources modelled. When combined with the standard deviation/variance of the disturbance, we can construct the covariance used to model disturbances in the LQR model.

Figure 17: Example of Data Entry Screen



A.3.2 Main Results Tab

To run the model, the user first solves for the optimal controller using the solve LQR button. The solution can optionally be automatically tuned to target the standard deviation of frequency. With the optimal controller available, the user can then run simulations by hitting the Simulate button. Run parameters such as run duration and turning disturbance off and on can be adjusted from the Data Entry Screen. The Main Results Screen, Figure 18, contains four charts as described below, beginning from the top left and moving clockwise.

Power Balance Components

This chart consists of four line-plots

- the load (purple)
- injections and offtakes due to generation system inertia, summed over all units (blue)
- injections and offtakes due to generation damping (PFR), summed over all units (red); and
- injections and offtakes due to generation secondary control (e.g. AGC), summed over all units (orange).

Note that the sum of the generation components equals the load.

In this example the inertia contribution is usually relatively small expect in the first few seconds because the system starts out with a moderately large frequency offset. The damping contribution ranks next and it varies positive and negative because the system is under good control. However, the system secondary controls are biased positive in this example, mirroring the general drift of the load. This example highlights the distinction between primary and secondary controls. Pricing that addresses secondary control will sometimes work in the opposite direction to primary control. One would expect plant with different capabilities to respond to each component.

System Deviation Price and System Costs

This chart shows (in red) the rate of system costs incurred, consisting of offset cost and ramping cost summed over all units and loads. Note that costs are always positive. The deviation price is shown for comparison.

The legend also shows the standard deviation of the system cost in theory (marked T) and as modelled in the simulation or modelled (marked M). The theoretical and simulated values are reasonably close and become closer for longer simulation periods.

System Time Constants

The controlled system when undisturbed will gradually revert to zero. The rate at which that occurs is a complex function of the structure of the decay matrix. We can analyse the structure of the matrix and the nature of the decay process by performing an eigenvalue decomposition, the eigenvalues of which are displayed in the bottom right chart.

Figure 18: Main Results Screen

In this example all the eigenvalues are real numbers and vary widely. The longest time constant can be associated with the weighting given to the time deviation relative to frequency deviation. Time constants of the order of minutes are associated with the mean reversion behaviour of the load. Shorter time constants of the order of seconds are associated with PFR and secondary control. In this example there are no imaginary parts of any eigenvalue which would indicate an absence of (damped) oscillations. Eigenvalue analysis can also indicate the structure of a simplified controller, very close in performance to the ideal.

Frequency and Time Deviations

The bottom left chart shows plots of frequency and time deviations.

Note that the time deviations move much more slowly than frequency deviations.

This plot also displays in the legend the theoretical and simulated standard deviation of frequency. Again, over long periods or over many simulations, the simulated values converge to the theoretical ones.

A.3.3 Unit Results Tab (to be developed)

Th Unit Results Tab displays a set of charts very similar in structure to the those in the Main Results Tab, but at the unit level. A placeholder is shown as Figure 19. A selection drop-down list will be displayed on the left-hand pane. Each of the four charts is described below.

Power Balance Components (to be developed)

This chart consists of three line-plots

- injections and offtakes due to generation or load inertia;
- injections and offtakes due to generation damping (PFR); and
- injections and offtakes due to generation secondary control (e.g. AGC – only present for generation).

Deviation Price and Unit Costs (to be developed)

This chart shows the rate of system costs incurred, consisting of offset cost and ramping cost. Note that costs are always positive. The deviation price is shown for comparison.

The legend also shows the standard deviation of the unit cost in theory (marked T) and as modelled in the simulation or modelled (marked M). The theoretical and simulated values are reasonably close and become closer for longer simulation periods.

System Time Constants (to be developed)

The controlled system when undisturbed will gradually revert to zero. This plot shows the weightings used for controlling ramp rate by the unit when responding to each price component, noting that the control (ramp rate) components are directly proportional to the price components.

A.3.4 Frequency and Time Deviations

The bottom left chart shows plots of frequency and time deviations. This plot is identical to the system-wide chart and is included for convenience of reference.

Figure 19: Unit Results Tab (placeholder)

A.3.5 Performance of simplified controllers (to be developed)

For any given data set we can consider:

- the LQR (idealised) solution; and
- the solution with a simplified, more practical pricing logic.

The cost of the second relative to the first is a measure of the potential efficiency of the pricing method.

We can also envisage doing two sets of simulations, with each driven by the same set of disturbances. We can produce all the plots described above in each case. We propose to pre-calculate the simulation results and to switch display of each data set with a toggle button on the left-hand panel.

Appendix B DSCP Back-casting Calculation Procedure

B.1 Introduction

To investigate the impacts of implementing DSCP, a procedure has been developed and the cost allocations for each unit during a historical period calculated and analysed. This is a preliminary procedure and can be changed as the project is consulted on. The principles of the procedure are listed below, these principles are informed by the theory of deviation pricing discussed in the previous theory report.

The proposed procedure is very similar to the current causer pays procedure; it can be broken down into the following high-level components:

For each unit, link and residual:

- Define regions and residuals,
- Calculate deviations,
- Calculate factors,
- Calculate weighted factors,
- Calculate settlement amount; and
- Note frequency deviation pricing interpretation.

B.2 Regions and Residuals

B.2.1 Basis for a regional analysis

We propose that this DSCP arrangement operate on a regional basis as we propose to weight performance measures by some local parameter reflecting a requirement to maintain these services on a regional basis, at least to some degree. AEMO argues that diversity of supply leads to a more robust system. Suitable weightings could be DI energy prices or costs, or DI regulation enablement prices or costs.

We can undertake a regional analysis of the DSCP process as a closed system, by regarding interconnectors as sources or sinks and the residual as the negative of the total of all metered power and energy (noting that this definition lumps losses in with the residual).

Links and residual are treated in a same manner as units, i.e., factors and settlement amounts are calculated for them. In the case of the residual we need a way to allocate what will always be a cost assigned to them; pro-rata according to energy consumed is a good measure. Interconnectors may produce a deficit or surplus because of the price difference possible on each side of the boundary, even though power and energy are conserved at the boundary. This usually small amount could be allocated in proportion to the measured degree to which each region receives PFR and regulation support across the interconnector during the DI.

B.2.2 Calculation of the residual

DSCP participants are those who are scheduled and are suitably metered (currently with SCADA AGC metering) or unscheduled but metered and participating. We define the residual as the negative of the sum of the metered power/energy. In all respects other than its lack of high-resolution metering, the residual behaves like any other DSCP participant and is affected by inertia, damping/load relief and controlled changes as frequency varies. This definition is justified as follows.

Within a region, AEMO makes forecasts for the non-scheduled load, taking account of self-forecasts. Plant and interconnectors are scheduled by the dispatch engine to achieve an exact power and energy balance (within model accuracy). That balance applies for the system as a whole or for any part of it, such as a region, enforced by the dispatch engine. The actual realisation of demand will invariably differ from forecast and some plant may not follow schedule. Various forms of FCAS are dispatched to keep frequency within bounds. Regardless of what is done, by the laws of physics the system must remain in electrical balance, even though frequency might be varying a lot. Since the schedule and the outturn powers must each sum to zero, the sum of all deviations (the sum of the differences) must also be zero. Thus, we can infer the deviations of the residual indirectly (as the negative sum of the metered provision), even though we cannot measure them directly.

Note that the residual, which is based on actual outturns relative to a forecast, already includes an element of load relief, an estimate of which is usually taken as the regulation requirement. It does not need to be separately accounted for in the deviation balance.

B.2.3 Deviations

The deviations of a unit are essentially the difference between what was measured and what was scheduled, with some possible variations around that theme. We have considered 4 profiles for calculating reference trajectories:

- Dispatch target to target linear ramped trajectory
  - This is the same as the trajectory used by the current causer pays procedure
- Dispatch target to target linear ramped trajectory plus AGC-REG component for regulation enabled units
- Measured Initial MW to dispatch target linear ramped trajectory
- Measured Initial MW to dispatch target linear ramped trajectory plus AGC-REG component for regulation enabled units

In the example we provide later, we use the target-to-target option, which sems to be the more natural approach as it ensures there are no deviation discontinuities between DIs (although there may be price discontinuities). Note that the choice between target-to-target and Initial-MW-to-target may affect the settlement variance but only weakly, if at all, the expected or mean settlement outcome.

In our example we do not include the AGC trajectory in our reference trajectory i.e. the DSCP price would apply to enabled units as well as non-enabled units and act as a supplementary incentive. If the AGC trajectory is included, AGC-enabled units would be indifferent to the DSCP incentive or even discouraged from becoming enabled, given the new income streams available outside enablement with DSCP implemented.

B.2.4 Units

The trajectory for a metered unit can be calculated using 5-min market data; the deviations are calculated as the difference between measured values and the scheduled trajectory.

$$Deviation_{unit} = Measured_{unit} - Trajectory_{unit}$$

B.2.5 Links

Each interconnector is represented by 2 imaginary plants residing in either side of the interconnector. For example, the V-SA interconnector is represented in the data as VTSASA residing in SA and VTSAVIC residing in VIC. This is done to treat each region as a separate area. As an aside, the revenue differences between the 2 imaginary plants should indicate how valuable the interconnector is for frequency control.

The scheduled initial MW and measured flow of the interconnector is made public by AEMO and hence a trajectory and deviation can be calculated for each interconnector, in the same way as for units. These quantities have a sign identifying which direction the interconnector is flowing; based on this direction the imaginary plant deviations are calculated. For example, V-SA flow is positive when flowing from VIC to SA, hence VTSASA's deviations will be equal to the interconnector deviations while VTSAVIC's deviations will be the negative of the interconnector's deviations.

$$Deviation_{interconnector} = Measured_{interconnector} - Trajectory_{interconnector}$$

$$Deviation_{link\_imp} = Deviation_{interconnector}$$

Where: $link\_imp$ is the imaginary unit residing in the importing region of the interconnector.

$$Deviation_{link\_exp} = -Deviation_{interconnector}$$

Where: $link\_exp$ is the imaginary unit residing in the exporting region of the interconnector.

For the purposes of the rest of the procedure, the imaginary units associated with each interconnector are treated just as other units are treated.

B.2.6 Residual

The residual represents the sum of all unmetered grid connected devices. In this procedure a residual component for each region is calculated as below.

$$Dev_{region} = -\sum_{units\ in\ region} Dev_{unit}$$

Note that units also include the imaginary units of each interconnector residing in the region. The equation recognises that energy is balanced at every moment, i.e., sum of all deviations is zero. This also implies that electricity losses are attributed to the residual. This also ensures that the settlement amount is balanced if the residual is included.

B.3 Factors

B.3.1 Performance factors

The performance factor (as causer pays described it) is a measure of how well a unit assisted in the control of frequency or reduced the need for regulation causer pays. Under the causer pays procedure, this was calculated as a product of a unit's deviation and FI.

In the theory report, a basis was provided to use smooth functions of frequency instead of FI as the performance metric. In our investigation we have used 2-time constants:

- 4sec, reflecting instantaneous response as measurement frequency is 4 seconds
- 35sec, reflecting the perceived AGC response

The 35sec metric is slow moving and indicates how the procedure can be used to reward a slow regulation response while the 4sec can be used to reward faster PFR type of response. The relative gains applied to each metric or price component are tuning parameters that can be used by AEMO to adjust the incentives for participants to deliver the required frequency performance.

$$Factor_{unit,\, tc} = Deviation_{unit} * f(-Hz,\, tc)$$

Where; $f(x, tc)$ is a smoothing function of the variable x with time constant tc.

These factors, 4 second or shorter, can be aggregated to 5-minute values and stored for ease of later processing for settlement.

B.3.2 Weighting Factors

The factors as calculated in the previous section and under causer pays do not reflect the value of location or values at different times. i.e., units providing frequency response from a location of expensive, scarce reserve should be renumerated higher than units providing response from a location of abundant reserve. In this way DSCP could encourage geographical dispersion even when not constrained to do so. Further, we seek to encourage a robust technical response to DSCP incentives even as energy and regulation prices vary by orders of magnitude at different times and locations.

This type of response can be encouraged by weighting the factor calculated above by a weighting metric reflecting the expected cost of reserve. We have considered 4 options to reflect the cost of reserve

1. Constant (constant over the DI) regulation price for each region
2. Energy price for each region (e.g. absolute regional energy price with a constant floor), applied uniformly across the whole DI.
3. Regulation enablement price for each region (possibly distinguishing raise and lower, also applied uniformly across the whole DI).
4. Ramped versions of 2 ad 3 above (e.g. dispatch price to dispatch price) to avoid deviation price discontinuities at DI boundaries.

In our sample analysis we have chosen option 2 for illustration, but this does not imply that we strongly recommend it. This issue requires further consideration. Uniform weightings are slightly easier to implement and understand than the price-ramped versions but have the disadvantage of giving a DSCP price discontinuity at the boundary between DIs. However, this discontinuity need not be a huge problem so long as weightings are chosen for participants to remain indifferent between operating with DSCP or energy at a particular level as the system traverses a DI boundary.

$$WFactor_{unit,tc}=Factor_{unit,\ tc}*Weight_{region\_of\_unit}$$

Note that a DSCP system could be configured to allow switching between options.

B.3.3 Settlement

In the theory report, we showed that each DSCP price component had a gain associated with it that could have been calculated if technical parameters and cost functions of all participants were known. Since this is not possible, we propose that the weighting factors from the previous section to recognise variability in the willingness to supply. However, we require another tuneable "global" level factor to reflect overall responsiveness and how much one wants to rely on DSCP relative to enablement.

$$Settlement_{unit,tc} = SettlementConstant * WFactor_{unit,tc}$$

B.3.4 Settlement Constant Calculation

To keep DSCP prices within a realistic range, one approach is to set *SettlementConstant* to yield a total DSCP component settlement amount to be a fixed fraction of total regulation costs for some historical period. *SettlementConstant* should be calculated ahead of use so that participants can monitor and effectively respond to DSCP prices in real time. A simple procedure that accomplishes this is provided below:

Given:

- Any historical period (e.g. first week of May 2021) and
- the target ratio of DSCP costs to regulation costs (e.g. $\text{TARGETRATIO}=10\%$)

Then do the following:

1. Calculate sum of all weighted factors of all units (including links and residuals) and preconfigured time constants and gains
$$WFactorSum = \sum^{Over\ period} \sum^{All\ TCs} \sum^{All\ units} WFactor_{unit,tc}$$
2. Calculate total regulation costs
$$RegulationCosts = \sum^{OverPeriod} \sum^{All\ regions} (P_{region,RAISEREG} * Enablement_{region,RAISEREG} + P_{region,LOWERREG} * Enablement_{region,LOWERREG})/12$$
3. Calculate settlement constant as
$$SettlementConstant = \frac{TARGETRATIO \times RegulationCosts}{WFactorSum}$$

The constant can be updated from time to time, ideally no more often than once each settlement period and preferably over a longer period to avoid instability, so it is known to participants in advance. Any update should be damped to iron out week-by-week variation. Thus, while the constant may be set to target in the long run some fraction of DSCP turnover relative to AGC enablement of, say, 10%, 50% or 100%, the outcome in any given settlement period may vary widely and should not be adjusted, as such variation could reflect real variation in technical outcomes and costs in the system. It is more important that DSCP prices be locally calculable than a particular DSCP dollar turnover relative to enablement be achieved precisely in any given settlement period. This is because the costs of the services in each settlement period will be inherently volatile so achieving a target ratio every settlement period has little merit.

There are variations on how '*SettlementConstant' in the above equations c*ould be set. These variations could focus on regulation enablement costs and DSCP costs incurred by the residual, rather than globally. This might be more easily implemented and more appropriate depending on other policy settings, such as how the costs of enablement are to be allocated.

To illustrate such an approach, consider the settlement outcomes for the settlements in each NEM region, charted in Figure 20. In this example we have targeted residual DSCP/FDP costs over all regions to be 50% of regulation enablement costs overall. We also consider in this figure the option of assigning all regulation enablement costs to the residuals in proportion to energy. Interestingly, over this short period this results in Queensland bearing most of the DSCP/FDP share of the residual costs. It seems it would be useful to examine more aggressive ratios and also to consider the scope for cost reductions if regulation-enabled units also receive DSCP/FDP payments. This is an exercise we will consider in our Final Report.

Figure 20: Settlement of Residuals in All Regions

There are broader variations possible. One approach is to implement an updated causer pays process and to extend it to be double-sided – a direct and literal implementation of DSCP. The other would be to recognise that a generalised implementation of FDP along the lines presented in this report would provide rewards and incentives for good performance without requiring external funding. One might then seek a simpler and perhaps more robust way to recover the cost of AGC regulation enablement. These are matters to be considered in our final report and, ultimately, by the AEMC and the industry.

B.4 Preliminary Results

Figure 21 below displays the total factor, total weighted factor and total revenue for three of the best performers from each region for the week starting on 8 May 2021, using the following parameters:

- Unit trajectory: target to target linear ramp
- Weight: Uniform enablement price (maximum of raise and lower regulation enablement price)
- Time Constants: 4sec, 35sec
- Gains: 1 for both (i.e., equal)
- *SettlementConstant*: calculated by setting total of DSCP allocated to the residual at 50% of the cost of enablement.

The *SettlementConstant* calculation is a variation of the method described in Section B.3.4. Be aware that this constant simply scales all prices and settlement amounts. The payments remain balanced and the relative performance of units and regional residuals remain unchanged.

The level of performance in this is determined by a unit's relative DSCP income/payments. Income implies "good performance" and payment implies "bad performance". It is dependent on unit size, so not necessarily a measure of how effective the unit's management is. We could normalise these measures by unit size as an alternative way to present performance.

In this example, Wivenhoe does well, assisted in Queensland by support from the QNI interconnector. The support is significant both physically and even more so financially, due the relatively high energy price weightings in Queensland.

Figure 21: Best Performers of Period by Region

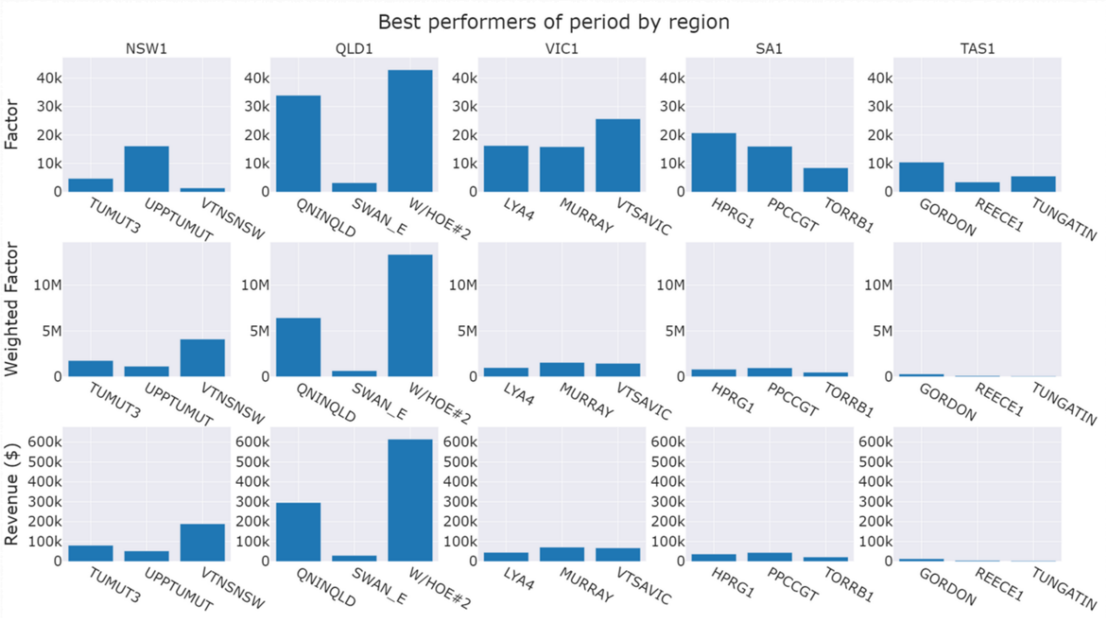
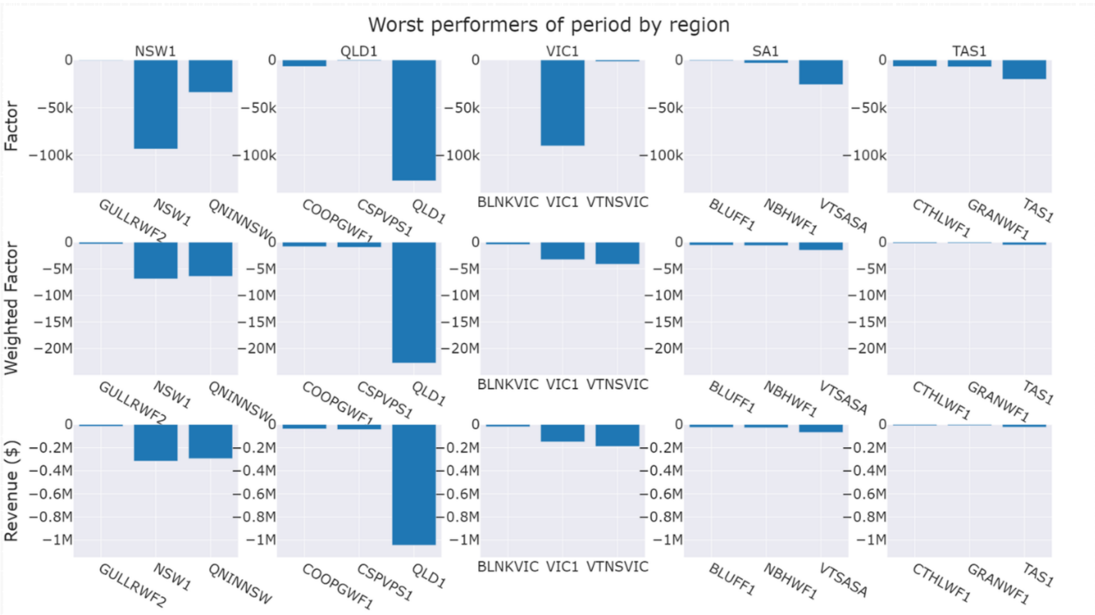


Figure 22 following shows the three worst performers in each region. In the three largest NEM Regions, unsurprisingly the regional loads show the highest negative performance, largely due to load forecast error. Some renewable plants also rank as relatively poor performers but not nearly as poor as the regional demands. Under DSCP as well as the existing Causer Pays, regional demand forecast errors generate the bulk of the need for FCAS and therefore end up paying for much of that service.

Figure 22: Worst Performers of Period by Region



B.5 DSCP Prices

Deviation prices can be a more enlightening way to view DSCP outcomes than through factors whose dimensions are not immediately clear.

The settlement formula as a function of deviation is given below :

$$Settlement_{unit,tc}=Deviation_{unit}\times f(-Hz,\ tc)\times Weight_{unit}\times SettlementConstant$$

The settlement per unit of deviation is essentially the deviation price and is given by

$$DeviationPrice_{region,\ tc}=f(-Hz,\ tc)\times Weight_{region}\times SettlementConstant$$

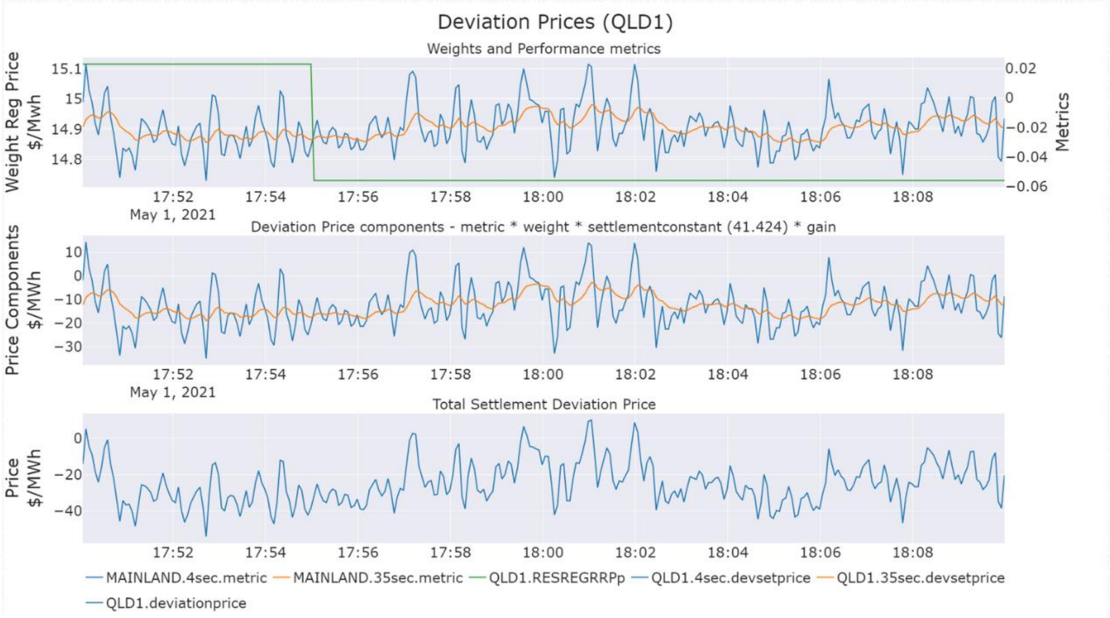
Note that there are alternative, equivalent, formulations that specifically include the measurement interval, dt, to convert MW measurements to energy rather than subsuming that value in *SettlementConstant*.

Since there are 5 regions and 2 suggested price components with different time constants there are a total of 10 different deviation prices for each instant, but only two for any given connection point.

Figure 24 following shows a May 2021 Queensland example of deviation prices plotted over a 20-minute period, so spanning 4 DIs.

- The top chart shows the 4 second and 35 second metrics (blue and red) and the weighting from the dispatch process (note the vertical axis limits on the left.
- The middle chart shoes the two metrics with the weighting applied (to get FTP components).
- The bottom chart shows the combined FTP with an equal weighting applied to both.

Figure 23: Example of Normal Deviation Prices



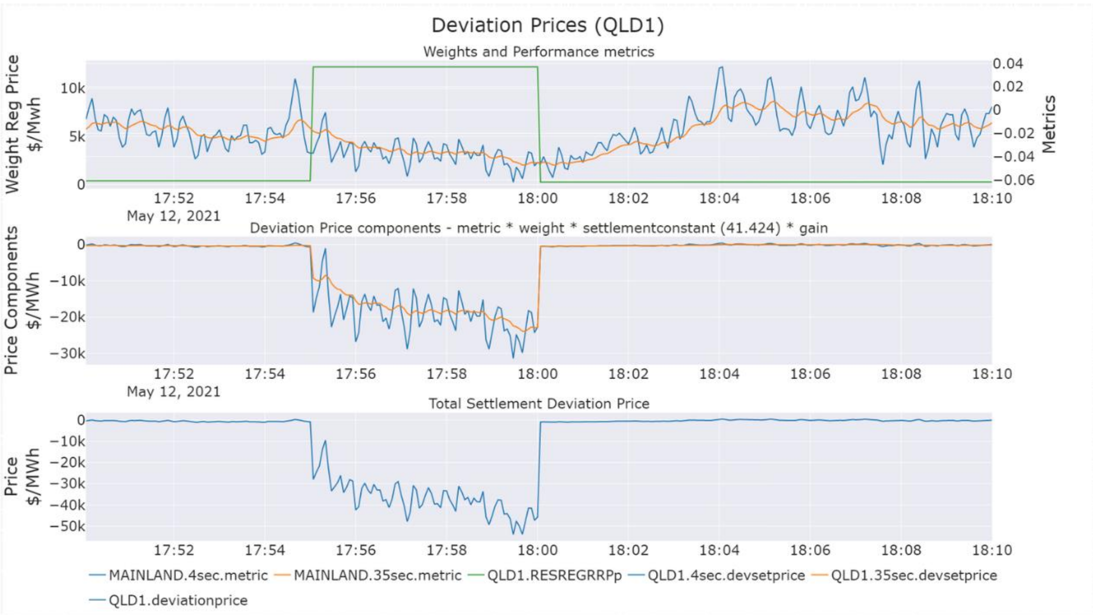
The rapid fluctuations are driven by the short time constant price component and promote a rapid response. The slow drift is largely the longer time constant price which compensates for units that are operating away from target to keep the frequency under control.

Note that the FDPs are mostly negative over this period. In this example, equal weightings were given to each price component. Closer study might indicate a different weighting could yield performance and costs better aligned to requirements. It is conceivable that the value soaked up by the occasional energy price spike would leave insufficient for more normal periods of operation. If this is so, a different weighting methodology could be considered.

The weighting process can result in extreme variations in FDP, tracking the dispatch market. For example, consider the example in Figure 24 below. Immediately evident is the heavy weighting from the spike in enablement prices in the second period. This translates to a spike in all FDPs in the second period; these FDPs dominate all those immediately adjacent.

Within the second DI, there is an initial negative offset which gradually increases over the interval, with shorter term fluctuations driven by the 4 second component. This is explained by the behaviour of frequency over this period, it starts out negative and gradually becomes more so, as shown in the top chart.

Figure 24: Example of Extreme Deviation Prices



This example highlights how critical the choice of weighting is. Under current causer pays, the variability of various prices in the energy and FCAS dispatch markets are ignored. However, if responses to FDP/DSCP are to be relied upon in any way, one needs confidence that participants will remain interested in performing when market volatility is high. This provides the basis for some form of weighting.