A DOUBLE-SIDED CAUSER PAYS IMPLEMENTATION OF FREQUENCY DEVIATION PRICING

An ARENA-Supported Project Sponsored by the Australian Energy Council

16 April 2021

INCEPTION REPORT

Intelligent Energy Systems

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1 Introduction

1.1 Project objective and inception report objectives

The objective of this AEC sponsored and ARENA supported project is to research and model the Double-Sided Causer Pays (DSCP) approach to controlling Primary Frequency Response (PFR) and potentially also to other related slow-moving services such as those for regulation. The project will support the evaluation of DSCP by policymakers relative to other primary frequency control options. Its role in the wider frequency control regime will also be considered.

This Inception Report will outline the tasks to be performed in detail, including the early identification of any possible issues with the proposed design and analysis work.

1.2 Project Governance

Details of project governance are provided in Appendix A.

1.3 Project Work Strands

There are three strands of work to be grouped into three project reports. As described in the IES/AEC contract, they are:

Control and Pricing Theory Report

To set out control and pricing theory, its application to DSCP and associated conclusions relevant to the design considerations for practical implementation of DSCP. The report will also address questions and objections raised regarding DSCP.

PFR Performance Analysis Report

To provide a comprehensive performance analysis of primary frequency response before and after synchronous generators were required to provide it, and to assess the likely effects or introducing a DSCP scheme. The initial models developed by IES will be refined to match the theory developed at (the previous) Stage R2, and tested against a wider dataset, using scenarios based on the Integrated System Plan, and further developed at Stage W1 (a knowledge sharing workshop), including a scenario with high penetration of renewables. The results will be analysed to determine whether the theoretical model needs further refinements, and they will also inform the overall viability of DSCP.

Project Summary and Conclusions Report

To take the findings of Stage R3 and summarise the recommended features of a DSCP implementation for PFR, their individual values and their justification (including costs and benefits), with a view to informing debate and providing a viable alternative once mandatory PFR expires in 2023. In addition, the report will touch on alternative solutions to frequency control and their advantages and disadvantages.

The way we propose to approach these work strands is outlined in the Sections 2, 3 and 4 of this Inception Report. The timing of the delivery of these reports is provided in Appendix A on project governance.

1.4 Project Workshops

We are also required to undertake two industry workshops during the project. According to the IES/AEC contract they are:

Interim Workshop on Control and Pricing Theory Report

To provide members, other interested industry participants (such as the AEMC) and ARENA with the findings from the initial two reports and allow discussion to inform the planning for subsequent reports, including the scenarios to be developed. The workshop will discuss the theory behind the DSCP proposal in the context of other possible solutions and engage with workshop attendees on perceived problems with the implementation of such a scheme. This will ensure that all issues are addressed before the detailed analysis is conducted. While the workshop will be led by IES, administrative arrangements will be made by the AEC.

Knowledge Sharing Workshop following Project Summary and Conclusions Report

To inform stakeholders and interested parties of the results of the study and provide them with the opportunity to ask questions and better understand the work which has been undertaken. The workshop will refresh the theory, step through the analysis undertaken and present the findings to attendees, noting that DSCP is but one of several possible solutions to primary frequency control. If questions cannot be answered immediately, they will be recorded and answers provided after the workshop. While the workshop will be led by IES, administrative arrangements will be made by the AEC.

The proposed timing of these workshops and suggestions for structuring them are outlined in Appendix A on project governance.

1.5 Current status and options for frequency control

The DSCP concept is being put forward in the context of significant changes underway in how frequency control in the National Electricity Market (NEM) is to be managed. Appendix D summarises the current status and options for development currently under consideration. This provides the context for where DSCP might fit in the universe of frequency control options.

The governance arrangements for overseeing and implementing these changes are complex. The Energy Security Board (ESB), the Australian Energy Market Commission (AEMC) and the Australian Energy Market Operator (AEMO) all have a role. Market participants also have a say on any changes proposed, so we also summarise the position of this project's principal sponsor, the Australian Energy Council (AEC).

Electricity markets overseas are also undergoing changes to accommodate the growing importance of renewables. The physical, market design and institutional arrangements differ but their approaches can be enlightening. In Appendix D we also review the frequency control arrangements in a US market (CAISO), Ireland, Scandinavia and New Zealand. Of these, Ireland appears most relevant to Australia in having to identify new services to deal with increasing renewables in a small, isolated market.

2 Control and Pricing Theory

This strand of work aims to put the DSCP concept on a firm theoretical and practical foundation. While the concept has intuitive appeal, there are many details of implementation that are best resolved through robust theory and practice. Also important is to demonstrate the basis for DSCP's efficiency, operational stability and consistency with related frequency control services.

This work is in two main parts. We aim first to develop the theoretical foundation, building on tried and tested frameworks such as linear quadratic control and its extension to so-called Gaussian control. The apparently novel aspect here is to recognise that there is a powerful pricing element to the theory, as there is with linear programming that drives the NEM dispatch engine. In this first part we will try to derive as many useful insights as possible from the theory and from running a series of "toy" illustrative examples, ranging from the trivial to examples broadly suggestive of the real system.

The second part will build on these results to answer, or at least inform, a range of design questions that would or could arise in practical implementation. An important example is how DSCP would interact with other frequency control services. Another is to deal with the possibility of network separation.

2.1 Control and Pricing Theory

This section will proceed systematically though the theoretical basis for frequency deviation pricing(FDP), of which DSCP is a specific implementation. The theory builds on well-established approaches to control, but emphasises the pricing element embedded in them, in much the same way as there is critical pricing information embedded in the linear programming approach to market scheduling in the NEM. This theory should allow potentially contentious design issues to be considered on a firm foundation.

Our approach will state the theory and explore the basis for it, but mainly use that theory to build up increasingly realistic models of an electricity system. Each step of the process will be supported with a "toy" system model and charted simulation results. To summarise, in this part we will do the following.

1. Introduce the linear quadratic regulator without system noise, with examples.
   - State assumptions clearly – important when comparing with current approach.
   - Some initial assumptions will be relaxed later.
   - Note the continuous and discrete variations.
2. Demonstrate how pricing information (deviation prices) can be extracted from the model.
   - This will be a theoretical exercise which will have to be operationalised for implementation (for example, because good data in a real system may not be available). Ways to do this will be addressed under Section 2.2.2.
3. Demonstrate how deviation prices contain all information needed for control.
   - Specifically, demonstrate how the pricing function would affect technologies ranging from different type of rotating plant to renewable plant and batteries, and how the cost of provision would flow through to prices.

- We will note the general absence of suitable metering on the demand-side and propose ways forward in Section 2.2.2.

4. Introduce system noise into the model.
5. Identify potential challenges when attempting to scale to a real system.
   - Incomplete information
   - Too many elements to handle.
6. Using the Kalman filter to estimate system state from limited local data.
7. Introduce Gaussian control; combine the linear quadratic regulator with state estimation.
8. Dynamic behaviour of system state and system price
   - Including demonstration of pricing synthetic inertia
9. Reducing the size and complexity of the dynamic pricing formula.
10. Key results from general theory, given system assumptions:
    - When noise is strictly Gaussian (as it appears to be for regulation), the theory gives an optimal controller which is linear and where the output states (e.g., frequency) are normally distributed over time.
    - When noise is non-Gaussian (e.g., with contingencies), the theory gives the best (and same) linear controller; however, there may be a better non-linear controller.
11. Relate the results so far to the current frequency control arrangements.
    - Note similarities, differences, and the scope for complementarity.

2.2 Moving to practical implementation

2.2.1 DSCP as a specific implementation for PFR

Show how DSCP as currently understood is a specific implementation of frequency deviation pricing for PFR, having the following elements:

- broadly “looks like” current causer pays and could be combined with it in some way.
- uses SCADA 4 second data for centralised calculation.
- accumulates 4 second 5-minute calculations into 5-minute factors for accumulation into a settlement calculation; and
- proposes a specific way to weight 5-minute values and price the service.

We will note this relationship at this stage but move on to derive other properties from the general theory.

2.2.2 Real world issues to address

We need to review some properties of the pricing formula to support the quantitative studies to carried out for the PFR and Performance Analysis studies and report (Section 3).

1. Interface with other frequency control services
   - Should services (with different time characteristics) and associated prices be kept strictly separate, or do they overlap physically and also with pricing?
   - Note that enablement services resolve some (but not all) major non-linearities such as upper operational bounds.

2. Scaling properties of the solution
    - Highlights whether pricing formula parameters could be constant over time if suitably weighted.
    - Determine whether pricing weightings are likely to be stable under different system conditions, including network separation.
    - Practical response when those conditions are not perfectly met.
3. Operation with a mandated requirement and with existing and possible new enablement markets
    - Can operate with a mandatory PFR requirement, although some elements of the mandate could be loosened.
    - Enablement is there for AEMO assurance and to ensure headroom. FDP is intended to incentivise actual operations and so is complementary.
    - Consider the economic issues around having FDP complementing enablement and a mandatory approach to PFR.
    - Consider the case where AGC controls are too complex to model in pricing directly.
4. Options for determining the frequency deviation price (or weightings) on 5-minute factors in the case of DSCP. Possible options include but are not limited to:
    - CSE/IES original method, where the cost of provision as estimated by DSCP is set to an estimated cost supply by thermal generators at each 5 minutes.
        - This method assumes that the marginal provider is a thermal unit and is not consistent with a medium to long term scenario.
    - Weight by energy or FCAS prices, noting the desirable properties of encouraging greater regional diversity of supply (even with enablement markets) and also promoting hedging of the service using energy market instruments. This approach describes how weighting might vary in different situations; one still needs a price sufficient to deliver the required frequency result efficiently.
    - A pragmatic, incremental approach.
    - A weighting which evolves in real time to keep frequency within required bounds.
5. Stability of the system as it evolves with more renewables and lower inertia.
    - Review history and potential for special cases, such as extended cloud events and solar eclipses
    - Review and model the impact on stability with synthetic inertia.
6. Stability of the system as it evolves with more batteries.
    - In the case of batteries, explore the theory when response speed becomes fast and cost of changing output near zero in the short term, focussing on impact on system stability.
    - Consider incentives for pricing batteries in the long term.
7. Impact of potential "rogue behaviour" – when a participant does not follow the price incentive to a significant degree.
    - explore the impact of "rogue behaviour" (i.e., behaviour that to some extent ignores the financial incentives) on stability and on individual margins.

  - Such behaviour could come from batteries responding too quickly and also from other causes.

8. Dealing with energy pricing discontinuities
   - If participants are to focus on real time operations, it is important that they do not see pricing discontinuities.
   - Such discontinuities would be present in most formulae which weight 5-minute factor calculations.
   - We will present an easily implemented causer pays calculation which removes this discontinuity.
   - We will also deal with what happens during a contingency event, including possible wealth transfers at such times.

2.2.3 Overview of role and design of a possible DSCP implementation

From the analysis of this work strand, we will set out a potential role for DSCP and some key aspects of its design This possible design would be subject to further analysis as in the following work strand.

3 PFR Performance and Analysis

This report will present quantitative work, using historical data when appropriate and when available, addressing three distinct topics:

- current PFR and related performance, as well as the scope for improvement;
- the impact on DSCP of potential SCADA metering errors, as well as identifying longer term metering alternatives; and
- using modelling studies to study how the system may perform under DSCP when under certain types of stress, and as the system evolves from 2021 to an expected much different system in 2031.

3.1 Recent and Current PFR Performance and Scope for Improvement

This analysis will use AEMO-published 4 second data to calculate DSCP measures, both normalised and unnormalized, to assess performance and changes in performance of NEM participants, mainly generators but also metered loads and residual loads. System-wide performance will also be assessed. The results will be presented in performance tables and charts in NEOpoint and made available through the project website. This study will have the following components:

- PFR performance prior to introduction of mandatory rule
- PFR performance under the mandatory rule
- a comparison of system-wide (frequency) and individual performance improvement of the mandatory rule relative to the period prior; and
- the scope for further improvement under DSCP.

3.2 Analysis of Impact on DSCP of Potential Metering Errors

3.2.1 SCADA Metering

SCADA metering at 4 second intervals (longer in Tasmania) is designed for real time monitoring and control but is also used for allocating the cost of regulation under the Regulation Causer Pays (RCP) procedure. SCADA metering is also proposed to monitor performance under a DSCP procedure supporting PFR. A more accurate, finer resolution method of performance measurement would be desirable but is not yet available in practical form.

In these studies, we will assess the nature and likely scale of possible errors from using SCADA metering for DSCP settlement. To do this we will:

- identify the potential sources of error.
- use 4-second frequency, generation and load data (where available) to estimate the sensitivity of the DSCP calculation to error; and
- assess the relevance of each form of error, and of potential errors overall.

In some cases, the assessment of DSCP factor error per unit of potential meter error (of a particular type) will be simple; in others some 4 second calculations need to be done on a representative set of generators/loads. Applying the known error performance of SCADA 4-second metering to each of the sensitivities above should complete the assessment for that form of error. We can then assess the overall impact of SCADA metering error on DSCP.

Potential sources of error to be examined will include:

- Scaling error
- Offset error.
- Time delay error
- Discretisation error
- Random error
- Outage error
- Other errors

3.2.2 Other metering options

We acknowledge that SCADA is not an ideal metering solution. In this section we will:

- Examine ways to improve metering for PFR and other forms of FCAS.
- outline an IES meter prototype development; and
- develop a metering implementation strategy should DSCP proceed.

3.3 Modelling and Testing of Specific Situations

Earlier stages of this project will develop the concepts and tools to support DSCP and analysis of its performance. In this stage of the work, we will study specific areas of potential concern in more detail.

3.3.1 Stability of potential battery responses

Grid scale and small scale-batteries embedded in the distribution network are expected to be a growing part of the NEM in future. Batteries can be operated to arbitrage high and low energy prices throughout the day, but they are also highly suitable for providing FCAS due to their ability to ramp quickly and sustain a change over a period of 10 minutes. Some large batteries such as Hornsdale already contribute various forms of FCAS under current market arrangements or special contracts.

The DSCP concept would support PFR with or without a specific enablement process. In either case, market rules or regulations could specify operational bounds such as ramping limits to attempt to eliminate any possible security risk. Such an approach would operate more smoothly if DSCP financial incentives align with the aim of secure and efficient operation.

While DSCP aims to promote such security and stability, some type of plant such as batteries might present a particular challenge to stability. The reasoning for this goes as follows.

- Within a 5-minute dispatch window, a battery is technically able to swing between large positive and negative powers very quickly, at sub-second speeds.
- Unless only a specific MW level is enabled, when frequency error changes sign, there is potential for a large and destabilising power swing in response.
- Even if theory suggests that promoting such instability would destroy financial margins, in practice imperfect knowledge and co-ordination could still lead to this unacceptable outcome.
- It follows that DSCP may need to be accompanied by a set of operational rules, at least in the case of rapid response plant such as batteries.

To study this, we propose to build or add to our frequency deviation pricing demonstration model to include a battery-like option. This will be characterised by an ability to:

- ramp up and down rapidly and at low cost nearly always (when away from lower and upper charging limits); and
- sustain that change at low cost for a period of up to 10 minutes.

If we make costs very small, we can look to the structure of the optimal control strategy. If the gain for battery control with respect to frequency error is very large, there may be a practical problem requiring some mitigating rule if DSCP we to be used without enablement. However, it may also turn out that the optimal gain on battery control is determined by some other factor than battery ramping ability, such as system inertia. In this case some co-ordinating mechanism may still be desirable, but more as a guide than as a hard control.

Some other variations could be tried. For example, if synthetic inertia became a viable product, stability could be enhanced and battery response potentially of less concern.

3.3.2 Stability under non-optimal behaviour

The theory set out in this project assumes initially that participants act rationally to maximise operating margins. However, what if a significant participant or group of participants fails to act rationally, or has insufficient information to do so? These studies will address this possibility. In essence, they will be somewhat like the battery studies, but the response possibilities covered are longer than sub-second and may follow no pattern. We note that retention of enablement for wideband PFR and regulation and mandatory provision of PFR capability may make this issue moot.

The series of studies will assume that a particular participant varies her optimal strategy in various ways. We could choose, say, 3 scenarios to study. We then examine the impact on stability and margins of this behaviour.

We could then expand this study to include a larger block of plant acting in a similar way.

3.3.3 Studies with an indicative system model circa 2021

The analysis and demonstration of how DSCP works earlier in this project uses “toy” data sets to illustrate specific elements of DSCP. For this set of studies, we will build a system with set of assets representative of the current system. We will not model individual units or power stations, but groups of units and stations representative of the current plant mix, inertia level and FCAS performance levels.

From these studies we will report on:

- the DSCP settings likely to be required to achieve efficiency and stability;
- likely margins earned or costs incurred by classes of participants over some period such as a year; and
- the likely interaction with related FCAS such as regulation and contingency.

3.3.4 Studies with an indicative system model circa 2031

We wish to study how DSCP is likely to perform and how settings might change a decade from now (2031) when the following trends are likely to be evident:

- lower system inertia due to the retirement of high inertia rotating plant.

- greater penetration of low cost, fast-moving grid-scale and small-scale batteries.
- greater penetration of renewables with associated variability and uncertainty in output.
- structural reforms to the market as proposed in the ESB's 2025 plan; and
- a likely larger system with some new, green-type industries.

We will vary the model parameters to match as nearly as possible projections from AEMO and ESB. We will then report on:

- the same items as in the 2021 study
- a comparative analysis of the two cases

3.3.5 Conclusions from quantitative studies

From these studies we aim to answer the following questions.

- How has mandatory PFR improved performance and what performance improvements might be possible under DSCP? As mandatory PFR has improved frequency control to be operating well within the frequency standard, any improvement from DSCP is most likely to be in the form of improved efficiency leading to lower costs.
- What order of errors is possible from the use of SCADA metering for DSCP settlement? How do those errors compare with those where SCADA metering is used for other services, such as paying for regulation? Are any such errors acceptable, at least in an initial phase, to achieve the potential benefits of DSCP? What are the longer-term metering options for DSCP and possibly related services?
- How would DSCP be likely to perform if implemented now and in another 10 years when the system has evolved? Specifically, we would expect the providers of PFR and other forms of FCAS as well as consumer responses to change significantly over that time. In this assessment we will take account of issues and options available to manage potentially destabilising behaviour arising from various sources.

4 Project Summary Report

This chapter will summarise and draw conclusions from the project work. Specifically, it will propose a specific DSCP design and variations for consideration. It will also propose an implementation strategy.

4.1 From the inception work on current status and options

Summarise principal conclusions.

4.2 From the control theory work

Summarise principal conclusions.

4.3 From the PFR performance and analysis work

Summarise principal conclusions.

4.4 Proposed DSCP design and variations for industry consideration

There are likely to be key design decisions that would best be resolved through AEMC or other formal processes of industry consultation. So, we will aim to propose a core DSCP design and to list the variations that might be considered, with our own recommendations and reasons where appropriate.

4.5 Project Conclusions and Recommendations

To be determined.

Appendix A Project Governance

A.1 Contracting

The principal contract for the is project is between AEC and ARENA. AEC has contracted IES to perform the research work though sub-contract dated 19 March 2020.

A.2 Steering Committee

The objective of the Steering Committee is to oversee the project from the perspective of the sponsors and the contract obligations to ARENA.

The members of Steering Committee together with their organisation, position and contact details are set out in the table below.

Table 1 : Steering Committee Members and Details

Name	Position	Organisation	Telephone	Email
Ben Skinner	GM Policy and Research	Australian Energy Council (AEC)	0417 118 479	ben.skinner@energycouncil.com.au
Hugh Bannister	CEO and Project Lead	Intelligent Energy Systems (IES)	0411 408 086	hbannister@iesys.com
Joel Gilmore	Regulatory Affairs Manager	Infigen Energy (Infigen)	0411 267 044	joel.gilmore@infigenenergy.com
Henry Gorniak	Market & Power System Specialist	CS Energy (CSE)	0418 380 432	hgorniak@csenergy.com.au

The Steering Committee will meet by video fortnightly or as determined by the chairman from time to time. The chairman will prepare an agenda after consultation with Committee members and a draft record of the meeting will be prepared immediately after each meeting, circulated for comment on accuracy, then finalised and filed.

A.3 IES Project Team

The project team from IES will consist of the following people, who are named in the AEC/IES sub-contract. Summary CVs are provided in Appendix C.

Table 2: Project Team Members and Details

Name	Position	Organisation	Telephone	Email
Hugh Bannister	Project Leader	IES	0411 408 086	hbannister@iesys.com
Jabez Wilson	Research Engineer	IES	0416 371 806	jwilson@iesys.com

The project team members will maintain records of the time worked on the project and IES will provide such records to AEC if requested.

A.4 Public Consultation

The project contract requires public consultation at key points as the project progresses.

- on substantial completion of the theoretical work; and
- on completion of the Final Report

Consultation will be in two forms.

- Summary 1-1.5-hour presentations including Q&A sessions, conducted online.
- For those interested in more technical detail, we could run two half-day sessions to present the theoretical work and, later, the results of the quantitative analysis. Further consideration closer to the time might warrant a modification to this latter approach.

AEC will organise and manage the workshops, but the project team will be the main presenters. Ample opportunity will be given for participant feedback.

On completion of the Theoretical Report and interim workshop and the Performance and Analysis report, written submissions from participants will be invited and summarised in the Project Summary and Conclusions Report.

A.5 Project Schedule

Table 3: Project Schedule

Identifier	Stage	Indicative Timing
Px	Progress Meetings	Fortnightly
P1	Planning Meeting	March 2021
R1	Inception Report	16 April 2021
R2	Control and Pricing Theory Report	14 May 2021 (amended)
W1	Interim Workshop	28 May 2021 (amended)
R3	PFR Performance Analysis Report	30 July 2021
R4	Project Summary & Conclusions Report	30 September 2021
W2	Knowledge Sharing Workshop	30 September 2021

A.6 Project Website

As part of the public consultation and information dissemination process, the project will establish a project website. The main portal will be through the AEC website. AEC will develop and maintain the main project website. However, it may point to pages on the IES website for more technical information such as live plots, simulations and data. A summary of the data proposed to be provided is at Appendix B.

The main project website will contain:

- a description of the project.
- final project reports, as completed and signed off.
- Information and registration for workshops.
- any spin-off articles by AEC; and
- a link to IES pages where more data will be accessible – see Appendix B for details.

A.7 Project Risk Management Plan

Good practice and ARENA require us to establish and maintain a risk management plan. Further, ARENA requires the plan to be audited by a suitably independent party. This plan will be reviewed by CS Energy and managed by the Steering Committee.

Appendix B Project Data Availability

The following data items will be established on a dedicated project section on IES's NEOpoint platform, accessible from the AEC's website project page. Some 4-second data may only be stored for selected intervals for review as longer-term results are accumulated and stored in 5-minute records.

B.1 4-Second Data

1. Participant generation, regional demand and interconnection flow
2. AEMO-measured frequency, time error and FI
3. Deviations and DSCP calculations based on the above
4. Various PFR performance measures and comparisons based on the above
5. Results of meter error calculations at the 4 second level

B.2 5-Minute Data

1. Relevant published market data such as market energy prices, FCAS enablement market prices, etc.
2. Accumulated DSCP factors for scheduled generators, semi-scheduled generators, SCADA-metered loads, interconnectors and residual demand.
3. Various DSCP performance measures and comparisons based on the above
4. Summary results of meter error calculations at the 5-minute level.

B.3 Model Data

Modelling data will generally be small scale, indicative and stored in spreadsheets for ease of dissemination. Generally, there will be one or more spreadsheets of data for each stage of the modelling carried out in the project although many will be similar and possibly identical. For example, to model:

1. the simplest case
2. a more complex case (3 units and variable load with inertia, PFR and direct control)
3. a system driven by prices.
4. some practical implementation issues.
5. battery performance (potential for rapid/unstable response)
6. bad behaviour
7. a system structured similarly to the NEM in 2021.
8. a system structured similarly to the NEM in 2031.

Appendix C Project Team Member Profiles

C.1 Hugh Bannister

Hugh is the founder, Chairman and CEO of IES.

With over 35 years of experience advising on energy sector reform and managing IES, Hugh advises government, industry and regulatory bodies on electricity markets and macro energy policy in Australia and ASEAN countries. Hugh conceptualised, developed and commercialised the analytical tools that IES uses internally and sells to its clients.

Hugh has particular expertise in development and implementation of energy policy, energy market design and industry reform, and application of mathematical modelling to a range of complex technical problems.

Hugh was heavily involved in debates, discussions and technical and economic analysis that led to Australia's current electricity market design. He has subsequently advised on various aspects of the market's evolution, in particular the development and implementation of Australia's ancillary service markets. For the past decade or so he has moved more into project management and oversight for both Australian and international projects but is still active in technical and economic aspects of market design. Hugh will be the project manager and technical lead for this project.

C.2 Jabez Wilson

Jabez Wilson is a research analyst who combines his knowledge of engineering disciplines and mathematics to deliver project results and objectives. He joined IES in 2019 and has been heavily involved in IES' research projects specifically in novel market design.
His assignments include:

- Research and development into IES' deviation pricing project. The project aims to design a regime where producers and consumers pay/get paid for every deviation they cause/ correct.
- Develop and investigate a market mechanism to pay for primary frequency response that would incentivize good frequency, as part of a project commissioned by CS Energy.
- Regular analysis of key trends and events in the energy market.
- Certification of the changes made to AEMO's settlements and billing calculation engine against the rules. The changes were developed to facilitate 5MS and Global Settlement in the NEM.
- Project lead in IES' custom dashboards project, where he oversaw the implementation of custom web dashboards commissioned by our clients to view public market data as well as their own private data.
- Research into IES' Energy Optimiser project, the aim of the project is to develop an optimisation model to allow residential and business customers to make informed decisions on which solar PV and/or battery system to install such that costs are minimised.

Before working at IES he was working in a research firm aiding in the analysis and design of optical lenses. He was tasked with the development of systems to aid in the analysis and acquisition of optical data.

Appendix D Current Status of Frequency Control

D.1 Overview of Frequency Control[1]

The effective control of frequency in a power system is important because most large grid-connected elements (generation, load, transmission, and distribution) are standardised to operate at a nominal system frequency (in the NEM this is 50Hz). Significant deviations from this nominal frequency will cause damage to the grid connected elements.

Frequency is dependent on the balance of supply and consumption of energy; excess supply relative to consumption will cause an increase in frequency from the nominal system frequency and vice versa. Frequency can be maintained within operational limits by closely monitoring and maintaining the supply-consumption balance by a centralised operator with high visibility, or by some other centrally managed mechanism.

Maintaining sufficient levels of rotational inertia and primary frequency response is also required to maintain a secure power system. Higher rotational inertia reduces rate of change of frequency (RoCoF) which will slow the change of frequency after a contingency event. This is useful in giving other slower acting resources time to respond to the event. Primary frequency response (historically in the form of governor response from rotating plant) plays a similar role by adjusting generation according to locally measured frequency. For example, in the case of a steam turbine, if frequency is above nominal steam to the turbine is reduced and vice versa. This assists in regulating frequency during normal operation as well as reacting to a contingency event faster than other resources. Semi-scheduled (renewable) plant and batteries can be controlled in a similar manner, subject to some technical and economic limitations.

Most large operators of grid connected elements will implement emergency frequency control schemes, which usually involve switching off or disconnecting elements when the frequency is above or below a certain threshold. This goes a long way in correcting any sudden shortfalls of supply or consumption. Hence, this provides a backstop to significant frequency deterioration after a contingency event.

D.2 Current NEM approach to Frequency Control

Under the National Energy Law AEMO has a statutory responsibility to maintain a secure and reliable power system. Under the National Energy Rules this involves (but is not limited to):

- ensuring that system parameters like frequency remains within operational limits, and
- ensuring that the system can recover after a significant contingency event (unexpected loss of load or generation) by dispatching extra generation or load to cover the shortfall.

AEMO does this by procuring energy reserves through the frequency control ancillary services markets. There are 2 types of reserves: regulation and contingency reserves. Regulation reserves are connected to AEMO's automated generation control (AGC) systems; the AGC measures frequency and will increase or decrease generation (maintaining the balance) by orchestrating multiple units' reserves procured through the regulation FCAS market. Regulation reserves can be

[1] Most of the detail can be found in the explanatory sections of the Frequency Control Frameworks Review: https://www.aemc.gov.au/markets-reviews-advice/frequency-control-frameworks-review

of either raise (increase generation or decrease load) or lower (decrease generation or increase load). Contingency reserves are not centrally controlled but will measure frequency locally and will increase or decrease generation if a contingency[2] event is detected, usually because of a trip of a grid connected element. Contingency reserves are also of raise or lower types.

AEMO recovers the cost of procuring these reserves from market participants. The cost of raise contingency reserves are recovered from market generators and the cost of lower contingency reserves are recovered from market loads. The cost of regulation reserves is based on the regulation causer pays process, i.e., those participants that caused a higher need for regulation reserves will pay a higher portion of the costs. AEMO will calculate monthly market participant factors (MPF) that indicate a participant's share of regulation cost recovery, the higher the factor the higher the participant caused the need for regulation.

Inertia and PFR are not actively procured by AEMO but are required for maintaining a secure and reliable power system. Historically these services were provided for free by synchronous generation and their mechanical governors. Due to emergence of electronic governors, the level of PFR declined significantly in the NEM, especially after 2015, leading to poor frequency performance. This has been corrected by a mandatory rule for PFR capability but is subject to a sunset clause.

D.2.1 AEMO Work Program[3]

The electricity grid is rapidly transitioning from a system saturated with centralised large synchronous generation to one with small but more geographically dispersed inverter-based generation. AEMO has identified that current frequency control practices are no longer fit for purpose in a decentralised power system. AEMO has undertaken a work program to identify and rectify the issues with its current frequency control framework. The work is divided into 5 work streams as detailed in the following table.

Table 4: AEMO Work Program

Workstream	Outcome	Current Status
Primary Frequency Response	Implement broad-based primary frequency control	The AEMC has introduced a rule proposed by AEMO to mandate the provision of PFR (narrow band response) from all scheduled and semi-scheduled generation. This has led to a significant improvement in frequency performance under normal operation. However, this rule change comes with an end date at which time an approach that incentivises PFR, as opposed to mandating it, is to be implemented.

[2] A contingency event is detected when frequency exits the normal operation band (49.85Hz – 50.15Hz)
[3] Frequency control work plan : https://aemo.com.au/-/media/files/electricity/nem/system-operations/ancillary-services/frequency-control-work-plan/external-frequency-control-work-plan.pdf?la=en
Frequency control work plan update : https://aemo.com.au/-/media/files/electricity/nem/system-operations/ancillary-services/frequency-control-work-plan/frequency-control-work-plan-update-march-2021.pdf?la=en

Workstream	Outcome	Current Status
		AEMO has provided briefings and interim advice to the AEMC on the PFR incentivisation feasibility report which is to be published in June
Inertia/ RoCoF/ EFCS	Extended existing provisions to cover expected operating conditions for system security	AEMO has investigated the impacts of DER on Under frequency load shedding (UFLS) in SA, work is ongoing for the remaining regions.
Fast Frequency Response	Efficient procurement of frequency related services	AEMO has provided advice to the AEMC and the AEMC has published the FFR implementation options to its website. More work is to come after the AEMC has reached a final determination.
Frequency Control Ancillary Services	Adapting existing Contingency and Regulation FCAS services for current and emerging operating conditions	AEMO is conducting reviews of its MASS and constraint formulations to assess whether there is need for modification to accommodate the changing power system.
AEMO frequency management tools	Ability to model, plan, and operate the power system under expected and plausible operating conditions	AEMO has conducted work to improve its modelling capabilities to plan for the changing power system characteristics and behaviours.

D.2.2 AEMC Options[4]

In March 2020 the AEMC determined a rule proposed by AEMO to mandate the provision of narrow-band response[5] from all scheduled and semi-scheduled generation. In its final report the Commission noted that it would be preferable to introduce alternative or complementary arrangements that incentivise and reward the provision of PFR. As a result, the new rule has a sunset clause that removes the mandatory requirement on 4 June 2023. It is expected that by that time, a market system for incentivising PFR will be researched and implemented in the NEM.

The AEMC has recently published a directions paper on two frequency control rule change proposals. The first pertains to procuring FFR reserves: either as a new market ancillary service or by reconfiguring current arrangements to procure FFR through existing service classifications. The

[4] The material in this section is sourced from:
Frequency Control Frameworks Review: https://www.aemc.gov.au/markets-reviews-advice/frequency-control-frameworks-review
System services rule changes : https://www.aemc.gov.au/sites/default/files/2020-07/System%20services%20rule%20changes%20-%20Consultation%20paper%20%E2%80%93%20%202%20July%202020.pdf
Frequency control rule changes (mostly this): https://www.aemc.gov.au/sites/default/files/2020-12/Frequency%20control%20rule%20changes%20-%20Directions%20paper%20-%20December%202020.pdf

[5] Narrow band, as opposed to wide band response is the adjustment of generation to small deviations in frequency. Enabling narrow-band response across the NEM will lead to very tightly controlled frequency.

second proposal relates to permanent PFR arrangements as opposed to the mandatory arrangement currently in place. The AEMC has put forward 3 possible options for future arrangements:

- maintain the existing mandatory PFR arrangements with improved PFR pricing;;
- revise the Mandatory PFR arrangement by widening the frequency response dead band and develop new FCAS arrangements for the provision of PFR during normal operation; or
- remove the Mandatory PFR arrangement and replace it with alternative market arrangements to procure PFR during normal operation.

The AEMC's initial view is that option 2 is the preferred pathway.

D.2.3 ESB 2021 Approach[6]

The ESB is tasked with bringing out significant reforms as part of an energy market redesign. In the latest directions paper, they have identified 4 reform areas to pursue as part of this redesign. The areas are:

- Resource adequacy mechanisms and aging thermal transmission – Ensuring the right mix of resources is available through the transition.
- Essential system services and scheduling and ahead mechanisms – Ensuring those resources and services required to manage the complexity of the power system are available.
- Demand side participation – Progressively unlock the potential of consumers to compete in the wholesale market.
- Transmission and access – Providing arrangements for early implementation of renewable energy zones, and longer-term arrangements to ensure efficient use of the national network.

As part of the system services area, the ESB has prioritised the following in the short term:

- The need to refine frequency control arrangements and to address the potential need for enhanced arrangements for primary frequency control and a new market for fast frequency response.
- The need to procure system strength in a structured manner.
- The potential need for a new operating reserve or ramping service.

The valuation and procuring of inertia are considered by the ESB as a long-term goal. As many stakeholders have noted that valuing and procuring missing system services (e.g., inertia) is a priority that cannot wait till 2025, The ESB will consider assessing the value of procuring inertia under structured arrangements if required.

The ESB intends to use the AEMC rule change process to accelerate this agenda as other stakeholders have already proposed related rule changes (See above).

[6] Material in this the section is sourced from The ESB's Post-2025 Market Design directions paper : https://energyministers.gov.au/sites/prod.energycouncil/files/publications/documents/P2025%20Market%20Design%20Directions%20Paper.pdf

D.2.4 AEC position[7]

The AEC considers that mandatory narrow-band PFR is inconsistent with the valuation of "missing markets" philosophy and distorts existing markets and incentives. AEMO desires that all existing frequency control capability be made available to protect the system from extreme non-credible contingency events (e.g., 25 Aug 2018). The AEC believes this objective can be accomplished with mandatory wide-band PFR and a market arrangement to procure narrow-band PFR.

AEC argues that the current data shows that only a few units enabling narrow-band PFR will result in a more favourable frequency performance as stated by AEMO. This is highly conducive to a competitive market arrangement – only a small number of providers are needed to deliver strong performance. As the performance was largely due to tightening the dead bands of the ageing thermal fleet, there is a need to create a new value stream to ensure investment in adequate PFR replaces the ones that withdraw from the market.

AEC has recognised the value of exploring Double Sided Causer Pays in detail as one option that may be consistent with its preferred approach. It has sponsored this ARENA research project to that end.

AEC has also recommended that the Reliability Panel review the FOS to determine whether it is still relevant to the current power system as it is clearly inconsistent with AEMO's views on frequency performance.

D.3 Some Examples of International Practice

D.3.1 CAISO – USA

The California Independent System Operator (CAISO) maintains reliability on one of the largest and most modern power grids in the world. CAISO operates under rules set out in a Federal Energy Regulatory Commission approved tariff.[8] The tariff includes four Ancillary Services (AS)

- Regulating up and Regulating down,
- Operating Reserve consisting of
    - Spinning Reserve,
    - Non-Spinning Reserve, and
- Voltage Support

Regulating and Operating Reserve AS can be self-provided by the Scheduling Coordinators (SC). Credits are provided to SCs who provide more than their obligation. Any Ancillary Services not self-provided will be procured by the CAISO in the Day-Ahead Market (DAM) and Real-Time Market (RTM). The CAISO certifies resources for the provision of AS. To be eligible, a resource must be capable of providing 0.5 MW or more of regulation[9] on a continuous basis for a minimum of 60 minutes in the DAM or 30 minutes in the RTM. Resources must respond automatically to signals from CAISO without operator intervention. Payments for services can be rescinded if the resource

[7] Material in this section is sourced from an AEC rule change submission to the AEMC: https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0256_erc0296_-_aec_-_20210204.pdf

[8] The tariff and appendices are available on http://www.caiso.com/rules/Pages/Regulatory/Default.aspx. Accessed on 13 April 2021.

[9] Lower capacity is permitted if the resource is part of an aggregation or if it is a storage resource with 0.1 MW capacity or greater.

is off regulation or off Automatic Generation Control. Costs are recovered from SC according to their obligations and hourly price for the service. For regulation, the obligation is based on the SC's proportion of the metered demand for that hour.

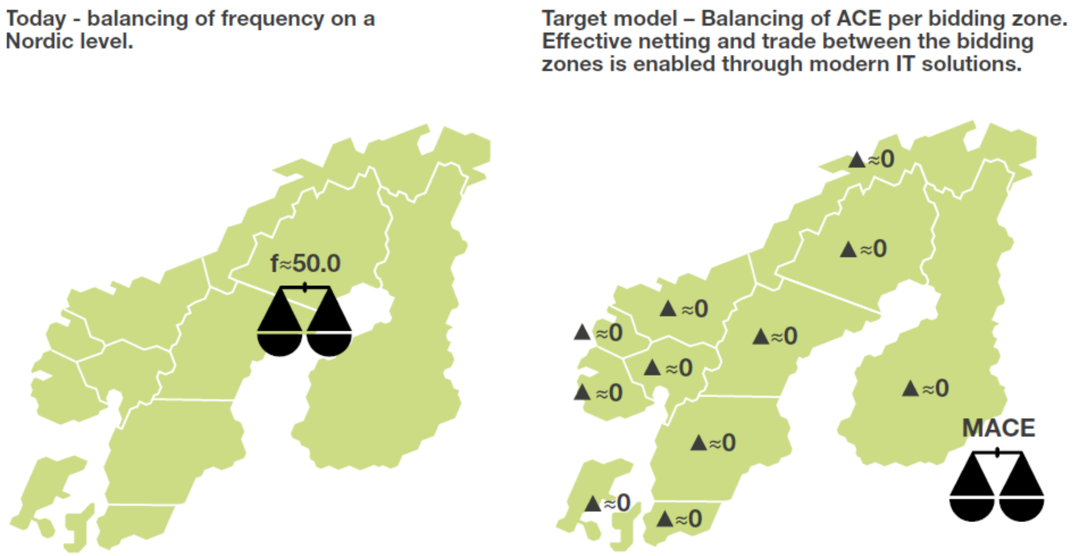
Ancillary Services can be provided from interconnected Balancing Authority Areas (BAA) through Interties but only in the Integrated Forward Market (IFM) and RTM. The RTM is a spot market conducted by the CAISO for the purpose of Unit Commitment, Ancillary Service procurement, Congestion Management and Energy procurement based on Supply Bids and Forecast of Demand. The CAISO uses Security Constrained Unit Commitment and Security Constrained Economic Dispatch in the Real-Time. It includes the Hour-Ahead Scheduling Process, Fifteen-Minute Market, Short-Term Unit Commitment and the Real-Time Dispatch.

D.3.2 Nordic Market - Europe

The Nordic market operates in Norway, Denmark, Sweden and Finland. The Transmission System Operators (TSOs) of these countries cooperate to manage the system. Bids are provided for the day-ahead market and imbalances are managed in the intraday market. Balancing Service Providers are qualified and contracted by their respective connecting TSO. The TSOs then enter into agreements to manage the Nordic system. It is expected that there will be periods when system stability is at risk due to the reduction of the share of generation from both hydro and nuclear generators is reduced. The system operator currently procures sufficient primary reserves either through required settings on generation units, or through a national market. It has not been required so far to procure inertia services explicitly. [10]

A development worthy of note is the move from balancing the entire Nordic market based on Area Control Error (ACE) to balancing of each bidding area based on Modern ACE (MACE), refer Figure 1: Move to Modern Area Control Error MACE.

Figure 1: Move to Modern Area Control Error MACE



[10] System operations and market development plan 2017-2021, Executive Summary, Statnett. A link to the document is available on https://www.statnett.no/en/for-stakeholders-in-the-power-industry/systems-operations-and-market-development/system-operations-and-market-development-plan/ accessed on 12 April 2021.

Source: System operations and market development plan 2017-2021, Executive Summary, Statnett[11]

Another development is the move from (locally controlled so called) manual Frequency Restoration Reserve (mFRR) to an Automatic FRR or aFRR. The first step is the establishment of a capacity aFRR market followed by an aFRR energy activation market. Gate closure for submitting aFRR bids by BSPs (in steps of 1 MW with a minimum of 1 MW) is 2000 hrs, 2 days before the date of provision. Settlement of aFRR procured capacity is on a pay-as-bid basis with an ambition to go to marginal pricing when the aFRR energy market is established.[12]

D.3.3 Ireland - Europe

A single electricity market operates across the Republic of Ireland and Northern Ireland. The system operators in Ireland began a program "Delivering a Secure, Sustainable Electricity System" (DS3) to facilitate achieving a high renewables penetration target. The EirGrid Group website credits DS3 with allowing the share of renewables to be increased from 50% to 65% with a target of 75% in the near future.[13] Schedules for 14 DS3 system services have been developed including:[14]

- Synchronous Inertial Response (SIR) to deliver (Stored kinetic energy)*(SIR Factor – 15);,
- Fast Frequency Response (FFR) to deliver MW between 0.15 and 10 seconds;
- Primary Operating Reserve (POR) to deliver MW 5 and 15 seconds and
- Secondary Operating Reserve (SOR) to deliver MW between 15 and 90 seconds.

Figure 2 provides a categorisation of the 14 services from the perspective of performance monitoring.

Figure 2: Categorisation of the 14 DS3 System Services for Performance Monitoring

Source: DS3 System Services Protocol – Regulated Arrangements, 1May 2019, Version 2.0

The rules allow wind and solar generators to participate in some services (such as FFR, POR and SOR) provided sufficient headroom is provisioned. Storage is also eligible subject to recharge limitations and a requirement to provide a real-time signal confirming its remaining charge available. Responses for these services are based on Reserve Triggers and not on Rate of Change of Frequency (RoCoF).

[11] Ibid.
[12] Explanatory document to Energinet, Fingrid, Statnett and Svenska kraftnät proposal in accordance with Article 33(1) and Article 38(1) of the Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing, ENSTO-E. https://nordicbalancingmodel.net/wp-content/uploads/2019/04/Explanatory-document-to-proposal-article-33-and-38-EBGL.pdf. Accessed on 12 April 2021.
[13] DS3 program on the EirGRID website https://www.eirgridgroup.com/how-the-grid-works/ds3-programme/ Accessed on 13 April 2021.
[14] Refer to DS3 System Services Protocol – Regulated Arrangements, 1May 2019, Version 2.0

The services are remunerated according to the equation below. The 'Scaling Factor' accounts for the accuracy of the unit's forecast (availability) and its response to an incident.

Trading Period Payment = Available Volume × Payment Rate × Scaling Factor × Trading Period Duration

Source: DS3 System Services Protocol – Regulated Arrangements, 1May 2019, Version 2.0

D.3.4 New Zealand

New Zealand's system operator, Transpower, currently procures three frequency-based ancillary services listed below:[15]

- Frequency Keeping involves two services. Costs are recovered from consumers based on their share of energy consumption.
    - Multiple Frequency Keeping (MFK) is provided by one or multiple generators capable of varying their output rapidly in response to instructions from the system operator. Providers are compensated through a fixed hourly availability fee plus variable costs through constrained on or off payments to compensate for any loss of revenue resulting from following instructions; and
    - Back-up Single Frequency Keeping is procured in case the central MFK system is unavailable. Contracted providers capable of detecting frequency and responding autonomously are compensated on a monthly availability basis.
- Instantaneous Reserve comes into automatic operation in the event of an unscheduled failure of a large generating unit or the inter-island HVDC link. The amount of instantaneous reserve to be procured for each trading period is calculated by the Reserve Management Tool. Costs are recovered on an island basis from generators with greater than 60 MW capacity and the HVDC link owner (Transpower) based on their share of energy injected into the system or transferred across the link.
- Over-frequency Reserve is provided by generating units that can be armed when needed and can quickly disconnect in the case of failure of a large industrial load or the HVDC link. The service is procured on either a monthly availability fee basis or a single event basis for specified generating units. Costs are recovered from the HVDC owner Transpower.

Procurement is performed by entering into standard contracts with generators, distributors, large load providers and demand aggregators primarily through a closed tender process conducted between August and November. New providers are required to demonstrate their capability through testing. Some services require regular testing during the life of the contract.

For the first two services, contracted providers submit offers and are dispatched through the half-hourly market. Pricing and settlement are performed by the Clearing Manager. The last service is procured and paid on either a fixed price or fixed quantity basis.

[15] Transpower's website https://www.transpower.co.nz/system-operator/electricity-market/ancillary-services-overview accessed on 8 April 2021.