Market mechanisms for frequency control

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***Abstract*— Australia and other energy markets are facing issues with the integration of large scale variable renewable energy (VRE) generation. Frequency control is an issue that is affected by reducing inertia and fewer providers of frequency control ancillary services (FCAS).**

In market environments, it is important to signal the need for appropriate FCAS resources and encourage innovation. Using pre-defined FCAS categories (such a 6s or 30s response times) is not flexible enough to adapt to increasing levels of VRE and associated reductions in inertia. Increasing levels of VRE exacerbate the frequency control problem if these inflexible categories are retained.

The authors believe that markets need technology agnostic standards that specify the required outputs – such as a frequency standard – rather than mandated Grid Code technical requirements or pseudo standards that define input variables such as inertia.

Market solutions are preferred as they align power system standards, system operations and economic incentives. Appropriate adjustment of standards and a redesign of the frequency control ancillary service (FCAS) markets, including economic incentives, would lead to improved power system security, reliability and more efficient outcomes.

This paper illustrates a market-based method of meeting a clearly articulated frequency standard. Our proposed market based approach would signal appropriate investment, encourage innovation and facilitate higher levels of variable renewable energy than would otherwise be possible in markets, which were originally designed for power systems with materially different characteristics.

Keywords - Variable Renewable Energy; frequency control; ancillary services; reserves; co-optimization; energy markets; governor systems; primary control; secondary control; automatic generator control.

I. INTRODUCTION

Increasing levels of inverter-based generation are causing the overall inertia in power systems to be reduced. Importantly, in some parts of the network with high densities of variable renewable energy (wind and solar), the inertia of the subsystem can fall to very low values.

As the inertia reduces, frequency control becomes more challenging as there is less time available to address imbalances in supply and demand [1]. Furthermore, frequency control services in some markets are procured using rigidly defined categories of services split into discrete timeframes where these service categories are based on historical inertia levels. With increasing levels of Variable Renewable Energy (VRE) penetration, there is now a need to review these frequency control ancillary services categories to ensure the correct quantities are procured in the appropriate time frames to meet the power system frequency standards.

This paper considers a market-based frequency control solution that dynamically calculates the quantities and timing of FCAS in a manner that is both feasible using current dispatch engines and is also technologically neutral. Market signals should therefore encourage appropriate investment and innovation.

II. FREQUENCY CONTROL

Frequency control is considered a power system security requirement and is a critical part of security constrained dispatch in an electricity market. In a security constrained dispatch optimization, constraints are applied to ensure that the required Frequency Control Ancillary Services (FCAS) requirements are met. Co-optimized dispatch is used to jointly determine both the energy and FCAS dispatch. In the event of any FCAS constraint binding, then the market price for that service is set by the marginal or opportunity cost of providing that FCAS.

This paper will deal mainly with the market provision of FCAS from primary control, which is the most challenging issue for power systems where the inertia has been significantly reduced. The co-optimization presented here includes consideration of sub-networks that may be islanded from the main power system.

III. PRIMARY FREQUENCY CONTROL

Synchronous generators (hydro and thermal) have historically been the main providers of primary control through their governor controls. Governors are typically set to 'standard' droop levels of 4-5% and may have deadbands and limiters applied to modify the response of individual generating units.

Three issues have been observed in contemporary primary control systems:

- The amount of primary control is reducing as more conventional synchronous generators are displaced by VRE generators;

- The amount of primary control response is now more easily controlled with digital governors allowing all parameters (droop, deadbands, limits) to be dynamically adjusted; and
- The inertia of the power system, and in particular some subsystems with high VRE penetration, is reducing. This is increasing the rate of change of frequency and requiring more fast acting primary control to manage power system frequency [2] [1].

Technology is offering solutions through fast acting inverter and storage systems, particularly battery Energy Storage Systems (ESS), that can respond to a frequency change within tens of milliseconds. Further, some of these systems have short-term overload capabilities of around 10 seconds, which is valuable in reducing the magnitude of frequency excursions.

There is an emerging need to establish just how much primary control is required to meet the frequency standard and in what timeframe the service must be provided. If co-optimized energy and FCAS dispatch is done in a principled, technology neutral manner, the need for ad hoc constraints and empirical restrictions on the levels of VRE penetration will be reduced or removed. Adopting a market solution should encourage innovation and signal investment.

IV. Principles of Primary Frequency Control

The swing equation (1), determines the frequency dynamics of the power system [1].

$$2H\frac{d^2\delta}{dt^2} = P_{mech} - P_{elec} \qquad (1)$$

While the supply (P_{mech}) matches exactly the demand (P_{elec}), the power system acceleration is zero and the frequency is unchanging. A disturbance that produces an imbalance on the right hand side of the equation, results in acceleration, with the dynamics being defined by the power system inertia, H.

Typically, a frequency standard will specify the maximum permissible frequency excursion for a credible contingency as well as a time within which the frequency must be restored to the continuous operating band tolerance. An example of a frequency standard is given in Table 1

Table 1 Frequency standard for Australia's National Electricity Market [3]

Condition	Containment (Hz)	Stabilisation	Recovery
accumulated error	5 seconds		
no contingency or load event	49.85 to 50.15 Hz – 99% time		
	49.75 to 50.25 Hz	49.85 to 50.15 Hz within 5 minutes	
generation or load event	49.5 to 50.5 Hz	49.85 to 50.15 Hz within 5 minutes	
network event	49.0 to 51.0 Hz	49.5 to 50.5 Hz within 1 minute	49.85 to 50.15 Hz within 10 minutes
separation event	49.0 to 51.0 Hz	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes
multiple contingency event	47.0 to 52.0 Hz	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes

V. Market Framework for increased VRE Generation

Although this paper is primarily focused on spot market arrangements for FCAS we think that there is a mutually consistent package of market arrangements that can contribute to support higher levels of VRE generation. These arrangements are: short dispatch intervals of the order of five minutes or less; locational marginal pricing; the use of EMS to estimate in real time the system inertia and the inertia any potential islands post credible contingency events; the use of system state estimation to improve the estimates of any system inputs used in the dispatch process; a security constrained real time dispatch optimization which co-optimizes the dispatch of energy, FCAS (including FCAS requirements) and network control ancillary services; market based clearing prices for FCAS; economic incentives to encourage generators to set their electronic governors or equivalent control systems to provide primary frequency response to small deviations; and economic allocation of FCAS costs to encourage efficient investment and operation and improved system security.

VI. Co-optimization approach

Our approach to co-optimizing energy and contingency FCAS is slightly different to the usual approaches to co-optimization.

The normal approach is to categorize the contingency FCAS into categories of fast, slow and delayed contingency services. For each category, the dispatch process determines the requirements directly as an input or indirectly via the co-optimization of requirements. Both of these approaches would take into account any load relief or frequency responsive generation for frequency changes within the frequency standards for the system. The co-optimization of requirements is the more efficient approach as it can tradeoff the size of contingencies with the costs of FCAS.

The other part of the co-optimization is to determine the least cost way of simultaneously meeting the requirements for each contingency service, the regulation services and energy taking into account each generating unit’s capabilities to provide FCAS and energy and the offered prices for these services.

The co-optimization of requirements and the co-optimization of the provision of the services (enabling of the services – reserving the capability) and energy are normally done as a single optimization.

The problem with this approach is that with the introduction VRE technologies and batteries and a corresponding drop in system inertia, the simple categories of contingency FCAS and the assumption that all service providers within a category are providing an equivalent service are no longer fit for purpose.

Our proposed approach to co-optimizing energy and FCAS is to directly model system and island frequency following the most severe credible contingency in the co-optimization. This can be done by:

1) Determining what are the credible contingencies that could affect frequency and/or islanding and their location;

2) Determining potential islands in near real time based on the credible contingencies;

3) Determining inertia for the whole system and any potential islands in near real time by using the EMS system to determine what units and loads with significant inertia are online and then calculating system and potential island inertias;

4) Using measured performance profiles for a benchmark change in frequency over a time period from 0s to, say, 300s for each generator, load or other facility that is in the market to provide contingency FCAS (the measured profiles should be sampled at a small time interval, say, 0.05s for the first 2-4s and then 0.1s for the following 20s);

5) Specifying defined frequency levels in the frequency standards for system and island frequencies post contingency, including permissible times at these frequencies before being restored to nominal (as per *Table 1*);

6) Formulating the co-optimization such that it

a) Directly models system and island frequencies via the swing equation at many discrete times post contingency (this is done via as a set of difference equations that relate the changes in frequency at time t to the power loss at time t considering load relief and FCAS responses);

b) selects the contingency services based on measured performance profiles and their governor responses (the expected FCAS response is determined by the amount enabled x profile x constant x [nominal frequency – frequency]);

c) has constraints to ensure that system and island frequencies are within the frequency standard for each time point and frequency returns to the rated frequency within the required period;

d) co-optimizes the provision of energy and FCAS;

e) co-optimizes the FCAS requirements in near real time by location, based on credible contingencies, inertia and the potential for islanding (in low inertia situations it may be better to reduce the output of a larger generating unit or reduce imports and correspondingly reduce the need for very fast response FCAS capability); and

f) produces shadow prices from constraints associated with the swing equation, such as the power loss equations, that can be used to determine spot prices and the value of FCAS at different times.

The co-optimization is a non-linear programming optimization because it incorporates a simple model of governor response which then involves the product of two decision variables, the frequency at time t and the amount of contingency FCAS enabled for a generator.

The demonstration prototype system used the model building language AMPL and the non-linear optimization solver Knitro.

The modelling of system frequency within the co-optimization does not have to be a very accurate model of frequency post contingency. It just has to be good enough to ensure that enough FCAS capability is enabled to ensure the frequency post contingency stays within the standards but not too much.

Benefits of the co-optimization approach are that it:

- Appropriately rewards service providers based on their response and inertia; and
- prices contingency FCAS on a continuum of time scales, signaling the market values of different response capabilities.

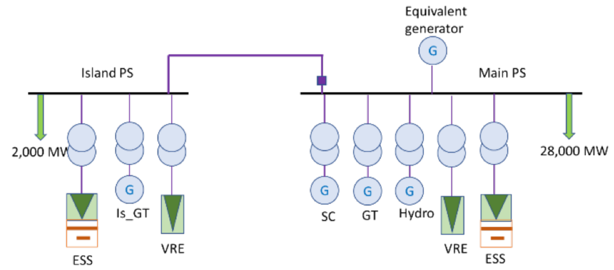

Figure 1: 30 GW power system model used to illustrate primary frequency control co-optimization.

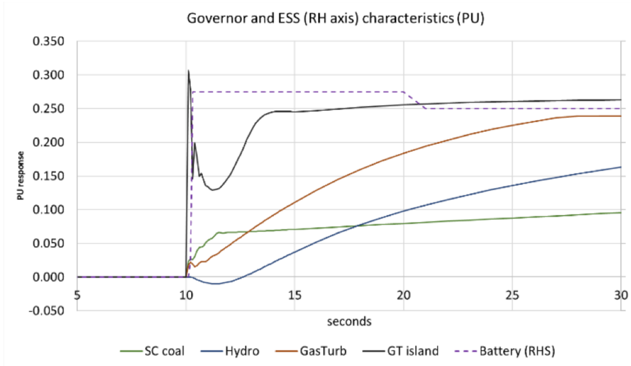

Figure 2: Assumed FCAS response for conventional generators

VII. DEMONSTRATION SYSTEM

A simple 30 GW system, shown in Fig 1. was developed in DIgSILENT PowerFactory to test the proposed FCAS co-optimization approach. The system includes a potential island of 2000 MW with an interconnection rated to 250 MW. Super critical coal (SC), gas turbines (GT), and Hydro generators as well as ESS units can be connected to provide FCAS. All other generation is incorporated in an equivalent generator, with an aggregated inertia. Standard (IEEE) governor models were used to represent primary control responses. The load in the demonstration system is assumed to change by 1.2% per 1.0% change in frequency.

The FCAS providers are assumed to provide FCAS with PU responses shown in Fig. 2. The responses are based on the simulated frequency change for the largest contingency within the main or islanded power system. The latter has very low inertia, hence the difference in the GT and GT Island responses.

VIII. CALCULATING FCAS REQUIREMENTS

It is relatively straight forward to calculate the required primary FCAS to meet the frequency standard. What is less straightforward is to determine when this FCAS must be provided and, for a market, which service providers should be dispatched.

In essence, there is a maximum permissible frequency deviation for a contingency. The amount of FCAS required to ensure this deviation is not exceeded can be calculated based on the largest credible contingency for both the supply side and the demand side (frequency fall and rise, respectively). The supply side contingency will be discussed in this paper but similar concepts apply to demand side contingencies.

Since the demand is frequency sensitive and even some generation may be frequency sensitive, allowance must be made for these and any similar effects in equation (1). The load frequency dependency (LD) and the generator frequency dependency (GD) are used to adjust the demand, L, and any frequency sensitive generation, G. For this paper, it is assumed GD is zero for all G.

In Table 1, the largest frequency deviation for a supply-side contingency is 0.5 Hz. In practice, allowance is made for the starting frequency to be at the lower end of the normal frequency operating band. However, in this paper a permissible frequency deviation, Δ_f, is assumed to be 0.5Hz.

The decline in frequency for the largest credible contingency reaches its nadir when the acceleration in the swing equation is zero. At this time, the supply is equal to the demand. The conditions for this to occur are as follows:

$$P_{mech} + FCAS = L * (1 - LD * \Delta_f) - G * (1 - GD * \Delta_f) \quad (2)$$

Since the RHS is defined by the standard, and P_{mech} is assumed fixed, the primary FCAS response can be calculated.

IX. CASE 1: TESTING THE CO-OPTIMIZATION APPROACH

The FCAS co-optimization using the power system in Fig. 1 was simulated to confirm compliance with the Standard. The focus was on the first 30s after the contingency event even though the co-optimization enabled a suite of FCAS providers to meet the Standard to 600s.

In the test, a 600 MW contingency was applied to the Main system (region 1) but separation of the Island system (region 2) was not considered a credible contingency.

The configuration of generation in the power system model is in Table 2, the offers for energy in Table 3 and the offers for FCAS in Table 4.

TABLE 2: POWER SYSTEM PARAMETERS

Generator type	region	unit size (MW)	online (MW)	H[1] (s)	inertia (MWs)	FCAS max (MW)
Equivalent generator	1	23,050	23,050	2.5	69,150	0
SC_Coal	1	500	3,000	2.5	9,000	600
Hydro	1	250	4,500	5.0	27,000	900
GT - Main	1	250	3,000	2.5	9,000	600
ESS - Main	1	100	200	0.0	0	200
GT - Island	2	250	1,000	2.5	3,000	200
Variable_RE	2	2	3,600	0.0	0	0
ESS - Island	2	100	200	0.0	0	200
Total		24,502	38,550		117,150	2,700

TABLE 3: ENERGY OFFERS

Generator type	price 1 ($/MWh)	price 2 ($/MWh)	quantity 1 (MW)	quantity 2 (MW)
Equivalent generator	0	0	20,000	3,050
SC_Coal	50	70	2,000	1,000
Hydro	60	80	2,600	1,900
GT - Main	100	130	2,000	1,000
ESS - Main	1,000	1,200	70	130
GT - Island	90	95	400	600
Variable_RE	0	0	1,200	0
ESS - Island	1,100	1,300	100	100
Total			20,000	3,050

[1] Note the values for H (inertia) are in s and per MVA and we have assumed MW ratings were 5/6 of the MVA ratings

TABLE 4: FCAS OFFERS

Generator type	price 1 ($/MWh)	price 2 ($/MWh)	quantity 1 (MW)	quantity 2 (MW)
Equivalent generator	1,000	1,000	0	0
SC_Coal	3	4	400	200
Hydro	6	13	150	750
GT - Main	20	30	200	400
ESS - Main	31	41	100	100
GT - Island	20	25	100	100
Variable_RE	NA	NA	0	0
ESS - Island	15	22	100	100
Total			1,050	1,650

The FCAS services selected in the optimization are shown in Table 5. The SC_Coal and Hydro represent the lowest cost and had complementary profiles.

TABLE 5: CASE 1 FCAS DISPATCH FOR INITIAL RESPONSE

Generator type	Energy dispatch (MW)	FCAS enabled (MW)
Equivalent generator	23,050	0
SC_Coal	2,600	110
Hydro	2,600	397
GT - Main	0	0
ESS - Main	0	0
GT - Island	550	0
Variable_RE	1,200	0
ESS - Island	0	0
Total	30,000	507

The simulation of a 600 MW unit resulted in a frequency nadir of 49.49 Hz, just under the target of 49.5 Hz. The co-optimization appeared to be selecting about the correct amount of FCAS. The shape of the responses of the coal and hydro generation were similar to Fig. 4 and the frequency profile was very similar to that in Fig. 3.

X. CASE 2: TESTING THE CO-OPTIMIZATION APPROACH

Case 2 was an extension of Case 1 but the loss of the interconnection was now made a credible contingency. Here, the FCAS selection was co-optimized across both the main and island systems, with the objective being that credible disturbances on either system will meet the Standard requirement of not falling below 49.5 Hz.

The results of the co-optimized dispatch were nodal prices of $70/MWh for the main system and $95/MWh for the potentially islanded system and a combined cost of energy and FCAS of $357,085/h with the following dispatch targets.

TABLE 6: CASE 2 CO-OPTIMISED MAIN AND ISLAND ENERGY AND FCAS

Generator type	Energy dispatch (MW)	FCAS enabled (MW)
Equivalent generator	23,050	0
SC_Coal	2,505	163
Hydro	2,600	264
GT - Main	0	0
ESS - Main	0	0
GT-Island	645	100

Variable_RE	1,200	0
ESS - Island	0	105
Total	30,000	631

The energy-FCAS co-optimization limited the inter-connector flow to 155 MW (of a potential 250 MW) as this minimized the cost of both energy and FCAS for the whole system. Flow was reduced to lower the contingency size and more expensive Island generation used ahead of imports.

For this scenario two disturbances were examined:

- A 600 MW generation trip on the main system
- Loss of the interconnector, representing a disturbance of 150 MW

The FCAS dispatch for the 600 MW disturbance is higher than Case 1 and includes FCAS enabled in the Island system to control frequency if the interconnector is opened.

Loss of the interconnector presents the Island system with a 150 MW shortfall and the main system with a 150 MW surplus. For the low inertia island power system, islanding with the loss of 150 MW of import is a severe contingency.

The FCAS dispatch included, for the Main system, two 500 MW SC_Coal units, each backed off to 400 MW, to provide 160 MW of FCAS and five 250 MW hydro units, each backed off to 100 MW, providing a further 250 MW of FCAS. For the island System, two GTs provided the 100 MW of FCAS with the remaining 100 MW from an ESS.

The results for a 600 MW contingency in the main system are presented in Figs. 3, 4 and 5. This confirms the main system meets the Standard.

The results for the island system for the loss of 150 MW interconnection are presented in Fig. 6 and Fig 7. The simulated frequency at the nadir is 49.6 Hz which is slightly higher than required.

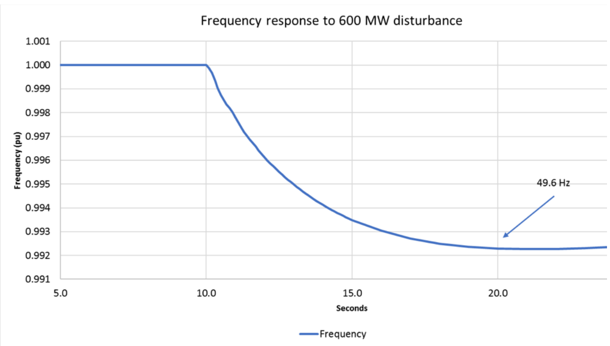

Figure 3: Case 2: Frequency for 600 MW contingency

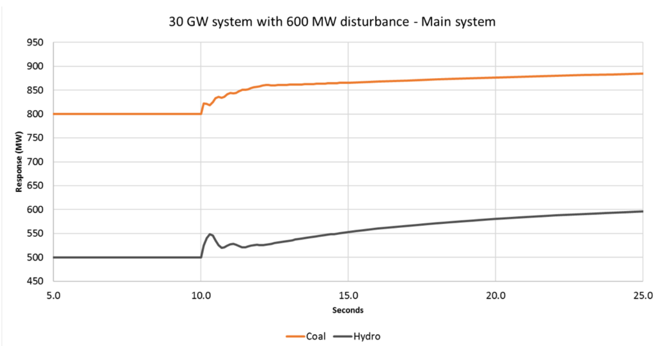

Figure 4: Case 2 Main system response to 600 MW Contingency

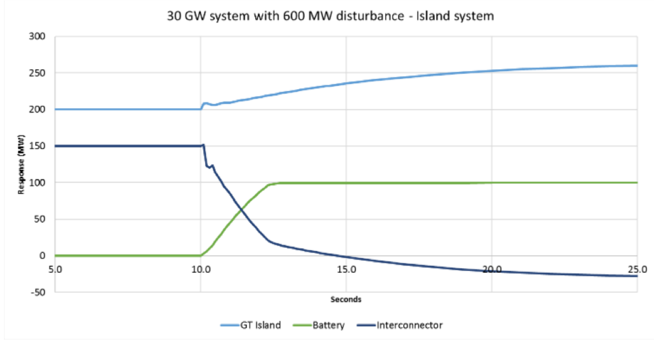

Figure 5: Case 2 Island system response to 600 MW Contingency – Interconnection, Gas and ESS

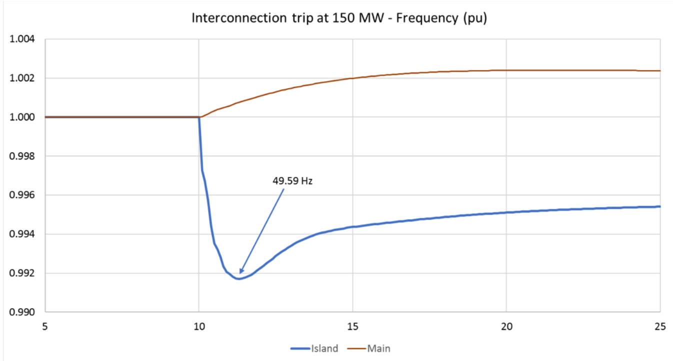

Figure 6: Case 2: Island frequency for 150 MW contingency

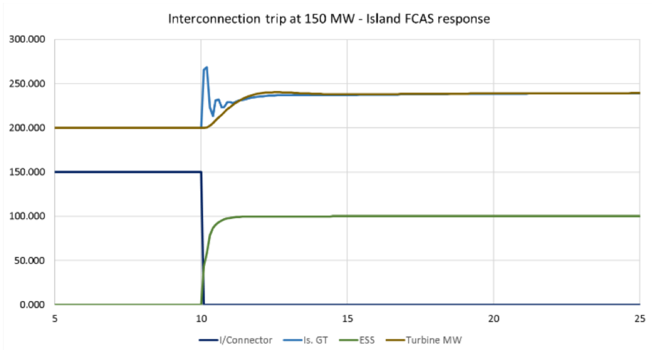

Figure 7: Case 2: Island system response to 150 MW Contingency – Gas and ESS

n item of interest in Fig. 7 is the GT's significant inertial response and the slower turbine response. The 'Is. GT' curve is the combined inertial and turbine response. The turbine output is shown as 'Turbine MW'. The inertial response is significant and in its absence, more (expensive) ESS response would be required.

For this very low inertia situation the co-optimization overestimated how much FCAS was required and is probably due to the use of the simple difference equations in the co-optimization that did not fully account for the inertial response of units to the rapid change in frequency. Possible improvements in future models would be finer sampling of the first 0.0s to 0.5s and explicit incorporation of the rate of change of frequency into the model.

XI. Pricing FCAS Using Co-optimization Approach

The nodal energy prices of $70/MWh for the main system and $95/MWh for the island system can be determined from the shadow prices of the nodal energy balance constraints. Finding a way to price the FCAS is not so straight forward.

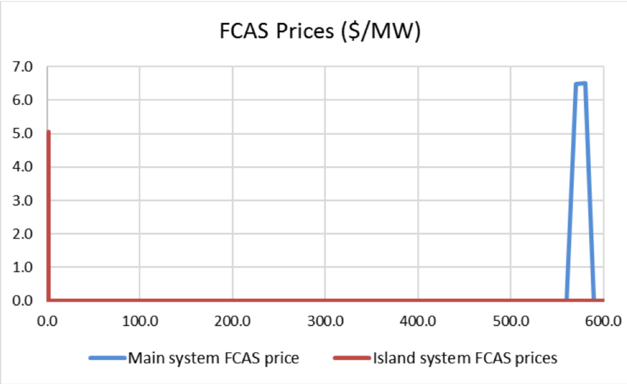

Figure 8: FCAS Prices for Main System

The shadow prices for the main system and island system frequency constraints for the 600 MW and 150 MW contingencies respectively were non-zero at 1.8 s for the island system and at 580 s for the main system (not shown in this paper). These shadow prices reflect the value of energy provided via FCAS prior to these times but are not easy to use to determine payments to the FCAS providers.

However, the shadow prices for the power loss constraints can be used to determine FCAS payments. These shadow prices for the main system and the island system are presented in. These prices, when multiplied by the expected supply of FCAS delivered by each provider at each time interval following a contingency, are the revenues the FCAS providers would be paid under spot market arrangements. If these prices are used, every provider will always be guaranteed to earn at least their offered prices.

The FCAS providers in the island system can earn revenue from providing the local FCAS for the islanding scenario as well as providing FCAS for the overall system. The profile of these prices, shown in Fig. 8, may be somewhat arbitrary given the large number of constraint shadow prices compared to the number of FCAS provider profiles.

For the main system, the non-zero FCAS prices occur at about 580s. This is when the constraint to return the system to nominal frequency binds. The prices in the early time periods are zero because the Main system has a reasonably high inertia and the local FCAS requirement for the Island system has required fast response FCAS, which is also considered for the main system. The FCAS prices for the Island system are high for FCAS delivered in the first 1.8s. This example illustrates how the co-optimization with its explicit modelling of frequency can automatically determine whether the market needs very fast acting FCAS, as was the case for the island system, or only needs slower acting FCAS as was the case for the Main system. Within this co-optimization framework the value of inertia and the benefits of dispatching a new inertia-unit, can be assessed either by changing the inputs to the optimization (i.e. adding an extra unit) or by trying to incorporate this option directly into the optimization via binary or integer variables.

XII. DISCUSSION AND CONCLUSIONS

A market-based approach to frequency control in power systems with high levels of VRE is presented in this paper. The approach is amenable to frequency over a period of several hundred seconds, though the focus in this paper has been on the initial 20-30s of primary control.

A market-based approach for frequency control has the following benefits:

- Technology neutral, which will encourage innovation outside of traditional FCAS providers;
- provides price signaling that values not only the quantity of service provided but also the timing of the response;
- able to value inertia and avoid the need for ad hoc ‘standards’ forcing non-market provision of FCAS;
- able to simultaneously optimize FCAS dispatch over one or more potential islands and the rest of the power system; and
- able to preserve security by transparently constraining resources required to meet the frequency standard rather than relying on ad hoc and arbitrary limitations on VRE output.

XIII. FUTURE WORK

The concept proposed in this paper is by no means perfect but is intended to demonstrate that market-based approaches can co-optimize FCAS to comply with a nominated standard.

Specific improvements to overcome short-comings identified in the approach outlined in this paper include:

- A better way to characterize the FCAS responses. It may be better to define a ‘standard’ frequency characteristic test for a normal and a low inertia system that will give (slightly) conservative results.
- Improved price signaling to include a shadow prices for inertia and inclusion in spot market arrangements;
- Incorporating the method in pre-dispatch calculations to signal the value of FCAS and potential constraints;
- Reformulating the model as a linear programming approximation or a more efficient non-linear program to meet operational performance standards;
- Improved control system for the ESS to provide differential action to increase the initial response (and FCAS value) for high df/dt conditions.

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