Emerging Rate-of-Change-of-Frequency Problem in the NEM: Best-practice Regulatory Analysis of Options

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1 Executive Summary

1. An electrical power system is designed to run at a nominal frequency, typically 50 or 60 Hz. Power system security cannot be maintained, and the system may collapse, if an event such as a sudden generator outage occurs and the rate of the subsequent frequency change is not managed. Historically in the National Electricity Market in Australia[1] (the "NEM"), this Rate of Change of Frequency (RoCoF) has been managed by the resistance to frequency change given by the plentiful system inertia, a byproduct of energy production by thermal and hydro generators. However, increasing penetration of renewable generation, which does not provide system inertia, raises questions about whether this previously free system inertia has an emerging value and how to best manage RoCoF in future.

2. The changing generation mix also affects other aspects of power system security. These include frequency regulation, availability of reserves, fault level and transient stability[2]. This report specifically investigates RoCoF management following contingency (unexpected) events, but notes that this may interact with these other issues or have related costs and benefits.

3. This report primarily considers the question of how decisions about investment and operation of technical RoCoF management solutions should best be made in the context of the NEM. It considers whether and how these decisions should be made by regulatory bodies, system operators, or markets, and develops a framework based on the National Electricity Objective and principles of best practice regulation to define what is meant by the "best" option for RoCoF management policy. It does not analyse the system integration implications of the potential technical solutions.

4. The analysis draws on international experience, noting that this experience is in its early stages, and that the options proposed internationally are yet to be fully implemented.

[1] The NEM interconnects the regional market jurisdictions of Queensland, New South Wales, Victoria, South Australia and Tasmania.
[2] These are discussed in detail in [5]

5. Figure 1 illustrates a simplified graphical view of what is the "best" option. In this report, a series of options are evaluated in an indicative analysis, with the parameters of need for confidence in deliverability, which is most dependent on the urgency of the problem, and materiality of the RoCoF management problem found to be most significant in determining which option best addresses the objective.

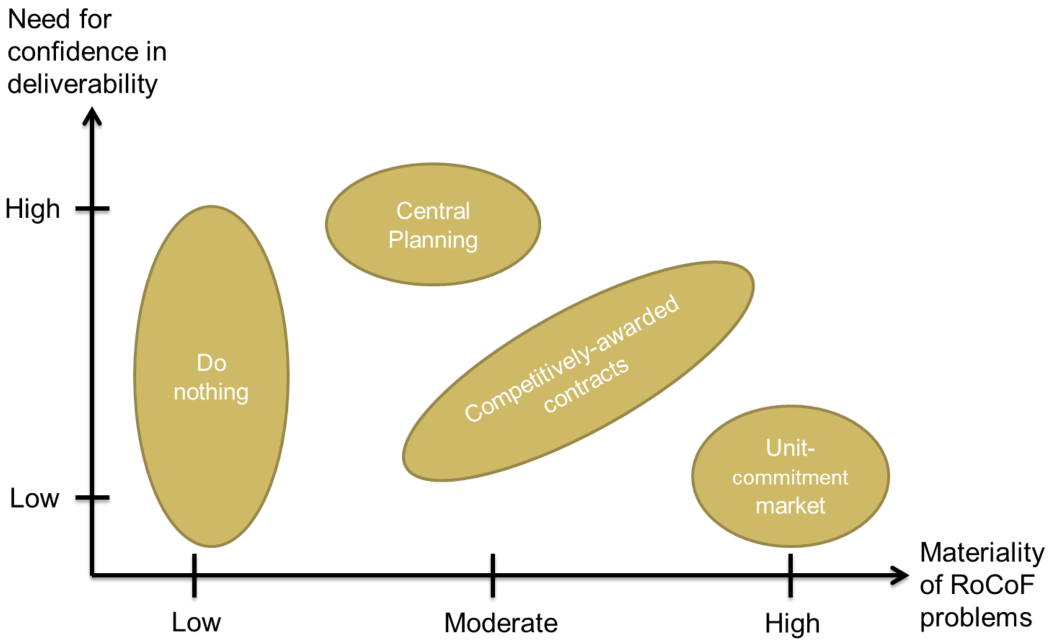


Figure 1 - Best Options for Different Situations

6. For the NEM, the analysis suggests that, in the near-term, a centrally-awarded contract approach is worth consideration. In the long term, given that the RoCoF management challenge is likely to increase as renewable penetration continues to increase, the analysis suggests a unit-commitment market may be the optimal approach, with R&D recommended on such a unit-commitment market in the near-term. Significant uncertainty accompanies these recommendations given the range of RoCoF management options and the pace of change in energy market conditions and in technological development. Action by the COAG Energy Council to commission a review on a policy trajectory is recommended.

7. The analysis identifies areas for significant further work that would inform quality policy making on the RoCoF management problem. These include the development of frameworks for quantification of the problem, the development of practical market designs, detailed preparatory work on central planning options and regulatory work on the participation of network service providers in RoCoF management.

2 Context

8. Frequency management is essential for the secure operation of a synchronous power system. Historically, the RoCoF component of frequency management has been ignored due to plentiful and free power system inertia from conventional synchronous generators, a situation which is being challenged in the NEM and internationally by the increasing entry of non-synchronous renewable generation. The scarcity of RoCoF management services varies temporally with system conditions, particularly evident overnight when it is windy. Short-term and long-term economic costs arise if RoCoF management services are not managed efficiently.

2.1 Historical Situation

9. Historically, system inertia has been plentiful and free in large interconnections with predominantly synchronous generation, such as the NEM. This is common with the power systems of developed economies which run on fossil fuel, hydro and nuclear energy. This plentiful system inertia, shared across a synchronous network for RoCoF purposes, keeps the RoCoF at an easily-handled level.

10. Fossil fuel, hydro and nuclear plants typically have large turbines, synchronous to the power system, which provide system inertia for free whenever operating. Many of these plants prefer to stay on for long periods of time. In a competitive real-time economic dispatch[3] market such as the NEM, such slow-ramping plants arrange their energy offers to manage their self-commitment[4] to ensure they are available when the energy price is attractive. This gives a base level of synchronous system inertia.

11. The characteristic inertial response of a plant is explicitly valued at zero in compensation paid in the NEM for responses to contingency frequency events[4]. Inertia is so plentiful in the NEM mainland power system that its level is not considered[5] in power system operation[5]. In 2013, the NEM mainland power system had system inertia estimated at

[3] A real-time economic dispatch process maximises net market benefit in an optimisation process
[4] Commitment describes the process of a plant warming up to be ready to offer energy to the market, in a time period longer (often many hours for coal) than the dispatch interval.
[5] Except when SA is at credible risk of separation

above 90,000 MW.s at all times, where approximately 16,000 MW.s is needed to keep a large contingency event to a manageable RoCoF[6].

2.2 Challenge from Non-Synchronous Renewable Generation

12. Modern wind turbines do not provide conventional system inertia as their rotating mass is electrically decoupled from, and therefore not synchronised to, the power system. Solar PV systems do not have a rotating mass so cannot provide conventional system inertia.

13. Non-synchronous renewable generation is increasing in capacity in the NEM and worldwide. This is expected to continue in response to falling costs and clean-energy incentives.

2.3 What are the Economic Issues?

14. An immediate issue for wind farm investors and operators is that their output may be curtailed at times of low system inertia so that more synchronous (thermal or hydro) plant can run to ensure sufficient system inertia for power system security. This has the economic cost to the system for that trading interval of dispatching more costly energy.

15. The longer term issue is how to, with respect to RoCoF issues, maintain a secure power system in an economically efficient manner. With competition from renewables depressing wholesale prices, thermal plant, which currently provide inertia for free, or can be paid to do so for fuel cost at the margins of profitable operating periods, may withdraw from the energy market. Synchronous inertia then becomes scarce at times. To maintain power system security, a means to incentivise provision of RoCoF management services is needed.

16. A further economic issue concerns the ability of the power system to continue to support large contingencies such as large interconnector flows and large generation plant, which drive large RoCoF management requirements. Large interconnector flows allow a more efficient dispatch for the whole system, and large generation plant is more efficient at its designed capacity.

[6] Based on figures 3-5 and 3-7 in [5], for a contingency size of 650 MW with RoCoF of 1 Hz/s

2.4 Temporal and Locational Scarcity of Conventional System Inertia

17. Conventional system inertia is low when few thermal and hydro plants are operating. Non-synchronous renewables such as wind and solar PV are near zero marginal cost, so will displace some conventional generation in an economically efficient dispatch. At low load and high renewable potential, the renewables are able to displace a large proportion of the conventional generation, leaving few plants operating. Overnight with high wind is the time where low conventional system inertia is most likely to occur[5].

18. Power system inertia for RoCoF management purposes is summed across a synchronous interconnected system[5] so does not vary locationally. However, interconnectors complicate this. Tasmania is not synchronously connected to the mainland NEM as the interconnector is HVDC. South Australia is intermittently at credible risk of the loss of its synchronous interconnector, at which times its local system inertia is relevant.

2.5 How Big is the Problem in the NEM?

19. Tasmania is connected to the mainland NEM by a HVDC link so is effectively a power system island where inertia is concerned. The small system size (around 3 GW of mostly hydro generation[10]) and relatively large in-feed from BassLink (500 MW[15]) make inertia an ongoing problem[31]. There is 373 MW of wind capacity installed as at May 2014, with a further 1,400 MW of wind capacity publically announced[10].

20. South Australia is connected weakly to the NEM, and at times is at risk of separation, which could result in low system inertia[5]. Instantaneous wind penetration (that is, the proportion of energy in a dispatch interval supplied by wind) peaked at 88% of SA demand in 2012-2013[6].

21. AEMO's Wind Integration Studies in 2013[5] conducted market modelling that examined how often a low inertia situation would arise up to 2020. The key assumption was that total installed wind generation in the NEM would be 11.5 GW, up by 8.9 GW from 2012. This modelling found that with economic dispatch that ignored system inertia level, system inertia would be below acceptable levels for 30-40% of the time in Tasmania, and 30% of the time in South Australia[7]. Victoria was shown to have times of

[7] This considered a 250 MW contingency when at credible risk of separation, and 650 MW non-credible loss of Heywood interconnector. The situation in SA is complicated by uncertainty, discussed in Section 7.2.3 of [5], about when RoCoF would need to be managed, given that SA is occasionally at credible risk of separation.

low inertia, but can rely on inertia from other NEM regions due to its strong interconnections. Modelling in NSW and QLD found that wind generation did not displace sufficient synchronous generation to significantly depress system inertia.

22. It is beyond the scope of this report to estimate values for the economic impacts. It would be useful further work to establish a framework for quantifying these impacts.

2.6 What is Happening Internationally?

Box 2.1 – Background on International Renewables and RoCoF Management Experience

Ireland and Northern Ireland – the Single Electricity Market ("SEM")

In the SEM, wind penetration by capacity is predicted to rise to 42% by 2020[26]. Currently, non-synchronous generation is limited to 50% of instantaneous system load to address contingency RoCoF and other related issues[26]. Reviews over 5 years have culminated in the definition of a new set of system ancillary services in the "DS3" project, which in July 2014 released its plan for a centrally-auctioned contract-based market for system services[45]. Along with its statutory objective to promote competition, the SEM must address Ireland's 40% renewable electrical energy by 2020 target[20] and the EU's mandate on minimising curtailment of renewables[45].

Texas – ERCOT

ERCOT had 11 GW of wind in 2013, out of a seasonally-varying load of between 22 and 70 GW, with record instantaneous wind penetration of 35%[29]. ERCOT concluded a review[29] in 2014 of its ancillary services as previous ancillary services, designed for steam-generation dominance, were not longer optimal. A synchronous inertia reserve and a fast-frequency reserve service are proposed for RoCoF management.

Quebec – Hydro Quebec

Hydro Quebec in Canada is adding wind energy to its predominantly hydropower system, forecasting 25% penetration by capacity in summer (low load) by 2015[14], and is requiring wind farms to provide an emulated inertial response [18]. It has worked with wind-farm manufacturers since 2009 to define specific parameters that suit the power system requirements. Studies of system integration are ongoing[14].

23. A small number of large interconnections internationally, recognising the challenge from increasing renewables penetration, have developed plans for RoCoF management[18, 29, 45]. Box 2.1 gives background information on renewables and RoCoF management in these places. The plans are recent and yet to be fully implemented. The SEM in Ireland

and Northern Ireland and ERCOT in Texas operate with competitive-market aims similar to those of the NEM, so their work on RoCoF management is informative for the development of RoCoF management service markets in the NEM, while the work by Hydro-Quebec on synthetic wind inertia integration is informative for central planning approaches. Detailed insights are referenced in the relevant sections of this document.

3 Technical Background

24. Power system security is fundamental to the operation of a power system. It is the maintenance of the power system in a state where it can tolerate a disturbance (a "credible contingency event") while remaining in a satisfactory state, and to return to a secure state within 30 minutes[8]. The Rate of Change of Frequency (RoCoF) after a contingency (unexpected) event must be managed to meet standards for system frequency and to prevent system collapse. The realised RoCoF depends on the contingency event size and the amount of inertia in the power system, both of which may be operationally managed.

3.1 Power System Security and Frequency Operating Standards

25. Section 4.2 of the National Electricity Rules[2] covers power system security. In addition to tolerating credible contingencies, the power system must also have sufficient emergency measures to protect itself against collapse in the event of less likely multiple disturbances.

26. The NEM is a synchronous power system, where all synchronous machines (generators and motors) on the network run at the same AC (alternating-current) frequency. This is 60 Hz in North America and 50 Hz in Australia and most of the rest of the world. To keep this constant, demand and supply must be instantaneously matched. A contingency (unexpected) event upsets this balance and causes frequency to decrease if demand exceeds supply (for example due to a generator trip), or increase if supply exceeds demand (for example due to a network failure).

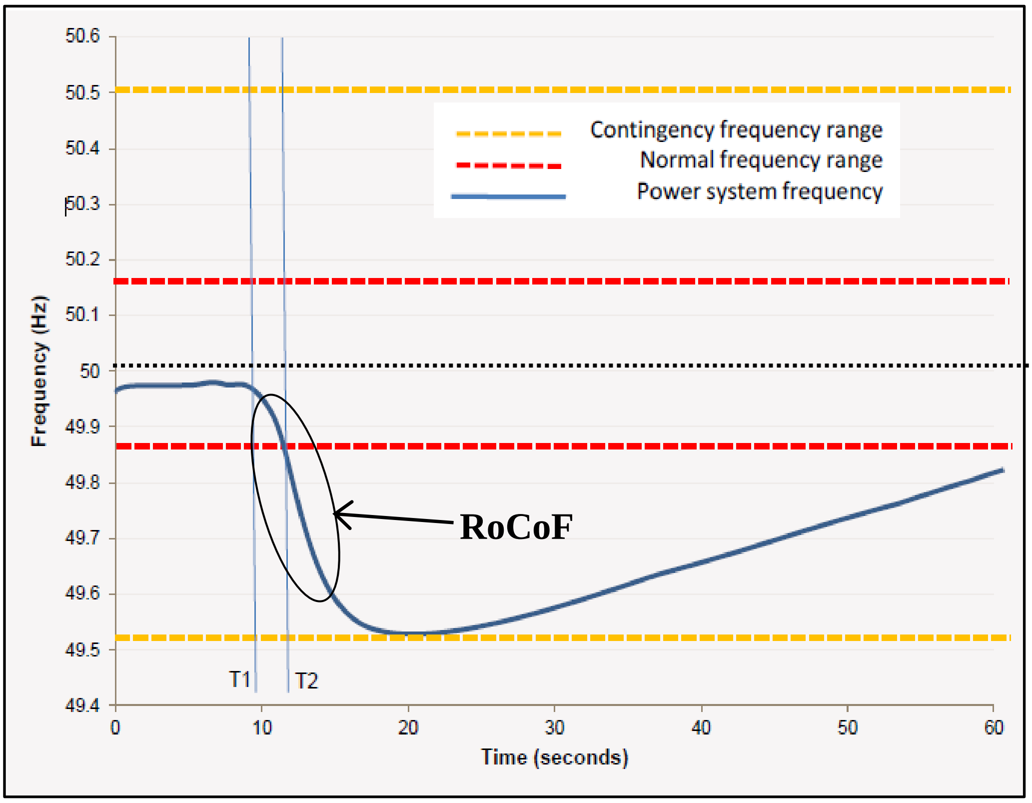
27. The frequency operating standards are set in the NEM by the Reliability Panel. The standards exist as many types of equipment, particularly rotating machinery, rely on a

[8] Such events, of a material size, occur with a frequency of between once a week and once a month in the NEM, according to the Principal Engineer, Systems Capability, AEMO[34]

steady frequency, with minor short-lived fluctuations, for safe, effective and efficient operation[36]. The frequency operating standards require the system operator to maintain the frequency within “normal” bands for normal (no contingency) operation, and within “contingency” bands when a credible contingency event has occurred.

28. If the frequency moves outside the contingency band or the RoCoF becomes too high, emergency protection equipment may disconnect generators and loads, which has an undesirable economic cost for a single credible contingency event. After multiple contingency events, load-shedding (the involuntary disconnection of load) can be used to restore a satisfactory operating state.

29. Figure 2 shows a typical waveform for a frequency excursion following a generator trip. The slope of the frequency as it falls is the RoCoF of interest. Note that it falls sharply until it starts to slow and then turn up as fast contingency reserve services take effect.



Source: AEMO Wind Integration Studies[5], fig 3.1

Figure 2 - Waveform of a Frequency Excursion

30. The fast-raise and fast-lower contingency reserve services provide a response within 6 seconds to a frequency disturbance. This is typically provided by thermal generator

governors that adjust their output in response to a significant frequency deviation. RoCoF management needs to be faster than this to cover the time before this occurs.

3.2 What Defines a Manageable RoCoF?

31. Workable RoCoF limits are indirectly determined in the NEM. The connection standards for new connections[9] specify minimum access (1 Hz/s for 1s) and automatic access (4 Hz/s for 0.25s) standards for RoCoF where the plant must be capable of continuous uninterrupted operation. Existing generation has some known RoCoF tolerance and there are under-frequency protection relays with RoCoF trip points. The correct operation of emergency protection equipment that manages multiple contingency events requires some extreme maximum RoCoF.

32. The maximum manageable RoCoF is limited by the speed, cost and availability of fast-raise and fast-lower reserves. The frequency operating standards require system frequency to stay within specified frequency bands after contingency events and to return to the normal band in a specified time. The realised RoCoF determines how far the frequency will fall or rise before the fast-raise or fast-lower reserves (such as spinning reserve) take effect, affecting the quantity of fast-raise and fast-lower services required to comply with the frequency standards[10].

3.3 Relationship between RoCoF, Power System Inertia and Contingency Size

33. RoCoF after a contingency event depends on the size of the imbalance caused by the event and the inertia of the power system.

34. Typical large contingency events include generator and interconnector trips and other network faults. To manage RoCoF to a desired level after any credible contingency, sufficient system inertia must be available to balance the largest credible contingency on the system, for both under and over frequency events. In this report, credible contingencies only are considered to be of interest to simplify the discussion, but it is noted that the power system operator may[11] select non-credible but significant contingencies such as interconnector failures as the largest contingency for RoCoF management, or take a more complex probabilistic approach.

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[9] S5.2.5.3 of National Electricity Rules[2]
[10] In Tasmania, islanded for RoCoF purposes, fast-raise services are already dispatched based on an estimate of system inertia. The requirements can become infeasibly large if system inertia is low[5].
[11] if allowed by the Rules, a complex regulatory issue which is not examined here. See [11].

35. Power system inertia is summed across the synchronous interconnected system[5], meaning large interconnections will have more, for a similar generation mix. Synchronous generators provide a fixed inertia when they are operating. The effective inertia of a power system can be increased by alternative technologies that inject energy to counter the imbalance.

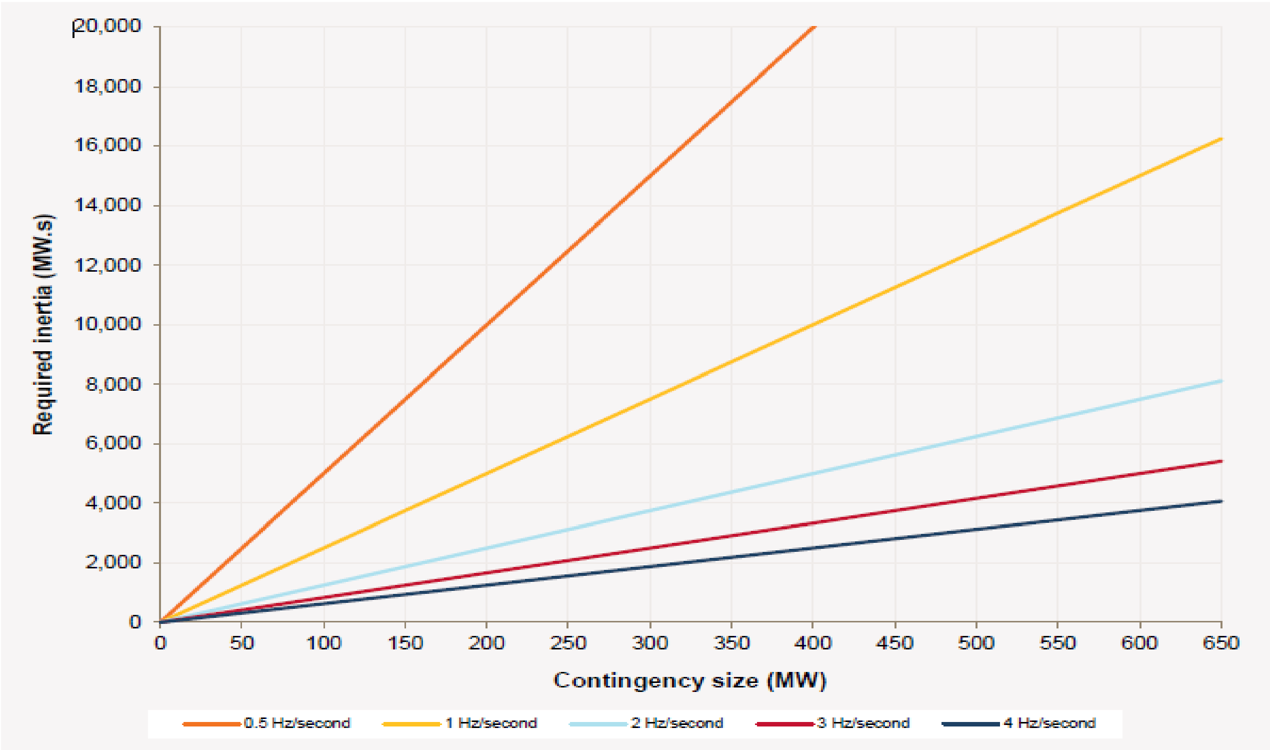
3.3.1 Mathematical Relationship

36. RoCoF is linearly related to the size of the contingency event (the sudden power imbalance in the power system). It is inversely proportional to the quantity of system inertia. Equation (1) describes the relationship[16]. The units are contingency size in MW and system inertia in MW·s, f_0 in Hz, RoCoF in Hz/s.

$$\mathbf{RoCoF} = \frac{\mathbf{df}}{\mathbf{dt}} = \frac{\mathbf{1}}{\mathbf{2}}\,\mathbf{f_0}\,\frac{\textbf{contingency size}}{\textbf{system inertia}} \qquad (1)$$

37. Inertia is the property of a physical body to resist a change in its motion. Here it refers to the ability of the power system to resist a change in frequency when there is a power imbalance. Synchronous generators and loads (that is, those that are spinning synchronised to the power system frequency, or some multiple of it) contain a spinning mass that holds kinetic (or rotational) energy. This energy is available to be released (or more absorbed) to counteract a sudden imbalance due to a contingency event. The more of this energy there is available, the less the change in frequency for a given imbalance.

38. Given a desired maximum RoCoF, the maximum contingency size in the power system defines the system inertia required. Figure 3 shows equation (1) graphically.



Source: AEMO Wind Integration Studies[5], fig 3.7

Figure 3 - Instantaneous RoCoF versus contingency size and power system inertia level

3.3.2 What determines contingency sizes?

39. Large generators can have a capacity of several hundred MW per unit. The contingency size is the output level of the plant, which could be reduced to lower the maximum contingency size, and therefore the system inertia required for the desired RoCoF.

40. Interconnectors can be very large, such as the Heywood Interconnector in the NEM which will increase from 460 MW to 650 MW in 2016[11]. Flows on interconnectors may be reduced at times where they are at risk of failure to reduce the inertia and reserve requirements. Other network contingencies can be significant, especially for a single feeder with a large generator (such as a remote wind farm) or load attached. A network failure can cause an under- or over-frequency event in a region.

41. Sudden disconnection of large loads is an over-frequency issue. Large loads (or infeeds, such as BassLink[12]) may have matching generator trip equipment to effectively reduce the contingency size.

[12] The Frequency Control Special Protection Scheme rapidly disconnects industrial load or generators if BassLink trips[5]

3.3.3 What determines the level of system inertia?

42. For a particular generator (or load), the inertia it provides to the system depends on its physical construction. The inertia constant H is the ratio of the kinetic energy at nominal frequency to the rated power (S_{nom}) of the unit[16]. The inertia is then $H \cdot S_{nom}$, expressed in MW·s. This value, typically in the range 2.5s – 7.5s[16], depends only on whether the machine is operating [5]. Large thermal plants are typically at the higher end.

43. The inertia of the power system is calculated as the sum of the inertia from all of the operating synchronous machines that are synchronously connected[5]. It is not a local issue except where a region is at risk of islanding. The NEM, apart from Tasmania, is a single synchronous network. Tasmania, with its HVDC BassLink, cannot access mainland NEM inertia. This is distinct to other reserve services such as fast-raise which may be provisioned across a HVDC interconnection.

44. A technical detail is that the calculation of system inertia must consider for a generator trip that the available system inertia is reduced by the inertia of that now-disconnected generator. This same situation exists for frequency-control ancillary services where a generator cannot provide reserves against its own failure.

3.3.4 How can effective system inertia be increased?

45. The physical property of a rotating mass releasing energy as it slows down is the conventional understanding of system inertia. A synchronous condenser is a machine that has a synchronised spinning mass but consumes a small amount of power. These are typically used for reactive power management but can also increase the synchronous inertia of a power system.

46. The inertial effect of the synchronous machines can be supplemented by other devices that counteract the sudden power imbalance[22]. Such action would leave less of an imbalance for the synchronous machines to correct, giving a slower frequency change. It is necessary to inject such power quickly to slow down the RoCoF before the frequency level changes too much. A proposal by ERCOT[29] for a fast-frequency response to supplement the synchronous inertia asks for full power in half a second. Candidate technologies include battery systems[22], synthetic inertia equipment on wind farms[13], and very fast-tripping interruptible load.

47. A minimum level of synchronous inertia is likely to be required to manage the truly instantaneous RoCoF after an event and to ensure some extreme maximum RoCoF following multiple contingency events. This report does not attempt to quantify what that level is, but notes that in proposed schemes internationally, a minimum synchronous inertia level is sought in addition to other RoCoF management services[29, 44].

48. The technical detail of the integration into the power system of this alternative RoCoF management is beyond the scope of this report. Section 5.2 examines the technical and economic properties of these technologies.

4 Institutional Arrangements and Accountabilities

49. The NEM is a complex interconnected power system. The National Electricity Law is the overarching instrument and the National Electricity Rules (NER) implement the law. The key players are: COAG Standing Council on Energy and Resources (SCER), Australian Energy Market Operator (AEMO), Australian Energy Regulator (AER), Australian Energy Markets Commission (AEMC), Network Service Providers (NSPs) and Generators. NSPs are economically regulated monopolies.

50. AEMO is responsible for power system security, frequency control, central dispatch and load forecasting. The Reliability Panel determines the guidelines and standards for power system security and system frequency. Generators are required to follow dispatch instructions and to self-commit. The AEMC determines the Rules, while the AER implements, monitors, and enforces compliance with the Rules, and economically regulates the NSPs. The SCER provides policy oversight and co-ordination.

51. Introducing new RoCoF management regulations, markets or network equipment is complex. AEMO is responsible for operationally managing RoCoF problems and determining technical requirements. The Reliability Panel is responsible for updating the frequency control standards to reflect emerging cost/benefit trade-offs around RoCoF management. A rule change is required to implement a market or regulatory solution to RoCoF problems. The AEMC is responsible for making rule changes, at the proposal of interested parties, with technical input from AEMO. NSPs require approval from the AER of prices to enable funding to install new capital equipment such as synchronous

condensers. Both the AEMC and AER must consider the National Electricity Objective in their approval processes.

52. Table 1 references the accountabilities relevant to RoCoF management.

Table 1 – Accountabilities in the NEM

Area	**What is the responsibility?**	**Who is accountable?**	**Reference**[13]
Policy Oversight	To facilitate national oversight and coordination of governance, policy development and program management to address the opportunities and challenges facing Australia's energy and resources sectors into the future.	SCER[14]	[21]
Rules	To develop and maintain the National Electricity Rules, based on proposals for rule changes from interested parties.	AEMC	[1]
	To monitor the compliance of the electricity market with the NER and to economically regulate the NSPs.	AER	[12]
Power System Security	To maintain power system security such that the power system will remain in a satisfactory operating state following a credible contingency.	AEMO	4.3.1(a) 4.2.4
	To determine the power system security and reliability standards, and develop and publish principles and guidelines to determine how AEMO should maintain power system security while taking into account costs and benefits.	Reliability Panel	8.8.1(2)
	To ensure that load-shedding facilities initiated by frequency conditions are available to handle multiple contingency events, up to 60% of load.	AEMO	4.2.6(c), 4.3.1(k)(2), 4.3.2(h)
Frequency Control	To determine the frequency levels for the operation of the power system (the "frequency operating standards").	Reliability Panel	8.8.1(2), Glossary
	To control the power system frequency and ensure the frequency operating standards are achieved.	AEMO	4.4.1
	To ensure within the extreme frequency excursion tolerance limits all of its power system equipment will remain in service.	NSPs	S5.1.3
	To provide uninterrupted operation for specified RoCoF and frequency bands.	New generators	S5.2.5.3
Planning and Forecasting	To prepare the NTNDP (National Transmission Network Development Plan) and publish its inputs including demand forecasts and expected generation costs.	AEMO	5.20
	To prepare an indicative load forecast from 1 day to 24 months ahead.	AEMO	4.9.1

13 Sections and clauses references are to the National Electricity Rules[2]
14 The Council of Australian Governments Standing Council on Energy and Resources

Area	What is the responsibility?	Who is accountable?	Reference[13]
Dispatch	To operate the central dispatch process to maximise the value of spot market trading, subject to constraints, and to prepare a pre-dispatch schedule.	AEMO	3.8.1(a) 3.8.20
	To notify AEMO of their intended commitment/decommitment times, and for slow-starting units to self-commit to be eligible for dispatch.	Scheduled Generators	3.8.4 3.8.17
	To follow the dispatch instructions.	Generators	3.8.23
Load-Shedding	To ensure that load-shedding facilities initiated by frequency conditions are available to handle multiple contingency events, up to 60% of load.	AEMO	4.2.6(c), 4.3.1(k)(2), 4.3.2(h)

5 Economic Nature of the Service and Candidate Technical Suppliers

53. The economic properties of the "RoCoF management service" are examined in this section to understand how such a service may be provisioned. Technical solutions that are candidates for supplying this service are examined to understand how they fit economically into a market or regulatory design. An indicative examination of the costs of these technologies does not eliminate any from consideration.

5.1 Nature of the RoCoF Management Service

54. A RoCoF management service is defined here as any service that meets the power system's technical requirements of providing a response that assists in slowing the fall or rise in system frequency due to a contingency event. The definition of the precise technical requirements for such a service or combination of services is a complex technical task. It is beyond the scope of this report to make this definition, but it is noted that some base level of synchronous inertia service is necessary.

55. Effective RoCoF management is a public good[15]. The system frequency is common across the network[16], and RoCoF management services are summed across an AC interconnected system[17]. A failure in security of supply due to insufficient RoCoF

[15] Economists define a "public good" as a good where individuals cannot be excluded from its use, and where use by one individual does not reduce availability to others. The associated "free rider" problem occurs when collectively the participants would benefit from an increased supply of the good, but an individual does not have sufficient private incentive to pay to increase the supply, so participants choose to "free-ride" on others, meaning the good is typically under-supplied.

[16] "In an interconnected alternating current power system, system frequency is essentially the same at every location." p5 of [36]

[17] See Section 3.3.3

management could mean load-shedding and blackouts affecting much or all of the power system. Being a public good means that participants are not inherently incentivised to provision the efficient level of RoCoF management.

56. Contingency events are infrequent and the ability to respond to such events is the service of value, so providers of RoCoF management services are best incentivised by payments related to service availability rather than on response to actual events.

57. Section 2.4 explained that the scarcity of RoCoF management services varies temporally, as provision by synchronous generators is incentivised by energy markets.

5.2 Economic and Technical Characteristics of Technical RoCoF Management Solutions

58. Many technical solutions exist that provide RoCoF management services. Table 2 summarises the key economic features against the list below, while the text following provides a detailed explanation. These parameters inform the later analysis.

- A base level of **synchronous inertia** may be required, and is interchangeable with **non-synchronous RoCoF management** above that level.
- The **characteristics of service quantity** is important to understand how the technical solution could fit into different market designs.
- If a technical solution is **capital intensive**, it requires the ability to recover sunk costs, such as through infra-marginal rents in a marginal-price market.
- The **cost to supply RoCoF management service** indicates the variable cost to supply the service, given existing capital equipment.
- The **ramp time of RoCoF management service** is relevant to how such a service could respond to a temporally-varying scarcity in RoCoF management.

59. Points of particular relevance in Table 2 and the following text are:

- Only synchronous generators and synchronous condensers provide synchronous inertia.
- The characteristics of service quantity across the technologies differs. Some are discontinuous and lumpy, while wind is stochastic.

- Many solutions have significant capital costs, and some have additional benefits, such as energy for generators, and arbitrage and peak-shaving for batteries.
- Batteries and synthetic inertia are currently evolving technologies.

Table 2 – Economic and Technical Characteristics of Technical Solutions

Technology	Description	Synch-ronous inertia?	Capital Intensive?	Cost to Supply RoCoF Management Service?	Characteristic of Service Quantity?	Ramp Time of RoCoF Management Service?
Synchronous Generator	A new or existing coal, gas, hydro or nuclear plant that provides inertia as a by-product of energy.	Yes	Yes, but free with existing plant, if plant is viable.	None, when producing energy Fuel cost to run at margins of operating period Large cost to bring up from cold	Discontinuous and lumpy – Fixed quantity for given plant, when operating above minimum level, zero otherwise	A few seconds (hydro) to many hours (coal)
Synchronous Condenser	A new or existing plant operating without load, providing a synchronised spinning mass.	Yes	Yes, to build new or convert existing generator	Cost of small energy consumption to keep spinning.	Discontinuous and lumpy – Fixed quantity for given plant, when operating, zero otherwise	< 15 mins
Synthetic Inertia for Wind Farm	Control equipment fitted to a wind turbine to extract inertial energy from spinning turbines.	No	Additional expense to new wind farm	Opportunity cost of derating	Stochastic – related to wind speed and turbine state	None, but depends on wind potential
Batteries	Energy storage able to respond rapidly with energy to a change in system frequency.	No	Yes, but may be split over multiple benefits.	Opportunity cost of arbitrageable energy.	Continuous and controllable	None, if sufficient charge is available.
Fast Interruptible Load	Large load configured to disconnect on high RoCoF.	No	No, except for control equipment	Probable costs to configure to allow load to be safely at risk.	Has steps based on settings of control equipment	As fast as the plant can be secured to enable interruption.

5.2.1 Synchronous Machines

60. Synchronous generators have a spinning component that is physically synchronous to the frequency of the power grid. These include hydro, coal, gas and nuclear. The quantity of inertia provided is fixed by the physical properties of the synchronous machine, and available only when operating. Many plants have a minimum energy output level, which can be reduced by retrofitting of new burners and other modifications[23]. Some plants (coal and nuclear) can take several hours to turn on.

61. The quantity of inertia supplied is therefore lumpy, and discontinuous relative to energy output, dependent on whether the generator is operating.

5.2.2 Synchronous Condenser

62. A synchronous condenser is a large rotor synchronised to the grid but not generating energy. It consumes a small amount of energy when providing the inertia service, between 1-4% of its output capacity[23]. A decommissioned thermal power station can be converted, at some situation-dependent cost, to a synchronous condenser. The synchronous condenser provides a fixed quantity of inertia if on, none if off. It can typically be started up in under 15 minutes[23].

63. A synchronous condenser has the advantage of providing a synchronous inertia response and also providing fault level and voltage support services that are useful to the power system, so it is likely to be valued for more than just its RoCoF management capabilities.

5.2.3 Wind Turbines – Synthetic Inertia

64. Many modern wind turbines (such as the common DFIG[18] type) have the rotating mass electronically decoupled from the power system so do not contribute an automatic inertial response. Control system equipment and software has recently evolved that is installed to give an emulated (or “synthetic”) inertia response[13]. There is a capital cost and potentially a small operating reduction in output [13]. The potential emulated inertia response is stochastic[43] so its effective contribution depends on system integration[19].

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[18] Doubly-fed Induction Generator

[19] A power system with a minimum-inertia requirement would demand that the synthetic inertia be able to meet its claimed contribution some large fraction of the time, meaning its effective contribution would be low compared to its average potential inertial response. Diversity may improve this.

65. Hydro Quebec has been installing such equipment since 2009. Evaluation of the technology in the field is ongoing, with the specific behaviour in the recovery phase, and the need to tune the response, found in 2013 to need more investigation[14].

5.2.4 Batteries

66. Batteries are able to rapidly inject power to counteract a system power imbalance. A battery may ramp up to 100% output in under a second[20]. Few-MW-scale frequency regulation services are currently provided commercially by GE and Ecoult[25] batteries.

67. Battery technology is a rapidly developing field, with ongoing research into battery chemistries and increasing efficiencies with production scale driving down costs, with investment banks predicting dramatic falls in price in the next 3 years[39]. Electric vehicles and electricity network services are two of the drivers of this development. Batteries are being increasingly installed in distribution networks in preference to traditional network augmentation[17], providing services such as peak-shaving.

68. A battery's ability to provide a contingency response will interact economically with other benefits it can provide, such as other contingency services and arbitraging energy. Lead-acid batteries, a well-established and inexpensive technology, may economically provide a standby response suitable for infrequent RoCoF contingency management, however they are not suited to frequent cycling so they would not provide other services.

5.2.5 Fast Interruptible Load

69. Large industrial loads fitted with appropriate equipment could disconnect rapidly when a high RoCoF event was detected, returning significant energy to the power system. Interruptible load tripped at a specified frequency currently participates in fast-raise reserve markets. For RoCoF management the trip point would need to be on RoCoF, not frequency level. Such loads are likely to require payment to put their loads at risk.

5.3 Bounds on Technical Solution Costs

70. It is useful to look at known options for bounds to the costs of RoCoF management, and to help determine if some technical solutions should be eliminated from consideration.

[20] GE budget 750mS to full power for an instruction from an external source[17].

71. As the number of hours of scarcity (and therefore value) increases, capital-intensive solutions become more economic compared to high variable-cost solutions. An upper bound is the cost of building it out with synchronous condensers, which are shown here to have the potential to be economic at moderate levels of RoCoF management scarcity.

72. A high variable-cost solution is to run an existing generator in hours where it would not otherwise be profitable to do so. For indicative comparison, a 450 MW combined-cycle gas turbine plant running at 40%[23] minimum load at 60% efficiency, gas price of $3.50/GJ[7] costs approximately A$4,000 an hour in fuel to run.

73. In 2013, Energinet.dk in Denmark purchased two 200 MVA synchronous condensers to support the high wind-penetration power system[21], in place of operating synchronous generators[49], at a cost of 340m DKK (A$68m[50]). Assuming an 8% carrying cost and a 30 year or more life, this is A$5.5m a year. If the synchronous condensers used 3%[23] of their rated power to operate, at an average price of $50/MWh[22], this is $600/hr.

74. Assuming that the plants provide similar levels of system services (inertia, voltage support, fault level)[23], the synchronous condenser costs $3,400 less an hour to operate. It pays for itself at 1,600 hours a year, about 20% of hours.

75. Indicative costings for other technologies are not provided here as they are difficult to obtain. Detailed work in Ireland[45], found there was significant uncertainty in the costs of provision of new ancillary services across a range of technologies. There is considerable uncertainty about the costs of battery technologies, which are predicted to fall rapidly in the near future[39].

6 Incentives for Stakeholders

76. AEMO has ultimate responsibility for ensuring power system security, supported by the policy and rule makers. This section identifies the economic incentives that other stakeholders face regarding RoCoF management, to inform the later analysis. Table 3

[21] Western Denmark had approximately 35% wind by capacity in 2011[24].
[22] Average energy price across the NEM in 2013-2014, from [8]. Note that if run infrequently, it would likely be in the lower-price hours where more renewables are running. In September 2014, the 10th percentile of SA power prices was $19[8].
[23] This is a significant simplifying assumption made for this order-of-magnitude comparison. The level of inertia supplied by the synchronous condenser depends on its construction.

analyses the interaction of the stakeholders, looking at how they contribute to the problem of a scarcity of RoCoF management services, what they can do to assist with its solution, and what would incentivise such action.

77. Points of particular interest in Table 3 are:

- Wind farms are not efficiently incentivised to solve the RoCoF management problem due its public good nature, and due to the displacement of wind energy by inertia-providing generators.
- Network Service Provider (NSP) incentives are very different to market participants'.
- Many parties (thermal and wind generators, NSPs, loads) can set the largest contingency size, each with different benefits and incentives.

Table 3 - Economic Analysis of Stakeholders in RoCoF Management Issues

Actor	Causer of RoCoF management issues?	What amelioration opportunities?	What are options to incentivise amelioration action?
Thermal Generator	-	Can contribute inertia at the margin of an operating period by not shutting down.	**Regulation** – emergency orders **Financial** – revenue from RoCoF management service revenue, sufficient to cover fuel costs and provide some profit.
		Contribute inertia by starting up only for inertia.	**Regulation** – emergency orders **Financial** –RoCoF management service revenue, sufficient to cover fuel costs, significant start-up costs and slow ramp time, and provide some profit.
		Convert to a synchronous condenser to provide system inertia.	**Financial** – if unprofitable as a generator, and RoCoF service revenue is available to cover fixed costs of conversion and running costs of synchronous condenser, and provide some profit.
	Typically has large contingency size.	Run at a lower output level.	**Regulation** – by ordering dispatch to a lower level. **Financial** – by exposure to RoCoF management costs related to contingency size.
Hydro Generator	-	Contribute system inertia whenever operational, with a typically low minimum level of operation.	**Regulation** – emergency orders. **Financial** –RoCoF management service revenue, which needs to cover use of water, which may be preferentially stored for use at high-price times.

Actor	Causer of RoCoF management issues?	What amelioration opportunities?	What are options to incentivise amelioration action?
Wind Generator **(also applicable to large-scale PV)**	Increases risk of low system inertia, by not contributing conventional share.	Install synthetic-inertia control equipment (specific to wind)	**Regulation** – in connection standards. **Financial** – by RoCoF management service revenue that covers the extra capital and running costs of synthetic inertia equipment, and provide some profit.
		Procure RoCoF management services that do not displace wind/PV energy[24].	**Financial** – incentivised to decrease curtailment due to energy displacement by thermal or hydro plant. Renewable-energy payments give extra incentive. However, RoCoF management services are a public good so individual plant owners will not face efficient incentives.
	Contingency risk from having radial feeder.	More network redundancy.	**Regulation** – of maximum contingency size on a radial feeder. **Financial** – by exposure to RoCoF management costs related to contingency size.
Transmission Network Service Provider	Yes, of contingency risk from large interconnectors.	Consider RoCoF management costs when expanding interconnectors.	**Financial** – a RIT-T case to AER to expand an interconnector should consider the RoCoF management cost impacts. **Financial** – by exposure to RoCoF management costs related to contingency size. As an expense it may be passed directly to consumers with little impact on the NSP. A regulatory incentive scheme could consider these costs, to incentivise the NSP.
	Yes, may influence outages that make RoCoF management temporarily harder.	Carefully time maintenance, and perform sufficient maintenance to reduce outages.	**Financial** – incentivised in a limited way by market-impact and network-service incentive schemes
	-	Can efficiently own and manage grid-level equipment such as batteries and synchronous condensers that supply inertia services.	**Regulation** – on direction from the system operator. **Financial** – need to make a RIT-T case to AER to expand the asset base. Could evidence high costs in RoCoF management service market but would not typically compete directly in market.

[24] Curtailment of wind output at times of low system inertia is a concern for wind generators. It is important to understand that the actual curtailment is not caused by increased wind increasing inertia requirements, but by the load being so low that the wind output plus the minimum (or ramp-constrained) output of committed thermal plants exceeds the load. Some of these thermal plants may be operating in order to secure the power system against low inertia. A wind generator has no incentive to contract with a thermal plant to provide system inertia at such times, as its operation would further displace the wind output. The wind generators are incentivised to seek other sources of system inertia that do not displace their output, or which displace it less, which may not be the least-cost way of sourcing the RoCoF management the system needs.

Actor	Causer of RoCoF management issues?	What amelioration opportunities?	What are options to incentivise amelioration action?
Loads	Yes, of large contingency (over-frequency direction), but typically smaller than generators.	Set up automatic generator unloading on tripping	**Regulation** – if required to provide unloading contract **Financial** – by exposure to RoCoF management costs
	-	Offer significant fast interruptible load	**Financial** – where RoCoF service payments for interruptible load outweigh loss from potential for interruption, and cover capital costs of control equipment.
Entrepreneur	-	Could purchase and install batteries or synchronous condensers to provide an inertia service.	**Financial** – where expected operating profit from a RoCoF service market covered capital and operating costs. For a battery this is considered in combination with other services from the battery.
Government / Reliability Panel	The requirement for particular frequency control standards.	A looser frequency control standard would allow less RoCoF management service to be sourced and/or higher contingencies managed, traded for a marginal increase in the impact of frequency fluctuations on the performance of some connected equipment.	**Financial** – overall lower electricity bills for consumers.

7 Construction of Analysis Framework

78. This section develops a framework for economic and policy analysis to answer the question “What is the best option for RoCoF management?”. The National Electricity Objective, the philosophy of the National Electricity Rules and principles of best practice regulation are used to form the objective and the assessment criteria. Table 4 lists these criteria.

Table 4 - Option Assessment Criteria

Criterion	Details	Reference
Productive Efficiency	The option should promote selection of RoCoF management services that in combination provide the highest net economic benefit.	Productive efficiency to meet objective, paragraph 90
Allocative Efficiency	The option should take account of both the costs and benefits of RoCoF management services, and incentivise both suppliers and beneficiaries to reveal their costs and benefits.	Allocative efficiency to meet objective, paragraph 91
Dynamic Efficiency	The option should incentivise, and embed flexibility to incorporate, technological advances and innovations, and should not bias a particular technological solution.	Dynamic efficiency to meet objective, paragraph 92
Confidence in Deliverability	An option should provide an appropriate level of confidence that it will deliver the required RoCoF management for power system security.	Confidence in deliverability to meet objective, paragraph 94
Workability and Robustness	The option must be workable in a practical sense, and robust to future market and technology developments.	Establish a regulatory commitment to meet objective, paragraph 99
Proportionality	The cost and complexity of market and regulatory measures required by the option should be in proportion to the net benefits the option is likely to deliver.	Good regulatory design principle of proportionality, paragraph 102
Consistency	The option should fit in a consistent manner into the complex existing markets and regulatory systems.	Good regulatory design for seamless and consistent incentives, paragraph 101
Minimum of Market Intervention	An option incorporating a market should allow that market to operate, and continue operating, with minimum intervention.	Market design principle of minimum-intervention, paragraph 98

7.1 Objective of the Options

79. The objective of the potential options on the RoCoF management problem is developed from the National Electricity Objective, analysed in detail below.

80. The objective of the options assessed in this report is to:

> *in the context of increasing penetration of renewables, promote efficient investment in, and efficient operation of, services that contribute to the management of the Rate of Change of Frequency, for the long term interests of consumers of electricity, with respect to the RoCoF aspect of security of supply, price and quality of electricity.*

81. Prior to the increasing penetration of renewables, efficient investment and operation were achieved by the incumbent generators providing ample system inertia at zero cost.

7.1.1 National Electricity Objective

82. In the National Electricity Law[32], the overarching regulatory instrument for the National Electricity Market, the National Electricity Objective is stated in section 7 as:

> *The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to –*
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
> *(b) the reliability, safety and security of the national electricity system*

83. Price, quality and security of supply are relevant to RoCoF management.

84. Price is relevant as improving RoCoF management should have a net societal benefit.

85. The quality of the system frequency is of value to some consumers. The frequency operating standards were set historically, and in the context of increasing renewables penetration, may no longer provide an efficient match between consumer benefit and the increasing cost of frequency management, including RoCoF management.

86. Security of supply[3] is highly relevant as it defines the need to continue operating within technical limits after a contingency event, which requires, among other things, sufficient RoCoF management. The ability of conventional synchronous plant to efficiently supply most of the RoCoF management needed to maintain security of supply is challenged by increasing penetration of non-synchronous renewables.

87. Reliability is not relevant to this analysis as RoCoF management is concerned with the immediate effects of a disturbance, not the ongoing supply of electricity.

7.2 Economic Principles Relevant to the Objective

88. The economic principles of productive, allocative and dynamic efficiency are discussed here in detail as the understanding of each helps inform thinking about the different types of instruments to address the RoCoF management issues. The issue is more than

simply sourcing system inertia most cheaply. It is important to also appreciate the emerging cost drivers as the costs of sourcing system inertia increase. Additionally, in a changing environment there is some level of need for confidence in deliverability of the desired RoCoF management levels, so that the theoretical economic efficiency properties of the option can be realised.

7.2.1 Economic Meaning of National Electricity Objective

89. Based on work by an expert economist[46] on the National Gas Objective (NGO), similarly-worded to the NEO, the RoCoF management interpretation of the NEO means in an economic sense:

- **'efficient investment in, and efficient operation and use of'** covers productive, dynamic and allocative economic efficiency, outcomes expected in a workably competitive market over the long run.
- **Productive (or technical) efficiency** means that RoCoF management services, where required, are produced at minimum cost, using the least-cost combination of inputs, using technology and knowledge at that point in time.
- **Allocative efficiency** means that the right amounts of the right types of RoCoF management services are produced and consumed. Price structures and levels that encourage efficient use of the services is important.
- **Dynamic efficiency** means that allocative and productive efficiency continues to be achieved over time. The ability to adapt to changes in technology and in consumer needs and to innovate, and the existence of incentives to do so, are important.

7.2.2 Relevance of Economic Efficiency to RoCoF Management

90. Productive efficiency is relevant in determining how to efficiently combine the different types of RoCoF management services to give the required level of RoCoF management[25].

91. Allocative efficiency is relevant in ensuring the right amount of RoCoF management is provided for the value it creates. Allocatively efficient RoCoF management needs to consider the benefits of high frequency quality, the market benefits of a large maximum

[25] Note it is currently consistent with productive efficiency in most of the NEM (excluding SA & TAS) to ignore RoCoF management issues given the high quantity of system inertia typically available.

contingency size and the market benefits of enabling cheap renewable generation to be reliably dispatched.

92. Dynamic efficiency is relevant in allowing the RoCoF management systems to adapt and improve given changes in the generation mix, particularly the potential exit of thermal plants, and rapid developments in renewable and storage technologies.

93. Note that the NEO limits the types of benefit that may be considered to only those that relate directly to the provision and consumption of electricity, ignoring externalities such as environmental benefits from dispatching more low-carbon electricity[26].

7.2.3 Need for Confidence in Deliverability

94. An option may fail to achieve the RoCoF management outcomes that the system operator requires in the timeframe it is needed, due to problems with the technology, a market taking time to operate effectively[27], or a market failure. The level of confidence in deliverability of an option gives a measure of this risk to the system operator.

95. If the required RoCoF management is not obtained, security of supply is at risk, so load-shedding may result or the operator may issue emergency orders. If frequent, these can become significantly economically inefficient, reducing the success of the option in supporting the objective, regardless of its inherent economic efficiency properties.

96. The relative importance of this criterion compared to the economic efficiency criteria depends on the scale of the load-shedding cost and the inefficiency of emergency orders, and the timeframe in which they are becoming significantly material.

7.3 Best Practice Economic and Regulatory Principles

97. Further relevant criteria are found in the philosophy of the National Electricity Rules and in principles of Best Practice Regulation.

7.3.1 National Electricity Rules Philosophy

98. Section 3.1.4 of the National Electricity Rules[2] provides the market design principles for the wholesale and ancillary services markets of the NEM, which were designed to

[26] The separate MRET (Mandatory Renewable Energy Target) scheme incentivises investment in low-carbon electricity. Where a carbon price exists, the "price" component of the objective will capture environmental benefits.

[27] which is particularly an issue where capital investment by participants is required

meet the National Electricity Objective. Most relevant is that a “market design should minimise decision-making by the system operator”[28]. This is particularly relevant to the RoCoF management issue where the system operator has a system security obligation but not a policy role.

7.3.2 Regulatory Commitment

99. The expert economist[46], in looking at principles for models to meet the National Gas Objective, which is very similar in intent to the National Electricity Objective, states that a model should establish a regulatory commitment to encourage efficient long-term investment. This means that the model must be sufficiently workable and robust to provide certainty for participants about its longevity.

7.3.3 Good Regulatory Design

100. Good regulatory design principles describe how amended market rules or regulatory arrangements that give effect to the RoCoF management options should perform.

101. Good regulatory design requires the creation of seamless and consistent incentives, where interactions between new and existing markets and regulations do not create incentives that act against the objectives. This is outlined in Section 3.2.15 of [33]. The provision of RoCoF management services may impact (positively or negatively) on a participant’s ability and incentive to provide other energy or ancillary services.

102. A regulatory intervention or new market design will impose costs and administrative burdens on participants and the system operator. Good regulatory design requires that such impacts are proportionate to the scale of the issue being addressed and the net benefits of addressing it, according to Section 2 in [37].

8 Indicative Analysis and Evaluation of Options

103. This section looks at the economic properties of potential options to contribute to the objective developed in Section 5, and assesses how they meet the developed assessment

[28] Section 2.4 of Appendix 1 of [30] explains that the operator’s decision-making is to be minimised so that the market result is what the competitive market would find itself given sufficient time and information to do so. A central market-clearing process facilitates this but should interfere as little as possible with the outcome. Section 3.4(d) explains that while the operator has a responsibility to secure the system, it must limit its interventions to a minimum to prevent market collapse due to reliance on the provision of services by the monopoly operator.

criteria. The evaluation is an indicative assessment only, as each option requires substantial further work to fully explore it.

104. The options are described and assessed in the context of the NEM market design and regulatory frameworks, but with current market conditions and local issues not discussed in this section. The options are derived from extensions to existing regulatory and market frameworks and from considering the incentives for action by stakeholders examined in Section 6. Technical approaches are taken from [5].

8.1 Identification and Application of Best Options

105. This section discusses how the individual options fit together into a RoCoF management plan and presents a framework for identifying which option or options are likely to be the best choice for a given scenario.

8.1.1 Application of Options

106. The options being assessed are not single solutions to the RoCoF management problem. In specific scenarios different combinations of options will best address the objective defined in Section 7, with the word "better" meaning "better at addressing the objective". A single option does not have to cover all of RoCoF management. A combination of a near-term central-planning option with a longer-term market plan may effectively address an urgent system security need today and a highly material problem tomorrow.

107. As discussed in paragraph 31, a minimum level of specifically synchronous inertia may be required. This could be addressed consistently with broader RoCoF management services using some combination of regulatory and/or market options, or a market with multiple services defined.

8.1.2 Options of Value in Any Scenario

108. It is of value to the system to discourage investment in large contingencies that will drive excessive cost now or in future. Regulation of maximum contingency size (Section 8.4.5) is relevant in any scenario where RoCoF management costs are emerging. In a market approach, this discouragement may be achieved indirectly through causer-pays approaches and/or real-time curtailment (Section 8.5).

109. In any scenario, defining a power system RoCoF standard (Section 8.3.2) provides a basis for workability of all the other options. As RoCoF management costs (and/or other frequency management costs) increase, a review of frequency operating standards (Section 8.3.1) is justifiable.

8.1.3 Identification of Best Option for Scenario

110. Figure 4 compares the analysed options in a simplified graphical manner. The vertical axis plots the need for confidence in deliverability (Section 7.2.3), which is most dependent on the urgency of the problem. The horizontal axis plots the materiality of the RoCoF management problem. This incorporates the emerging RoCoF management costs and the value of foregone benefits due to a RoCoF management service shortage.

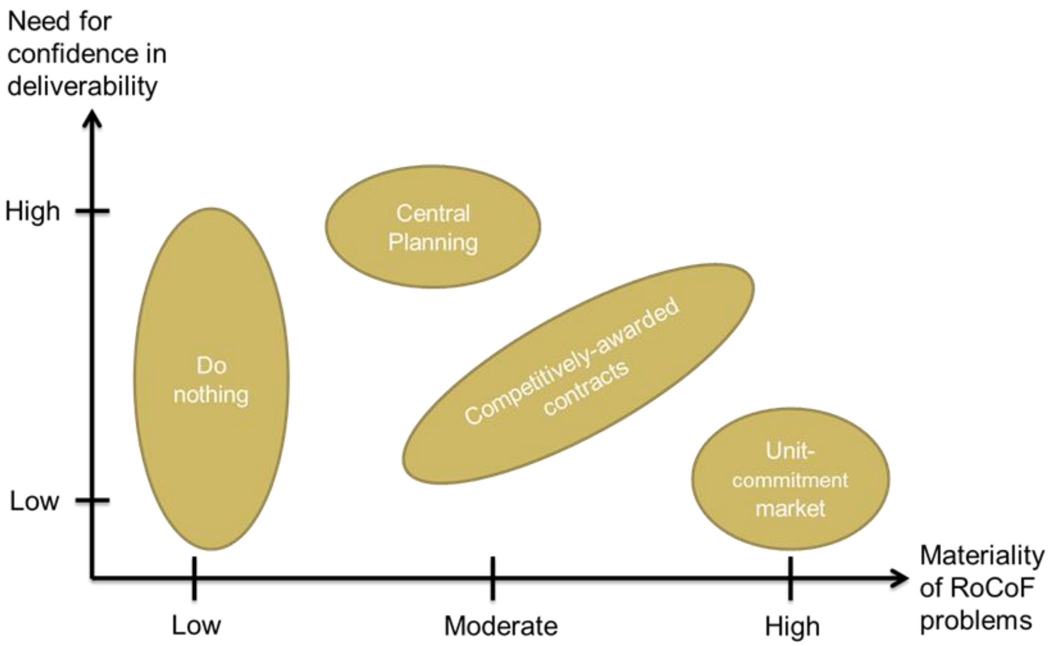

Figure 4 – Best Option by Certainty Requirement and Materiality - Today

111. In words, Figure 4 expresses:

- “Do nothing” best meets the objectives when materiality is low (Section 8.2).
- A central planning approach (one or more options from Section 8.4) best meets the objectives when the need for confidence in deliverability is high, but as materiality increases, the economic efficiency downsides become more significant.
- A unit-commitment market approach (Section 8.5.2) provides low confidence in deliverability today. As the materiality of the problem increases, the economic efficiency benefits of a co-optimised market may outweigh the co-ordination costs.

- A competitively-awarded contracts approach (Section 8.5.1) sits in the middle of central planning and unit-commitment market on both confidence in deliverability and economic efficiency.

112. The position and size of the space where each option is best in Figure 4 is indicative only, and subject to uncertainty. The relative ranking of the options may change as the technology and markets evolve, and as more is learnt about specific options. Two alternative future scenarios are discussed in Section 8.6 following the detailed analysis.

8.2 The "Do-Nothing" Option

113. Best practice regulation principles require always considering the "do nothing" option. As the RoCoF management problem emerges, there isn't a "do absolutely nothing" scenario as the system operator must ensure power system security. The operator may use emergency powers to direct synchronous generator operation and/or may add a constraint to the dispatch to specify a minimum level of system inertia, curtailing non-synchronous generation (such as wind or PV) to achieve this[5]. Gaming may be an issue if this interacts with self-commitment decisions.

114. This do-almost-nothing option supports the objective on the basis of **proportionality**, without significant impact on **economic efficiency,** if the incidence of low inertia is infrequent, the economic cost of curtailment is low and thermal plants are available to run. In general, these will be when the materiality of the problem is low.

115. This do-almost-nothing option becomes **unworkable** if a material number of synchronous plants exit the energy market.

8.3 Frequency Standard Review Options

116. The "quality" and "security of supply" factors of the objective are driven by the power system targets for post-contingency frequency excursion and for RoCoF. Quantifying the costs and benefits of these targets is difficult, and it is not practical to price or vary these in real time given that emergency protection equipment needs to be configured with frequency and RoCoF trip settings. A regulatory, rather than market, approach is therefore appropriate.

8.3.1 Review Frequency Operating Standards

117. Frequency operating standards are reviewed infrequently, and on an incremental basis, as total value of consumer benefit for different ranges is difficult to estimate[36].

118. Conducting a review promotes **allocative efficiency** by attempting to match the marginal costs of frequency control to the marginal benefits to consumers (the "quality"). Considering **proportionality**, a review of frequency operating standards could be justified by the emerging value of RoCoF management services.

8.3.2 Define a Power System RoCoF Standard

119. There are currently no power system performance requirements for maximum RoCoF in case of contingency events in the NEM. There is complex set of factors affecting the RoCoF target for power system operation, which include the frequency operating bands, connection standards, and known RoCoF tolerance and settings of existing generation and under-frequency relays[5][29]. In Ireland, the RoCoF protection relays are proposed to be changed from 0.5 Hz/s to 1 Hz/s to allow the RoCoF targets to be relaxed[27].

120. A RoCoF target provides role clarity[30] in what level of RoCoF management the system operator needs to achieve by a market or regulatory arrangements and what it may protect against using emergency measures.

121. Defining in regulation a RoCoF target would make the RoCoF management more **workable** for the system operator. It would provide a basis for the workability of the other market and regulatory options discussed here. The RoCoF limit defines a cost driver, so **allocative efficiency** is promoted by careful setting of its level to balance costs and benefits to security of supply.

8.4 Central Planning Options

122. A central planning option is one where a decision-maker decides centrally how the RoCoF management will be achieved. This may include determining the technology solution or directing by regulation the behaviour of participants. These options build on existing regulatory frameworks in the NEM.

[29] See also Section 3.2
[30] Role clarity is an important principle in best-practice regulation[38].

123. For each of these options, **confidence in deliverability** in achieving the security of supply obligations is the main benefit. **Proportionality** is promoted by options with simple regulatory arrangements, being simpler to implement and operate than a complex market. However, **proportionality** is only promoted where the technical solution imposed is competitive in system cost with other options. This may be hard or impossible to demonstrate in advance.

124. Economic efficiency is challenged by the inherent inability of a central planner to collect all information to make the best decisions, given a lack of incentives for participants to reveal true costs and benefits. **Productive efficiency** is challenged if the decision maker decides which technologies to promote or operate, and **allocative efficiency** is challenged by central decisions on the quantity of system inertia to seek. **Dynamic efficiency** is inhibited by a lack of incentives for participants to innovate and by the slow pace of regulatory change. Central planning is at odds with the energy market philosophy of **minimum market intervention**.

125. Table 5 details under what circumstances such an option can support the objective. Further notes on each option follows. Further research is indicated to technically and financially quantify each of these options.

Table 5 - Assessment of Central Planning Options

Option	Regulation	Supports Objective If
Prohibit the Connection of Non-Synchronous Generation	Generation that does not inherently provide synchronous inertia is banned in connection standards.	RoCoF management issues are urgent and time is needed to develop a solution. or A low-cost technical solution is found in the near future. or The system costs of accommodating non-synchronous new generation outweigh the benefits over time[31].
Mandated Connection Standards (Grid Codes)	Connection standards add a regulation that all new connections are required to provide a specified frequency response. This is particularly applicable to wind farms with synthetic inertia technology.	The level of frequency response required balances significant upfront costs with increasing future benefits. The technical solution is feasible and of competitive cost as a system solution. The standards are robust and adaptable to a range of technologies and to future technology changes.

[31] This point is included for completeness, noting that it would be difficult to determine given its scope and complexity and the pace of change in renewable technologies and environmental issues.

Option	Regulation	Supports Objective If
Centrally Build-It-Out	Networks are approved to build out the problem by installing large-scale devices to supply the system inertia needs, for example through a RIT-T[32] process.	A capital-intensive, increasing-returns-to-scale technical solution gives the highest net system benefit. The decisions to approve the equipment can be made quickly enough to be relevant.
Mandate Participation by New Low-Cost RoCoF Management Sources	New RoCoF management sources, such as EV batteries, include in their standards a RoCoF management capability.	Effective co-ordination of the RoCoF management is workable. A very-low cost technology exists and is of sufficient penetration to address the problem. The regulation is robust to technology changes.
Regulate Maximum Contingency Sizes	Connection standards and network design rules add regulations on the maximum size of contingency elements.	The trade-off between contingency size and net system benefit can be determined, such as if there is a clear jump in RoCoF management costs at some contingency size. There is a mechanism to review these limits as costs evolve.

8.4.1 Prohibit the Connection of Non-Synchronous Generation

126. Prohibiting additional connections provides very high **confidence in deliverability** of the outcome by immediately preventing the problem from worsening. Such a moratorium was seen in Ireland in 2004[48], done to buy time to work out how to maintain power system security with increasing wind penetration.

127. This option might ultimately promote **dynamic efficiency** by delaying a decision on how to best solve RoCoF problems until technological advances make obvious the best approach. Excessive expense on equipment that became obsolete could be avoided. However, there is no guarantee of this outcome.

8.4.2 Implement Mandated Connection Standards (Grid Codes)

128. In this option, connection standards add a regulation that all new connections are required to provide a specified frequency response. This option is particularly applicable to wind farms suitable for synthetic inertia technology. A connection standard has the potential to **consistently** address RoCoF management alongside other system frequency control requirements.

32 Regulatory Investment Test for Transmission, where a TNSP applies to the AER for approval to invest to increase its regulated asset base for a particular purpose.

129. A grid code will, if the technology is sufficiently low-cost, provide a regulatory incentive for all participants to contribute to the public good of RoCoF management. Determining the level of response required is a difficult **allocative efficiency** question. A RoCoF management requirement is the first step, and then to determine how much response is needed, now and across the life of the plants, to meet the system requirement.

130. Having wind farms contribute to RoCoF management when operational addresses the problem of displacement of synchronous plants by wind dispatch. However, demanding enough RoCoF management capability for secure operation in near 100% wind situations may leave the system massively oversupplied for a large part of the time when relatively high-inertia thermal plants are still operating.

131. The careful design of such a scheme could increase the promotion of the objectives. Including in the connection standard the ability to supply the obligated response from an alternative technology, or a different plant, could improve **productive** and **dynamic efficiency**.

8.4.3 Centrally Build-Out the Issue

132. A TNSP may be able to install, or make use of existing, large-scale batteries and synchronous condensers to supply RoCoF management. The application of the RIT-T would need to find such solution to be of most benefit to consumers, from the options available.

8.4.4 Mandate Participation by New Low-Cost RoCoF Management Sources

133. In this option, RoCoF management service sources include in their technical standards the requirement to provide a RoCoF management capability. This option requires the appropriate technology to exist before it can apply. Widespread distribution-connection electric-vehicle (EV) batteries is a candidate. **Workability** would be an issue if the ability to provide the service at very low cost differed between products in the class or at different times of the day or year.

8.4.5 Regulate Maximum Contingency Sizes

134. Limiting maximum contingency sizes by regulation to reduce inefficient expenditure on RoCoF management supports **allocative efficiency**, but only if the contingency size

benefit can be determined. This is likely to be easier for a single-feeder wind farm or large load proposal than for a large interconnector.

8.5 Competitive Market Approaches

135. Economic theory holds that a workably competitive market incentivises participants to make good decisions and to be adaptable. **Productive efficiency** is promoted by a market that incentivises the lowest-cost services to be revealed and selected. **Allocative efficiency** is promoted by a market that provides price signals that reveal the benefits of the services. **Dynamic efficiency** is promoted by price signals that reward innovative behaviour and encourage efficient entry and exit.

136. **Dynamic efficiency** of a market is supported by infra-marginal rents[33] that can provide efficient incentives for long-term capital investment. Market-clearing (as opposed to pay-as-bid) pricing delivers such rents. Market-clearing pricing also encourages true costs to be revealed and rewards innovation and investment that reduces costs.

137. The **confidence in deliverability** given by a market solution at the current time may be lower than that of a centrally-planned solution, in that it may take time for market participants to enter and establish the best outcomes, especially if capital investment is needed, as it is for some RoCoF management solutions.

138. Building on the existing competitive market frameworks in the NEM, two forms of market are examined here – a competitively-awarded contract approach and a centralised market-clearing dispatch approach.

8.5.1 Competitively-Awarded Contract Option

139. A competitively-awarded contract approach is discussed here at a high level, along with market design considerations relevant to RoCoF management. Further research is indicated into the most suitable contract design. The system operator would determine the quantity of RoCoF management services required and source these by periodic competitive tender or auction.

[33] When a service is paid at a market-clearing price, typically the marginal short-run price, some suppliers will receive more than their total short-run costs. This surplus is termed the "infra-marginal rent". It incentivises high capital-cost but low short-run marginal-cost suppliers to compete with low capital-cost, high short-run marginal-cost suppliers to find the optimal long-term combination of suppliers.

140. Compared to a complex centralised dispatch market, a forward contract market provides more **confidence in deliverability** at the current time. **Proportionality** is promoted by a straightforward contracting process.

141. The **allocative efficiency** is challenged as the level of RoCoF management service provision is set by the system operator, as real-time optimisation of the maximum contingency size and other frequency control ancillary service cost drivers is not feasible.

142. Maximum contingency size directly drives the quantity of RoCoF management required. A causer-pays approach, that apportions RoCoF management costs in some way based on contingency size[34], would promote **allocative efficiency** by incentivising reduction of inefficiently large contingencies[35].

143. The use of a market-clearing price for these contracts incentivises true costs to be bid and provides infra-marginal rents to incentivise efficient capital investment, promoting **dynamic efficiency**.

144. The contract design should consider whether the operator needs to dispatch the services. Given the temporal variability with dispatch conditions in the scarcity of RoCoF management services, a call option or similar is a likely contract component. It would be poor for **allocative efficiency** to instead be running plants at some cost on a must-run contract when there is ample inertia from synchronous plants dispatched for energy. As thermal plant provide inertia for free whenever operating and self-commit to the energy market, a perverse incentive may exist to withhold their self-commitment to force a trigger on RoCoF management service dispatch. This would be reduced if the contract was for an obligation to run at low inertia times, for an upfront payment, rather than a pure dispatch payment.

145. Long contract lengths (e.g. several years), while providing certainty for capital investment, may lock-in inefficient technologies or firms, reducing **dynamic efficiency**, and go against the philosophy of **minimum market intervention**. A shorter-term contract would allow each participant to reveal more accurately their ability and

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[34] Such as a "runway" model where the largest contingency pays the step from the next-largest, largest and second-largest share the next step, and so on[19], as used for reserves in Singapore.

[35] This also follows the NEM market philosophy of allocating where possible charges for ancillary services to incentivise lowered overall costs of the NEM.

willingness to provide RoCoF management services, which may depend on their intended participation in the energy markets.

146. The SEM in Ireland and Northern Ireland has proposed a competitively-awarded contract procurement mechanism for a new set of ancillary services. The services include synchronous inertia and a fast-frequency response service, both targeted at RoCoF management[45]. The proposal is for a combinatorial auction where each bidder may offer a set of mutually-exclusive bids covering combinations of services it is willing to provide, which are then evaluated to find an overall lowest-cost solution, with a market-clearing fixed price found for each service.

8.5.2 Unit-Commitment Market Option

147. This option defines a new service (or services) "synchronous inertia" and/or "fast frequency response" or similar, additional to existing market frequency control ancillary services[36]. The centrally-optimised dispatch is extended to dispatch and price these services along with the existing frequency ancillary services in a co-optimisation process. The process of co-optimised dispatch simultaneously optimises and prices the energy and ancillary service markets for maximum overall market benefit[37].

148. The existing NEM dispatch engine cannot optimise the dispatch of the synchronous inertia component of RoCoF management services. Synchronous plants provide a fixed level of system inertia while operating above some minimum energy output and zero when off. This means the inertia offer (relating reserve quantity, energy quantity, and offer price) is discontinuous, and depends on unit commitment, not energy quantity. Whenever inertia is scarce but energy is not, the optimal solution is for the plant to be dispatched at its minimum level, which is at the discontinuity. It is mathematically infeasible to form and solve such offers efficiently in a linear-program (LP) dispatch engine[38], such as that used in the NEM.

[36] Note that New Zealand has an "instantaneous reserve" service, but it is not actually instantaneous in the sense that synchronous inertia is. Synchronous inertia (the physical response) is specifically excluded from compensation in NZ's instantaneous reserve market[47]. NZ's instantaneous reserve covers a 6-second response from partially-loaded spinning reserve and tail-water-depressed hydro, and a 1s response from detection of a 49.2 Hz underfrequency event for interruptible load.
[37] See [41] for a detailed introduction to co-optimised markets.
[38] as confirmed in a conversation with Dr Brendan Ring, Director, Market Reform[42].

149. An alternative approach, which is examined here, is to develop a forward (such as day-ahead) unit-commitment optimisation. Such markets exist in North America, where typically a day-ahead multi-period unit-commitment optimisation is run with a mixed-integer program solver[39], followed by a real-time economic dispatch[28]. In this report, the shorthand "unit-commitment market" is used to refer to such a market.

150. Ela et al[28] outline a market design for primary frequency response which includes separate, but somewhat interchangeable, market services for synchronous inertia and several RoCoF-related services, in the context of a market with unit-commitment optimisation. This study found that a synchronous inertia service market could be optimally solved, but would always have a zero marginal price.

151. A modification to the unit-commitment optimisation algorithm is suggested in [28] that gives a price to incentivise the provision of synchronous inertia. In ERCOT in Texas, an SIR (Synchronous Inertia Reserve) and FFR (Fast Frequency Reserve) are proposed to be added to its existing real-time centrally-dispatched market with RUC (Reliability Unit Commitment) daily optimisation[29, 35]. The pricing of the SIR service is noted to be difficult in [29]. **Dynamic efficiency** is best promoted by appropriate price incentives. Determining how to find such prices consistent with dispatch is an important part of the development of such a market.

152. The centralised co-optimised dispatch approach has the key advantage of being **consistent** with NEM market design principles of central dispatch pricing and **minimum operator intervention**, and **consistent** with existing frequency ancillary service markets. Co-optimising against other frequency ancillary services promotes **allocative efficiency**. It is theoretically possible[40] to temporally co-optimise the maximum contingency size with the cost of the RoCoF management services, further promoting **allocative efficiency**. The magnitude of the benefits from doing these optimisations depends on how much system benefit comes from having large contingency sizes[41] and how much benefit there is in dynamically substituting RoCoF management for other

[39] A mixed-integer program solver solves optimisation problems that include integer variables and constraints, modelling for example whether a plant is on or off.
[40] The co-optimisation of frequency ancillary services against maximum contingency size is done at dispatch in New Zealand[40] and Singapore[42].
[41] Such as where a large interconnector allows cheap energy to be served across a larger area

(such as fast-raise) services. These benefits are likely to increase as the materiality of the problem increases.

153. The NEM currently has no day-ahead market, no unit-commitment dispatch engine and a self-commitment process. This gives low **confidence in deliverability** of RoCoF management under this option in the short- to medium-term. The costs of implementing such changes would be significant. For **proportionality**, these co-ordination costs need to be considered against the benefits. In the long term, and in combination with other power system security issues, these may be justifiable. As an aside, note that the original design for the Victorian market[30] in 1994 described a day-ahead unit-commitment optimisation, but it was not implemented given the almost exclusively synchronous generation at the time.

154. Co-optimised spot markets for frequency control ancillary services typically develop significant revenue from their links to energy prices, when compensating the opportunity costs of providing reserves instead of energy[41]. RoCoF management services, with the possible exception of batteries, do not have these energy-price-linked opportunity costs. It is a complex question, requiring further investigation and modelling, whether a spot and day-ahead market can develop enough revenue to efficiently incentivise the continued operation of synchronous plants and investment in new RoCoF management technologies.

155. Research into the actual costs and methods of implementation of a unit-commitment market, and into the likely market outcomes, would increase the **confidence in deliverability** of this option for some future time.

8.6 Future Uncertainty of Option Ranking

156. Figure 5 and Figure 6 contrast two future technology scenarios as a variation on Figure 4. Figure 5 shows where a specific central planning option (such as the EV battery idea in Section 8.4.4) emerges as such a cheap solution that its benefits outweigh the costs from its inherent economic inefficiencies, making it the best option over a larger space. Figure 6 shows where successful R&D has been done on the technical implementation and likely outcomes of a unit-commitment market, making the level of confidence in deliverability higher, and so increasing the space where it is the best option.

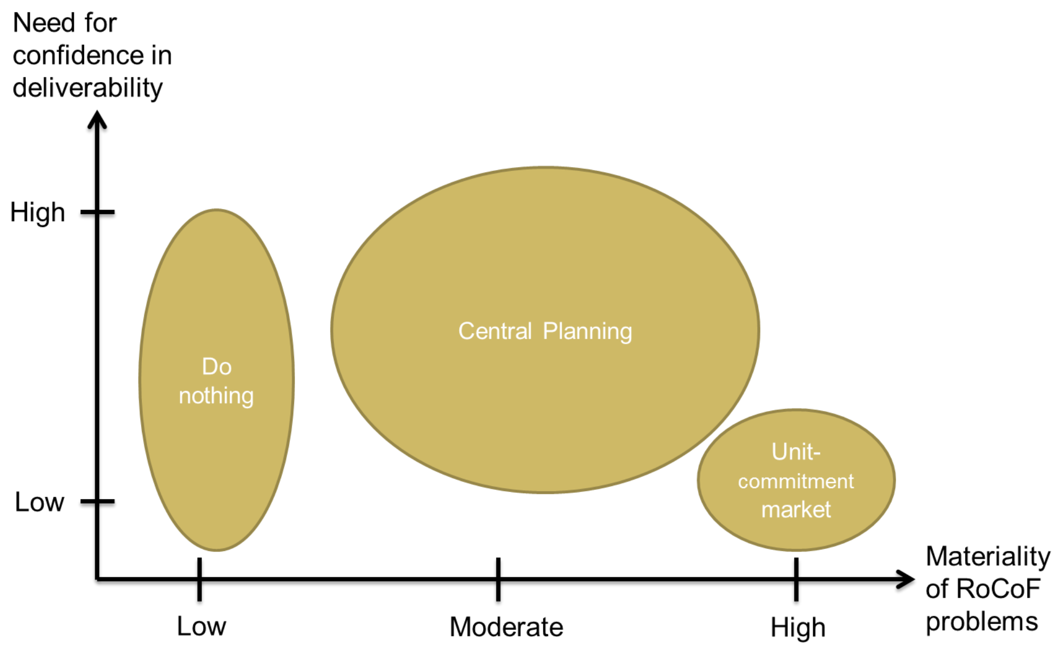

Figure 5 – Best Option by Confidence in Deliverability Need and Materiality – Specific Central Plan

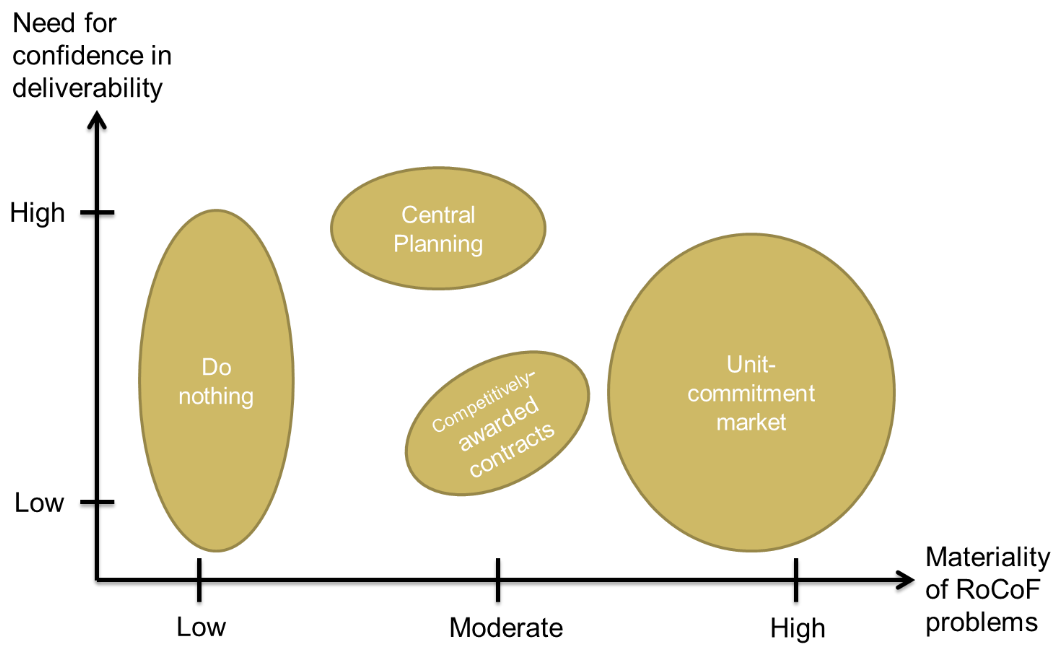

Figure 6 - Best Option by Confidence in Deliverability Need and Materiality - UC market developed

157. A significant conclusion from this analysis is that it is difficult to determine a good policy trajectory over time. Development of a decision-making process to manage the portfolio of emerging options in a rapidly evolving energy market is indicated as useful future work.

9 Practical Application of Options in the NEM

158. Modelling done by AEMO in [5] found that RoCoF management would be a substantial issue in Tasmania and South Australia by 2020. Competitively-awarded contracts, or combination of competitively-awarded contracts and a central-planning option are recommended in the near term, with a unit-commitment market recommended for the longer term, with R&D to start soon. A number of practical implementation issues need to be considered.

9.1 Indicative Recommendations for NEM Scenarios

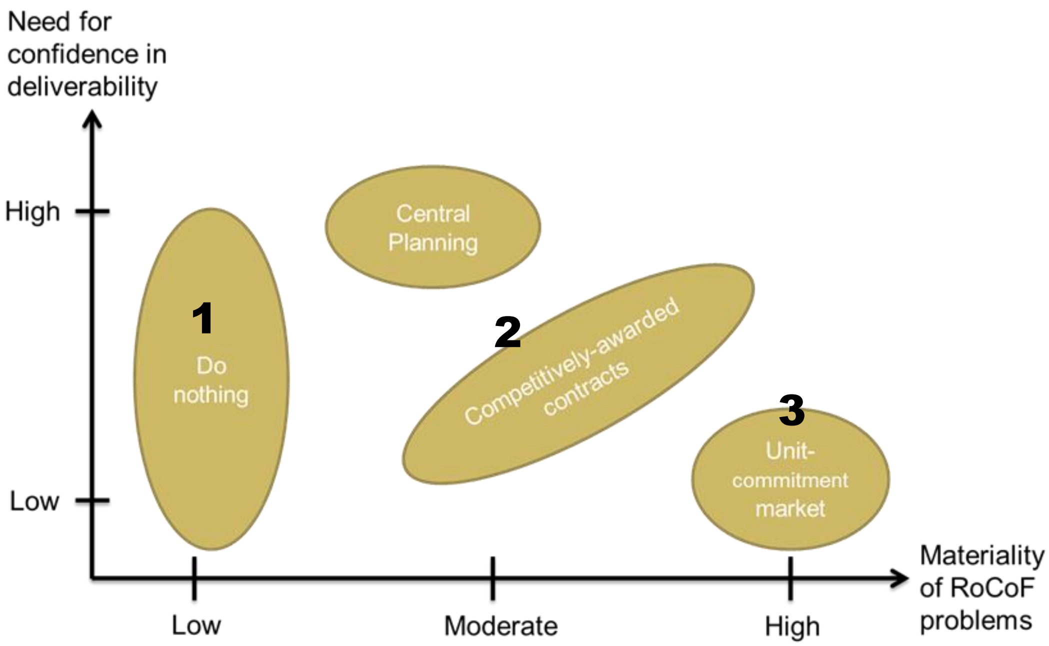

Figure 7 - NEM Scenarios

159. Figure 7 approximately locates three hypothetical scenarios on the plot from Section 8.1.3. An accurate location of these requires quantification of the materiality of the problem and the costs and benefits of the options, which is beyond the scope of this report, but is important piece of work on its own.

160. Scenario 1 is the present. There are occasional inertia shortage issues in Tasmania and South Australia, but the materiality is low, so the do (almost) nothing option (Section 8.2) is recommended. The definition of a RoCoF standard (Section 8.3.2) is also recommended for increased clarity of the operational task today, and in preparation for future scenarios.

161. Scenario 2 is around 2020. The materiality of the RoCoF management problem is moderate, affecting only SA and TAS, but about 30% of the time[42]. Moderate confidence in deliverability is needed as 2020 is close. Competitively-awarded contracts, or some combination of central planning and competitively-awarded contracts is recommended. An obligation-based contract design, as discussed in paragraph 144, would fit consistently with the self-commitment incentives faced by the existing synchronous generators, which are likely to be the major RoCoF management market participants in the near term. A market-clearing contract price, as discussed in paragraph 141, would give efficient incentives for plants to consider investing in reducing their minimum operating level.

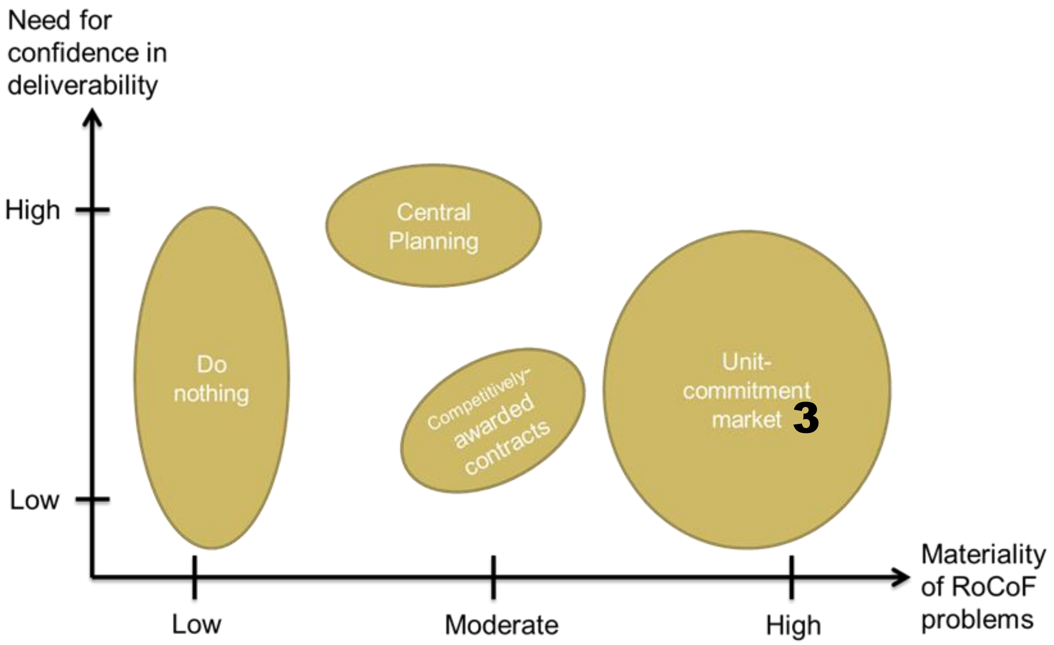

Figure 8 – Potential NEM Scenario 3 with Unit-commitment market R&D

162. Scenario 3 is for some point after 2020. The materiality is high, assuming that non-synchronous renewables continue to increase in penetration, and that the RoCoF problem will increase across the NEM. There is a lower need for confidence in deliverability as this is some time away, so developing and trialling a unit-commitment market is recommended as best promoting the National Electricity Objective. The technical and regulatory implementation of a unit-commitment market in the NEM and the practical outcomes it would give are currently not well understood. Early spending on R&D on

[42] From [5], see paragraph 21 for more detail.

this market design may alter the ranking of options to make a unit-commitment market a more certain choice[43] for Scenario 3, as shown in Figure 8.

9.2 Practical Implementation Issues in the NEM

163. Practical implementation of the recommended options in the NEM requires consideration of how to manage market power and how to best enable participation by the economically regulated networks. To best determine which of the diverse policy options to implement in the NEM, action is required by the COAG Energy Council.

9.2.1 Market Power

164. The competitively-awarded contract and unit-commitment market solutions rely on reasonable competition to deliver economically efficient outcomes. Tasmania, and to a lesser extent South Australia, are lacking sufficient participants for a competitive market[44]. The NEM as a whole does not have this problem. To reduce the impact of this market power, a centrally-planned or economically regulated solution may be required. Alternatively, a technology-neutral market solution may enable entry of other participants, increasing competition. More work is indicated on this difficult question of managing market power around RoCoF management.

9.2.2 Need for Regulatory Review of TNSP/DNSP Participation

165. TNSPs and DNSPs in the NEM are economically regulated large monopolies which operate under a revenue and/or price cap based on their asset base and efficient costs. This is appropriate for capital-intensive central-planning options, but in general provides poor incentives for NSPs to participate in RoCoF management service markets.

166. To install large capital assets such as synchronous condensers, a RIT-T proposal would be made to the AER, requiring a central-planning decision. In time, a market could provide good information to inform such decisions.

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[43] Alternatively, the R&D may show up problems with the approach, leading to more focus on other options, which is also a valuable outcome from early R&D.

[44] All of Tasmania's hydro is owned by the same company (Hydro-Electric Corporation) and the gas plants by another (AETV Pty Ltd), with one small wind farm[10]. SA has a number of owners across each of wind, gas and coal[9], but currently the participation in frequency ancillary services is low [5]. This may rise with increased incentives.

167. TNSPs and DNSPs in the NEM are seeing increasing use of battery technologies in place of network augmentation[17]. These batteries may offer a competitive stacked benefit in a RoCoF management service market.

168. It is recommended as further work to investigate what regulatory change is needed to facilitate the efficient participation of TNSPs and DNSPs in RoCoF management service markets.

9.2.3 Need for Co-ordination of Policy Making

169. A co-ordinated approach to policy making for the emerging RoCoF management problem is required, needing action from the COAG Energy Council[45]. The distributed decision-making responsibilities in the NEM are not well suited to determining the best policy trajectory for this complex problem.

170. Determining the policy trajectory for RoCoF management requires consideration of a diverse set of options. A framework is required to evaluate the options against the National Electricity Objective, such as the framework developed in this report. The options include network investment (regulated by the AER), rule changes and market creation (regulated by the AEMC) and frequency-standard review (by the Reliability Panel). Regulatory means to facilitate efficient participation in RoCoF management markets by NSPs may be needed, involving both the AEMC and AER. The technical power system security and integration issues, the responsibility of AEMO, are complex and interact with other emerging issues related to the changing generation mix, and will strongly inform the policy decisions.

171. The COAG Energy Council is best placed to act. It is able to commission a review by the AEMC of the emerging RoCoF management problems, to bring together all of the responsible bodies. Such a review would be able to consider not just today's emerging problem, but how to best address it as the power system continues to change.

[45] The Council of Australian Governments, the peak intergovernmental forum in Australia.

10 Areas for Further Investigation

172. This report conducted a high-level analysis of options to address emerging RoCoF management problems in the NEM. Further research is indicated on the following questions:

- What are suitable frameworks for measuring the materiality and urgency of the RoCoF management problem? (Sections 2.5 and 9.1)
- What is the best design of competitively-awarded contracts for RoCoF management services? (Section 8.5.1)
- How could a unit-commitment optimisation be practically implemented in the NEM? (Section 8.5.2)
- How can the impact of market power be minimised in the market options? (Section 9.2.1)
- What regulatory arrangements are needed to facilitate efficient participation by network service providers in RoCoF management service markets? (Section 9.2.2)
- What are accurate costings and implementation models for the central-planning options? (Section 8.4)
- What decision-making systems are needed to find the best policy trajectory, given the portfolio of rapidly changing options in a rapidly changing market? (Section 8.6)

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