AEMC

RULE CHANGE

Australian Energy Market Commission

CONSULTATION PAPER

National Electricity Amendment (Non-scheduled generation and load in central dispatch) Rule 2016

Rule Proponents

ENGIE and Snowy Hydro Limited

21 April 2016

Inquiries

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

E: aemc@aemc.gov.au
T: (02) 8296 7800
F: (02) 8296 7899

Reference: ERC0203

Citation

AEMC 2016, Non-scheduled generation and load in central dispatch, Consultation paper, 21 April 2016, Sydney.

About the AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

Contents

1 Introduction

On 24 December 2015 ENGIE (formerly known as GDF Suez Australian Energy) submitted a rule change request to the Australian Energy Market Commission (AEMC or Commission).[1] The rule change request seeks to amend the National Electricity Rules (NER or the Rules) to reduce the threshold at which non-intermittent generators are required to be scheduled from nameplate ratings greater than 30MW to nameplate ratings greater than 5MW.[2]

ENGIE has also proposed two additional changes to the Rules, which may operate in tandem or as alternatives to the proposed threshold reduction. These include creating a new 'soft scheduled' participant category and/or requiring changes to the Australian Energy Market Operator's (AEMO) pre-dispatch and dispatch processes to take into account price responsiveness of non-scheduled generators and non-scheduled loads.

This consultation paper has been prepared to facilitate public consultation and seek stakeholder submissions on the rule change request. This paper sets out:

- the background to the rule change request;
- a summary of the rule change request;
- an overview of the Commission's proposed assessment framework, and approach to assessing the rule change request;
- a number of questions and issues to facilitate consultation on this rule change request; and
- the process for making submissions.

The Commission has consolidated Snowy Hydro Limited's (Snowy Hydro) Demand side obligations rule change request with this rule change request because the issues in the rule change requests are closely related.[3] More information on the Demand side obligations rule change request and its consolidation with this rule change request is set out in Section 2.4.1 and the s. 93 notice published on the AEMC website with the consultation paper.

Submissions to this consultation paper are to be submitted by 19 May 2016. Details on how to lodge a submission are contained in Chapter 6 of this consultation paper.

1 Note: at the time the rule change request was submitted ENGIE was known as GDF Suez Australian Energy.

2 This paper refers to all non-intermittent generators as 'controllable' generators from this point on.

3 See: http://www.aemc.gov.au/Rule-Changes/Demand-side-obligations-to-bid-into-central-dispat.

2 Background

This chapter sets out an overview of:

- the relevant aspects of the design of the wholesale electricity market;
- the role of demand forecasting in the wholesale electricity market; and
- other relevant current and recent rule changes.

2.1 The wholesale electricity market

The National Electricity Market (NEM) operates in Queensland, New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory. Electricity is traded through AEMO's central dispatch process between generators (supply) and consumers (demand). AEMO is responsible for balancing the supply with demand in real-time through its dispatch process.

2.1.1 Generation in the NEM

A person who owns, controls or operates a generating system connected to a transmission or distribution network in the NEM is required to register as a generator with AEMO, except where they meet AEMO's criteria for an exemption.[4] Currently AEMO has a standing exemption for persons with generating systems with nameplate ratings less than 5MW.[5] AEMO also accepts applications for exemption from registration for persons with generating systems with nameplate ratings less than 30MW, but more than 5MW, if the generating system exports less than 20GWh in any 12-month period or there are extenuating circumstances.[6]

Registered generators must be classified as either market or non-market generators. A market generator is one that sells electricity it produces into the spot market at the spot price.[7] A non-market generator is one that sells all the electricity it produces directly to a local retailer or customer at the generator's connection point.[8]

Both market and non-market registered generators must be further classified as either scheduled, semi-scheduled, or non-scheduled generators. Generally, a generator:[9]

---

4 NER, clause 2.2.1(a).

5 In exceptional circumstances AEMO also accepts exemption applications for generating systems with nameplate ratings greater than 30MW.

6 See AEMO Guide to NEM Generator Classification and Exemption: http://aemo.com.au/About-the-Industry/Registration/How-to-Register/Exemption-and-Classification-Guides.

7 NER, clause 2.2.4.

8 NER, clause 2.2.5.

9 For the purposes of classification, where a group of generating units is connected at a common connection point, the generating units will be aggregated.

- with a nameplate rating of 30MW or more that has the technical capability to participate in the central dispatch process is classified as a scheduled generator;[10]
- with a nameplate rating of 30MW or more but which has intermittent output, such as a wind or solar farm, is classified as a semi-scheduled generator;[11] and
- with a nameplate rating less than 30MW or a generator that does not have the technical capability to participate in AEMO's central dispatch process is classified as a non-scheduled generator.[12]

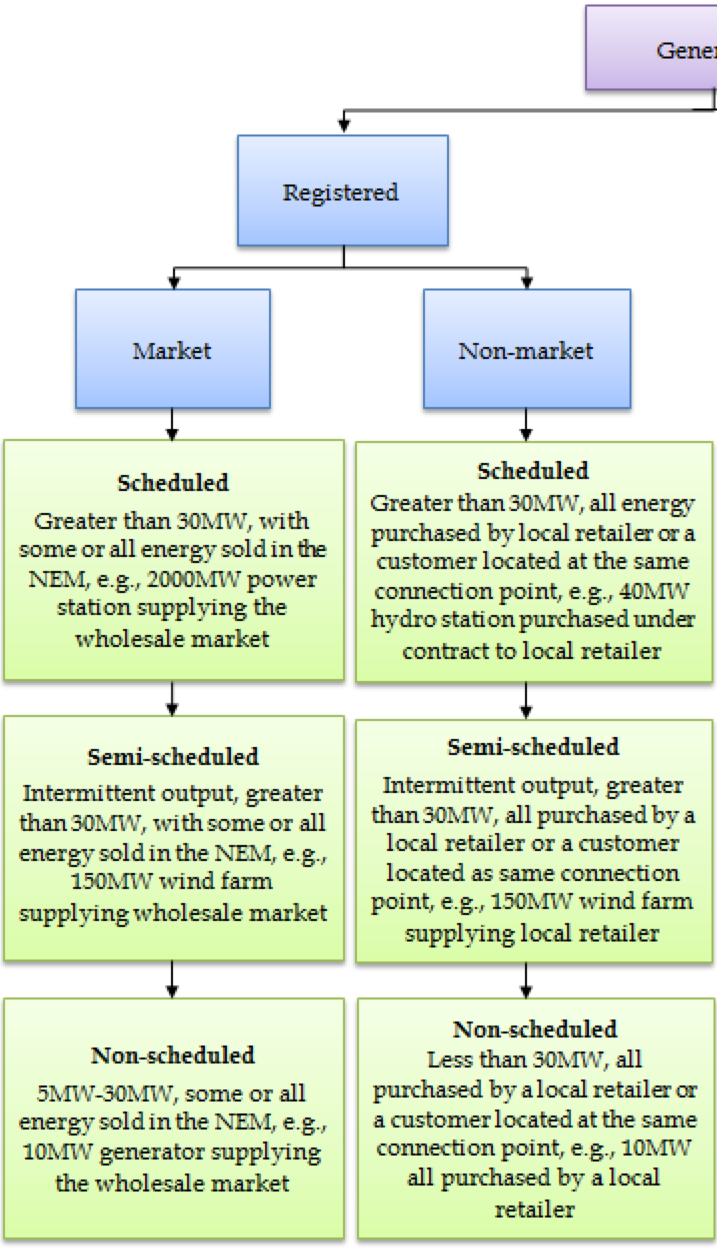
Examples of each type of generator classification are highlighted in figure 2.1.

10 NER, clause 2.2.2.

11 NER, clause 2.2.7(a).

12 NER, clause 2.2.3.

Figure 2.1 Generator classifications in the NEM



Under the Rules, AEMO may also exercise certain discretion in respect of elements of classification of generators. For example, in relation to a generator applying to be classified as non-scheduled, if in AEMO's opinion it is necessary for any reason (including power system security) it may require the generator to comply with some of the obligations of a scheduled or semi-scheduled generator.[13]

2.1.2 Load in the NEM

Most consumers in the NEM do not buy electricity directly from the spot market. They contract with a retailer and the retailer purchases electricity on their behalf in the spot

13 NER, clause 2.2.3(c).

market. The retailer may also hedge its exposure to the spot price through the purchase of derivative contracts. For many of these customers, the price they pay for electricity does not directly reflect the actual spot prices that the retailer paid for the electricity but rather reflects the retail tariff in the customer's retail contract. That said, it may be the case that the customer (usually a very large customer), as part of its retail contract, has contracted for some direct exposure to the spot price.

In addition to customers who contract with a retailer to purchase electricity, there are also a small number of customers who purchase electricity directly from the spot market. These customers are market customers and their loads are market loads. Market loads may either be scheduled or non-scheduled under the current provisions of the NER. The choice of being scheduled or non-scheduled lies with the market customer. If a load becomes a scheduled load, it will participate in AEMO's central dispatch process.[14]

2.1.3 Dispatch process

In the NEM, the settlement price is based on the average of the six five-minute dispatch interval prices over the 30-minute trading interval. Market participants that participate in AEMO's central dispatch process include scheduled and semi-scheduled generators, scheduled loads and scheduled network service providers. Participants are required to submit initial price/quantity bids for each of the 30 minute trading intervals to AEMO by 12:30 pm the day before the trading day.[15]

The bids specify the quantities at which each participant is willing to supply or consume electricity at nominated prices. For scheduled generators, bids specify the prices and the corresponding quantities that the generator is willing to supply. For scheduled loads, the bids specify the prices and the corresponding quantities that the load is willing to pay and consume.

Bids can contain up to ten price bands, with each band representing an incremental quantity of supply or demand. Although a scheduled participant has to put its initial bids in the day before the trading day, a scheduled participant does have the ability to submit a rebid. Rebidding can be undertaken at any time following the submission of the initial bid up until the relevant five-minute dispatch interval.

AEMO uses the information contained in all of the individual bids to create a bid stack representing the known supply and demand intentions of scheduled participants. AEMO also prepares a demand forecast which forecasts the demand and supply of all participants who are not scheduled. Once the bid stack has been created and demand forecasted, AEMO uses the information to dispatch generators or loads every five-minutes to balance the supply and demand of the electricity market in real-time.

---

14 To date, with the exception of a few pump storage facilities, no such customers have elected to become and remain a scheduled load.

15 Wholesale market participants are generators and scheduled loads. Generators make offers and loads make bids. Both make rebids when they vary their initial offer or bid. This paper will refer to both offers and bids as bids for simplicity.

The price at which the generator or load is dispatched (the dispatch price) is calculated by reference to the bid submitted by the marginal or last market participant dispatched to balance supply and demand. In the NEM, each of the five regions has its own regional spot price that is determined based on the supply and demand conditions in that region.

2.1.4 Pre-dispatch schedule

AEMO provides information to market participants prior to dispatch through its pre-dispatch schedule. Similar to the dispatch process, the pre-dispatch schedule combines the bidding information of scheduled participants with forecast demand to produce spot price, dispatch and ancillary service forecasts. AEMO does this for all trading intervals covering the period from the current trading interval up to and including the last trading interval for which participants have provided bids. AEMO updates and publishes the pre-dispatch schedule to provide market participants with up to date information.

The primary purposes of the pre-dispatch schedule are to:[16]

- provide wholesale market participants with sufficient information for them to make informed and timely business decisions relating to the operation of their scheduled generation and load; and

- provide AEMO with sufficient information to assist them in maintaining the power system in a reliable and secure operating state in accordance with the NER.

2.2 Demand forecasts

2.2.1 Types of demand forecast

In both the dispatch and pre-dispatch processes AEMO forecasts the amount of demand that is likely to occur in the market for each of the trading intervals. The demand forecast includes both non-scheduled load and non-scheduled generation. Non-scheduled generation acts as a reduction in the demand forecast because it reduces the supply that must be met by scheduled generation.

In pre-dispatch, the demand forecast is for each half-hourly trading interval, and is based on historical profiles of average actual demand and is adjusted by AEMO to suit forecast conditions. The major factors considered in AEMO's pre-dispatch demand forecast include temperature, weather season, week day/weekend, and unusual conditions, for example, public holidays.[17] In dispatch, the forecast demand at the end

16 AEMO, Pre-dispatch process description, July 2010, p.6.

17 For details about AEMO's pre-dispatch forecasting methodology, see Power System Operating Procedures – Load Forecasting, at: http://www.aemo.com.au/Electricity/Policies-and-Procedures/System-Operating-Procedures.

of each dispatch interval is based on the actual measured demand at the start of the dispatch interval plus a forecast demand change over the 5-minute interval.[18] Neither demand forecast explicitly takes into account price responsiveness of non-scheduled generators or loads.

2.2.2 Importance of demand forecasts

Accurate forecasting of electricity demand is an important feature of both the dispatch and pre-dispatch processes. For example:

- AEMO may use demand forecasts to inform its operational decisions and processes relating to:
  - the process by which the quantity and price of scheduled generation and scheduled load are dispatched;
  - the requirements for Frequency Control Ancillary Services (FCAS);[19]
  - procurement decisions, such as when to procure services through the Reliability and Emergency Reserve Trader (RERT) procedures.[20]
- other energy market stakeholders may use demand forecasts to inform aspects of their decision-making that relates to, for example, generation levels, consumption levels, network planning and regulatory purposes.

Market participants may also use the demand forecast information prepared by AEMO in making business or process decisions and therefore the accuracy of this demand forecast may play an important role in achieving efficient market outcomes.

2.3 Related rule change requests

2.3.1 Demand side obligations

The Commission received a rule change request from Snowy Hydro on 10 June 2015 seeking to amend the Rules to require that market loads 30MW or greater that are responsive to, or intend to be responsive to spot prices be registered as scheduled loads. The Commission released a consultation paper on 5 November 2015 in respect of

---

18 For details about AEMO's dispatch forecasting methodology, see Five Minute Electricity Demand Forecasting: Neural Network Model Documentation, at: http://www.aemo.com.au/Electricity/Policies-and-Procedures/Forecasting.

19 AEMO manages key technical characteristics of the power system, such as frequency and voltage, through ancillary services which it purchases from market participants.

20 Clause 3.20.2 of the NER provides that AEMO must take all reasonable actions to ensure reliability of supply and, where practicable, take all reasonable actions to maintain power system security by negotiating and entering into contracts to secure the availability of reserve under reserve contracts (known as RERT).

the rule change request and received submissions from stakeholders on 3 December 2015.[21]

The Commission has consolidated Snowy Hydro's rule change request with ENGIE's request because the issues raised in the requests are closely linked. In particular:

- both rule change requests seek to broaden the categories for mandatory participation in AEMO's central dispatch process;
- the benefits described in both requests relate to market efficiencies from more certain information being included in AEMO's dispatch and pre-dispatch processes; and
- the solutions proposed in both rule change requests and any possible alternatives the Commission may develop as a more preferable rule could apply to address the issues raised in both rule change requests.

The consolidated rule change request will be named Non-scheduled generation and load in central dispatch and the Commission will release a draft and final determination for the consolidated rule change as part of a single rule change process. Given the Commission has already released a consultation paper and received submissions on the Demand side obligations rule change request, this paper does not set out issues or seek further submissions on that request. Chapter 5 sets out issues that relate to the linkages between the two rule change requests and seeks submissions from stakeholders on these issues.

2.3.2 Other related rule changes

Current rule change requests

The Compliance with dispatch instructions (open) and the Five minute settlement (pending) rule change requests both relate to the operation of the wholesale market and obligations on scheduled generators and loads.[22] Any new rules that may arise out of these rule change requests may impact on the obligations on any new scheduled participants as a result of this rule change request. Furthermore, to the extent that any final rules arising from these requests may impact on the operation of the wholesale market they may affect the benefits and costs of this rule change request. Chapter 5 sets out questions in relation to these issues and the Commission welcomes submissions from stakeholders on any other interactions between these requests or other ongoing rule changes.

---

21 AEMC, Demand side obligations to bid into central dispatch, Consultation paper, 5 November 2015.

22 For information on the rule change requests see: http://www.aemc.gov.au/Rule-Changes/Five-Minute-Settlement and http://www.aemc.gov.au/Rule-Changes/Compliance-with-dispatch-instructions.

Recent rule change requests

The Commission published the Bidding in good faith final rule determination and final rule on 10 December 2015. The final rule amended the relevant provisions in the Rules as follows:[23]

- the requirement that bids be made in good faith was replaced by a prohibition against making false or misleading bids;
- any rebids need to be made as soon as practicable after the change in material circumstances and conditions giving rise to the rebid occurs; and
- a requirement to make a contemporaneous record of the circumstances surrounding late rebids was introduced.

In assessing this rule change request the Commission will have regard to:

- the costs that any new scheduled participants arising out of this rule change request may incur in complying with the Bidding in good faith final rule; and
- how changes to the operation of the wholesale market as a result of the Bidding in good faith final rule may affect the inefficiencies in the market put forward by ENGIE.

These issues are discussed in Chapter 5 and the Commission welcomes submissions from stakeholders on any other interactions between these requests.

23 AEMC, Bidding in good faith, Final rule determination, 10 December 2015, p. i.

3 Summary of the rule change request

This Chapter provides a summary of the rule change request, including an overview of ENGIE's:

- rationale for the rule change request;
- proposed changes to the Rules; and
- expected costs and benefits.

The full rule change request is available on the AEMC website and ENGIE's rule change request does not include a proposed rule.

3.1 Rationale for the rule change request

ENGIE considers that the ongoing success of the wholesale electricity market relies upon the ability of market participants to reasonably anticipate and respond to dynamic changes in the market. ENGIE considers that for this to be achieved all participants capable of impacting market outcomes need to be equally obliged to inform the market of their intentions.[24]

ENGIE considers that due to significant growth in the amount of non-scheduled generation in the market in recent years (and forecast further growth) non-scheduled generation is having a significant impact on market outcomes. Furthermore, because non-scheduled generators are not required to inform the market of their intentions, other generators' ability to respond to changes in their generation is limited. This in turn leads to inefficiencies in market outcomes since the most cost effective response can be impaired due to inadequate information.[25]

In addition to inefficient market outcomes, ENGIE considers that information asymmetries limit AEMO's ability to monitor and maintain the security of the power system, as key pieces of information are unavailable. ENGIE considers that where information is incomplete, AEMO needs to take a more conservative approach to managing the security of the power system and this contributes to inefficient asset utilisation and market outcomes.[26]

ENGIE therefore considers changes to the Rules are necessary to oblige non-scheduled generators to inform the market of their intentions.[27]

ENGIE submitted Figure 5.1 as evidence of the overall increase to date, and forecast continued increase in non-scheduled generation. ENGIE notes that while small wind

---

24 ENGIE, Rule change request, 24 December 2015, p.2.

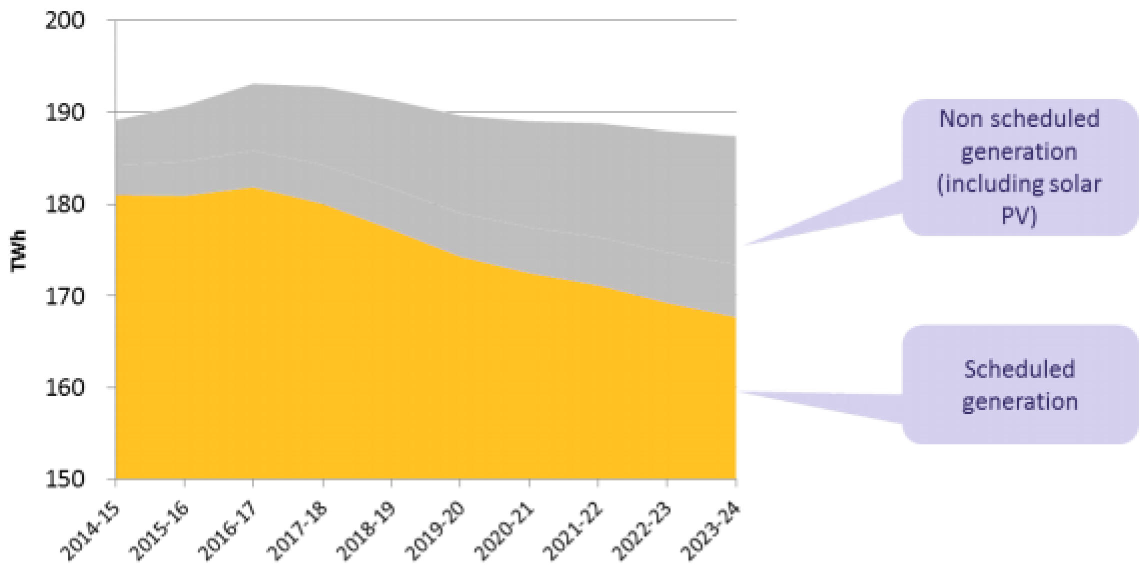
25 ENGIE, Rule change request, 24 December 2015, p.2.

26 ENGIE, Rule change request, 24 December 2015, p.2.

27 ENGIE, Rule change request, 24 December 2015, p.2.

farms and solar photovoltaic (PV) installations have contributed to this growth, the growth is not limited to such intermittent generation.[28]

Figure 3.1 Forecast generation from non-scheduled sources



Source: ENGIE, Rule change request, 24 December 2015, p.3. Sourced from the AEMO National Electricity Forecast Report 2014.

3.2 Proposed changes

ENGIE has proposed three options to address the issues identified in their rule change request, and considers that one or a combination of the three options could be implemented to address these issues. Each of the proposed options is summarised below and are discussed in Chapter 5.

3.2.1 Threshold reduction – Option one

ENGIE considers that the ideal solution to the issues identified is to reduce the threshold at which controllable generators are required to be scheduled from 30MW to 5MW.[29] By requiring generators above 5MW to be scheduled, and therefore bid into the market and follow dispatch instructions, ENGIE considers that the information asymmetries that currently exist regarding non-scheduled generators would be reduced.[30]

28 ENGIE, Rule change request, 24 December 2015, p.3.

29 ENGIE only proposes that wind generators would not be subject to the proposed threshold reduction. However, ENGIE has not proposed any changes to the threshold for intermittent generators to be semi-scheduled and due to technical constraints these generators are not capable of being scheduled. The Commission's explanation of ENGIE's rule change request therefore assumes the proposed rule change would not apply to other forms of intermittent generation.

30 ENGIE, Rule change request, 24 December 2015, p.5.

ENGIE proposes that the 5MW threshold apply to all new generator registration applications after the final rule is made.[31] Existing generators registered with AEMO as non-scheduled generators that are capable of being scheduled would be required to become scheduled generators by a nominated time.[32] ENGIE does not propose any changes to the requirements for intermittent generation.[33]

In addition to this option, ENGIE has proposed two other approaches for consideration. ENGIE does not prefer these options but considers they would improve the status quo if the Commission considers option one should not be applied to all controllable non-scheduled generators above 5MW.[34]

3.2.2 Soft scheduled – Option two

ENGIE's second option is to introduce a new participant category – a soft scheduled generator. Soft scheduled generators would be required to provide AEMO with information of their expected generation profiles but would not be required to meet the full bidding requirements or follow dispatch instructions.[35]

Under ENGIE's proposed model of soft scheduled generator, each would indicate to AEMO whether it is price responsive or non-price responsive, depending on whether its generation output changes in response to the NEM spot price. ENGIE proposes that:[36]

- price responsive soft scheduled generators would provide information on generation price-quantity response bands (up to ten bands) for the upcoming pre-dispatch period, and be allowed to update their band data up to one hour before actual dispatch; and
- non-price responsive soft scheduled generators would provide their expected generation profiles for each 30-minute interval in the upcoming pre-dispatch period, and may update this information up to one hour before actual dispatch.

ENGIE proposes that AEMO take into account price responsive soft scheduled generators' generation profiles in the same way as scheduled generators' profiles in the pre-dispatch and dispatch process.[37] Non-price responsive generators' generation profiles would be incorporated into the pre-dispatch and dispatch demand forecasts.[38]

---

31 ENGIE, Rule change request, 24 December 2015, p.5.

32 ENGIE does not set out what would define generators being capable of being scheduled and does not set out a timeframe for their registration.

33 ENGIE, Rule change request, 24 December 2015, p.11.

34 ENGIE, Rule change request, 24 December 2015, p.6.

35 ENGIE, Rule change request, 24 December 2015, p.6.

36 ENGIE, Rule change request, 24 December 2015, p.7.

37 Except that soft-scheduled generators would not be subject to network constraints.

38 ENGIE, Rule change request, 24 December 2015, p.7.

ENGIE does not propose that soft scheduled generators be required to follow dispatch instructions. However, ENGIE considers it is important to have a reasonable compliance obligation in place to require that soft scheduled generators take measures to run their generation in a manner which is consistent with the information provided to AEMO. ENGIE therefore proposes that soft scheduled generators be required to provide a report each month to the Australian Energy Regulator and AEMO comparing their forecast and actual generation. ENGIE also proposes that new rules be established to set tolerance limits on non-conformance with their generation profiles.[39]

3.2.3 AEMO proxy bids – Option 3

As a third option, ENGIE proposes that AEMO develops a new process to incorporate price responsiveness of non-scheduled generators into the demand forecast. This would involve AEMO, through existing real time measurements of demand at all connection points, correlated with five minute regional prices, preparing proxy price and quantity bids to represent the expected aggregate price response of non-scheduled generators.

ENGIE considers that a benefit of the proxy bid solution is that it could apply to all non-scheduled generators, including those less than 5MW, and also to all non-scheduled loads.[40]

3.2.4 Combined solutions

ENGIE proposes that all of the solutions could be combined. For example, ENGIE provides that one possible combination of the solutions could be to implement different options for different categories of participants in the following way:[41]

- Options 1 – plant required to be scheduled:
  - sized between 5MW and 30MW; and
  - connected after the final rule or connected before the final rule and capable of becoming scheduled.
- Option 2 – plant required to be soft scheduled:
  - sized between 5MW and 30MW;
  - connected before the final rule and not capable of becoming scheduled.
- Option 3 – captured by proxy bid process:
  - non-scheduled generators below 5MW.

39 ENGIE, Rule change request, 24 December 2015, p.8.

40 ENGIE, Rule change request, 24 December 2015, p.8.

41 ENGIE, Rule change request, 24 December 2015, p.5.

3.3 Expected costs and benefits

3.3.1 Costs

ENGIE's high level cost estimates of each of its proposed options on non-scheduled generators and AEMO are set out in Table 3.2. The costs of the proposed solutions and available alternatives are discussed in Chapter 5.

Table 3.2 ENGIE's estimated costs

	Option 1	Option 2		Option 3
For each non-scheduled generator:		Price responsive	Non-price responsive	
Establish communications platform	10,000 (one off)	5,000 (one off)	5,000 (one off)	N/A
Internal resource to establish policy and procedures	3,000 (one off)	1,500 (one off)	750 (one off)	N/A
Prepare and submit bids. Respond to dispatch instructions (option 1)	7,500 - 37,500 p.a.	7,500 p.a.	3,700 p.a.	N/A
Total cost for each non-scheduled generator	One off: 13,000 Ongoing: 7,500 - 37,500 p.a.	One off: 6,500 Ongoing: 7,500 p.a.	One off: 5,750 Ongoing: 3,700 p.a.	N/A
Cost to AEMO	Small increase	40,000 (one off)		One off: 160,000 Ongoing: 80,000 p.a.

Source: ENGIE, Rule change request, 24 December 2015, p.11.

3.3.2 Benefits

ENGIE notes that like many initiatives to improve market efficiency and effectiveness, the benefits that are expected to arise from the proposed change to the Rules are difficult to quantify accurately. ENGIE considers that the key benefits will include:[42]

- AEMO will be able to include the expected dispatch changes from price responsive non-scheduled generators in the NEM dispatch engine, thus reducing the likelihood of inefficient dispatch of scheduled generating units;
- the accuracy of the pre-dispatch forecasts will be improved by the inclusion of information regarding non-scheduled generator intentions. This will contribute to increased confidence in the accuracy of the pre-dispatch forecast by scheduled generators which will lead to:

42 ENGIE, Rule change request, 24 December 2015, p.13.

- improved dispatch efficiency: as scheduled generators will have more time to prepare to make changes in generation. For example, when a price spike is forecast 24 hours in advance and is believable some peaking gas generators might make arrangements for gas supply and transport, based on their pre-dispatch forecast schedule;
- improved investment certainty: generators will have increased confidence that difficult to predict price shocks, based on a lack of information transparency, will not arise. Such risks can cause participants to run at a loss which may harm long term financial viability and deter investment. Where investment is sub-optimal it can interfere with least cost delivery of energy to consumers. For instance, longer-term impacts on the efficient plant mix will increase the costs of energy to consumers; and
- improved contract pricing: improved information will promote accurately priced contracts, for example caps. Alternatively, contract prices may be inflated to manage the unexpected and difficult to predict impacts of non-scheduled generation. Better information reduces this source of inefficiency and risk. Inefficiently priced contracts will ultimately flow through to consumers. For example, inefficiently priced contracts harm retail markets and impact retail competition.

ENGIE considers that whilst difficult to quantify, the likely magnitude of these benefits is greater than the costs described above by a considerable margin.[43]

43 ENGIE, Rule change request, 24 December 2015, p.14.

4 Assessment Framework

4.1 NEO assessment

The Commission's assessment of the consolidated rule change request must consider whether the proposed rule will, or is likely to, contribute to the achievement of the National Electricity Objective (NEO).

The NEO is:[44]

> “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.”

Based on a preliminary assessment of the consolidated rule change request, the Commission considers that the most relevant aspects of the NEO for consideration are the efficient investment in and operation and use of electricity services for the long term interests of consumers with respect to the security and reliability of the national electricity system and the price of supply of electricity.

The Commission proposes to assess the contribution of the proposed rules to the promotion of the NEO through consideration of the following criteria:

- Prices that reflect the marginal cost of supply and value of its use: the potential of the proposed rule to better inform electricity spot prices by including more supply information, thereby increasing the accuracy of AEMO's dispatch process, pre-dispatch schedule and the price discovery process. This may lead to better investment and operational decisions by market participants, resulting in lower average prices for consumers in the long run.

- Improvements in market operation: the potential of the rule change request to decrease the amount of FCAS AEMO needs to procure to ensure the safe and reliable operation of the electricity system resulting from non-scheduled generators behaviour at various spot prices being known in advance. Where less FCAS is required to be procured, overall system costs and prices are likely to fall in the long run.

- Planning: the potential of the rule change to assist AEMO in planning and procuring other market services required to ensure the safe and reliable operation of the electricity system over the medium and long-term.

44 As set out under section 7 of the National Electricity Law (NEL).

- Prices of financial derivatives: is the proposed rule likely to reduce the prices of financial derivatives in the market through providing increased information to all parties in respect of the intentions of non-scheduled generators, decreased unexpected price volatility and reduced reliance on forecast inputs in the pricing of the derivatives.
- Potential regulatory and administrative burden: the potential regulatory and/or administrative burden on market participants, and in particular non-scheduled generators, that may arise if the proposed rule where to be implemented.
- Impact on market participants: the impact of the rule change on the incentives and obligations of market participants to participate in AEMO's central dispatch process.

4.2 Assessment approach

The Commission proposes to base the assessment framework on three steps as follows.

1. Defining and assessing the materiality of the problems:

   The Commission considers that in order to determine the effect of the proposed rules, the first step in the assessment framework is to define and assess the materiality of the problems that have been identified in the consolidated rule change request. This will involve an assessment of the costs that the issues create for market participants and how these costs flow through to impact consumers in the long-term.

   Determining the materiality of the problem may comprise both qualitative and quantitative assessments of the costs to market participants and may involve a degree of market modelling and analysis, depending on the nature of the problems identified.

   Electricity demand forecasting is by its nature an inexact process that will always produce inaccuracies. The Commission is therefore conscious that where the problem identified relates to inaccuracies in the dispatch and pre-dispatch demand forecasts, the benefits of such reductions will need to be considered in the context of the uncertainty that is inherent in forecasting electricity demand.

2. Given the materiality, identifying potential solutions to the problems

   In consideration of the extent and materiality of any problems that are identified, the next step in the assessment will be to determine potential solutions. The Commission's assessment will include consideration of all of ENGIE and Snowy Hydro’s proposed solutions, individually and together, as well as a range of alternative potential solutions.

   Depending on the issues identified the Commission may consider solutions that provide overall changes to the threshold for classification of all generators and loads, such as ENGIE's proposed threshold reduction, or more specific solutions, such as providing AEMO with discretion regarding generator and load classification. While the rule change requests propose regulation based approaches, the Commission may also consider whether there are alternative approaches based around market design that may provide incentives for generators to provide information to the market regarding their intentions.

3. Determining whether any potential solutions would result in net benefits to the market and promote the NEO

   Any potential solutions developed by the Commission will need promote the NEO. The Commission will assess the likely costs of the potential solutions and whether they are likely to outweigh the identified benefits.

   Within this assessment the Commission is conscious that any changes to the participants that are required to be scheduled may result in a trade-off between more scheduled participants providing more certain information to the market but higher costs of such participants meeting the requirements to be scheduled.

   The Commission may also examine who bears the costs of potential changes to the Rules and the incentives that potential changes provide to market participants. The Commission is cognisant of effects of making changes to the Rules that apply retrospectively, for example ENGIE's proposal to require existing registered non-scheduled generators to become scheduled. The Commission may therefore assess the impact of any potential changes to the Rules that affect market participants that have made business decisions based on the current Rules.

5 Issues for Consultation

This Chapter identifies a number of issues and questions for consultation relevant to ENGIE's rule change request. These are provided for guidance and stakeholders are encouraged to respond to these issues and questions as well as any other aspect of the rule change request.

The Chapter sets out issues and questions in relation to:

- the materiality of the issues identified by ENGIE;
- ENGIE's proposed, and potential alternative solutions; and
- ENGIE's estimated costs of its proposed solutions.

5.1 Materiality of the issues identified

ENGIE considers that there is an increased amount of price responsive non-scheduled generation in the NEM which is leading to a distortion in the NEM pre-dispatch and dispatch processes. ENGIE proposes this distortion arises through non-scheduled generators changing their output, either in response to the NEM wholesale price or some other locally determined process, without the change being fully taken into account by AEMO in either process.[45]

This section seeks stakeholders' views on the materiality of these issues in both the dispatch and pre-dispatch processes. ENGIE has also proposed that its proxy bid solution (option three) apply to price responsive non-scheduled loads and this issue is also considered.

5.1.1 Dispatch

Potential inefficiencies in the dispatch process

Sections 2.1.3 and 2.2 set out the operation of the dispatch process and how non-scheduled generation fits into the process. Most importantly, non-scheduled generation is included in the pre-dispatch and dispatch demand forecast. Changes in non-scheduled generation that are not forecasted therefore appear in the dispatch process as a variation of actual demand from forecast.

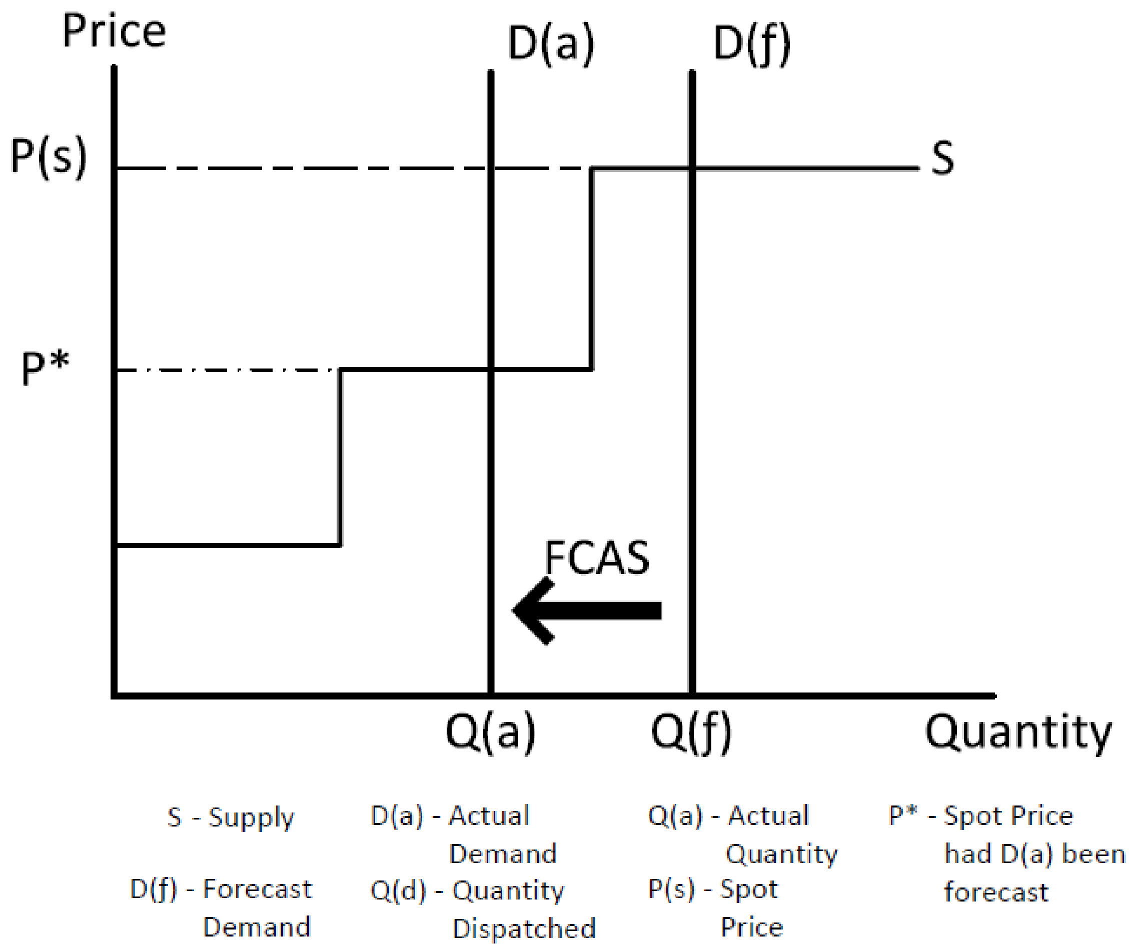
Figure 5.1 provides a stylised example of the outcomes in the dispatch process when a variation in actual demand from forecast occurs. In this simple example:

- AEMO forecasts demand to be D(f) and the bids of scheduled generators and scheduled loads create the bid stack resulting in a supply curve of S;

45 ENGIE, Rule change request, 24 December 2015, p.2.

- the spot price is set at P(s) and scheduled generators and loads are provided dispatch instructions to meet the resulting target demand Q(f);
- actual demand, represented by D(a), is lower than forecast demand D(f); and
- to balance supply and actual demand at Q(a), AEMO uses a portion of the lower FCAS it has procured.

Figure 5.1 Dispatch process: outcomes from demand forecast errors



The inefficiencies that may arise in the dispatch process as a result of a difference between the dispatch demand forecast and actual demand include:

- the spot price is set at a level which does not reflect the actual supply and demand conditions in the market. This may result in a number of inefficiencies, including:
  - the spot price provides signals to both generators and customers regarding their generation and consumption. For example, in Figure 5.1, the spot price P(s) may signal generators to increase supply or customers to decrease demand even though at P(s) there is currently more available supply than (actual) demand; and

- if the errors in the dispatch demand forecast occur systematically or at specific times or during specific events, there may be a bias towards higher or lower overall prices. This may result in inefficient signals for generation investment in the long run or significant wealth transfers between generators and customers or retailers. For example, if the most material errors occur from non-scheduled generators and loads responding to high spot prices then the average spot price may be higher than necessary to meet demand and this may be passed through to consumers in the long run.

- the cost of scheduled generation to meet actual demand may not be minimised. For example, in Figure 5.1, if the demand had been accurately forecast at D(a) then only the generators that bid in at prices P(*) or below would have been dispatched. With the demand forecast error, the adjustment of supply to reach Q(a) through regulation lower FCAS, which can only be made by generators capable of adjusting generation within the dispatch interval, may result in some higher cost generation being produced.

- the overall cost of supply and consumer prices may increase in the long term due to increased regulation FCAS payments. AEMO procures regulation FCAS on the basis of the likelihood of variation of supply being required to match demand. In doing so, AEMO takes into account the historical accuracy of supply and demand in the dispatch process. Therefore, if greater regulation FCAS is used, AEMO will likely increase procurement in the future. Similarly, as more of procured FCAS is used over time, providers of regulation FCAS may increase their regulation FCAS offer prices due to the higher likelihood of being called upon. This could increase the price of regulation FCAS in the future.

The Commission notes that the stylised example above presents a hypothetical example of the potential inefficiencies that may occur in the dispatch process from a demand forecast inaccuracy. This does not mean that unforeseen changes in non-scheduled generation will necessarily result in either demand forecast errors or inefficiencies in the dispatch process.

Sources of demand forecast error and materiality of resulting inefficiencies

Variances from the forecast dispatch demand and their resulting inefficiencies may arise from all components of the dispatch demand forecast, including:

- all non-scheduled load;[46]

- non-scheduled generation of unregistered generators, both intermittent and controllable; or

46 This includes almost all load in the NEM. To the Commission's knowledge, with the exception of a few pump-storage facilities there are currently no scheduled loads.

- non-scheduled generation of registered generators, both intermittent and controllable.

In assessing the rule change request the Commission will seek to identify both the source and materiality of relevant variances in the dispatch forecast (if any) and the inefficiencies they may cause. This will be particularly important in developing the appropriate (if any) solution. For example, if the market impacts of dispatch demand forecast errors from non-scheduled load greatly outweigh any dispatch demand forecast error from non-scheduled generation between 5MW and 30MW then the proposal to schedule generation between 5MW and 30MW may not result in material benefits.

Question 1 Potential inefficiencies in the dispatch process

1. **To what extent do non-scheduled controllable generators with nameplate ratings between 5MW and 30MW cause inaccuracies in the dispatch demand forecast and to what extent do such inaccuracies result in inefficiencies in the dispatch process through:**

   (a) **the spot price being set at a level which does not reflect the actual supply and demand conditions in the market?**

   (b) **the cost of scheduled generation meeting actual demand not being minimised?**

   (c) **increases to the cost of supply through higher FCAS costs in the long run?**

2. **If there are material inefficiencies, are these driven by any subset of non-scheduled controllable generators with nameplate ratings between 5MW and 30MW? For example, non-scheduled controllable generators with nameplate ratings between 20MW and 30MW, or non-scheduled controllable generators with nameplate ratings between 5MW and 30MW that are operated in tandem.**

3. **To what extent do price responsive non-scheduled generators below 5MW and price responsive non-scheduled customers cause inaccuracies in the dispatch demand forecast and to what extent do such inaccuracies result in inefficiencies in the dispatch process through:**

   (a) **the spot price being set at a level which does not reflect the actual supply and demand conditions in the market?**

   (b) **the cost of scheduled generation meeting actual demand not being minimised?**

   (c) **increases to the cost of supply through higher FCAS costs in the long run?**

ENGIE sets out the effects that errors in the dispatch demand forecast from unforeseen changes in non-scheduled generation have on particular types of generators during specific events and considers that these effects are very significant. For example, ENGIE submitted that:[47]

> "when the spot price in a region increases beyond their offer price, scheduled "fast-start" generators (typically gas turbines) in that region receive dispatch targets to come on line. Most fast-start generators require at least five minutes from the time of receiving a non-zero dispatch target, to the time to synchronise from rest. By this time, non-scheduled generators (who are not required to wait until they receive a dispatch instruction to come on line) can start to generate power, thus causing the measured demand to fall. In this situation, the fast start scheduled generator finds that by the time it has synchronised, the price has fallen below its bid price, and it then runs uneconomically for its minimum run time."

ENGIE considers this problem arises because non-scheduled generators are not required to advise AEMO of their dispatch intentions or price responsiveness and therefore AEMO is not able to take the impact of non-scheduled generation into account in the NEM dispatch and pre-dispatch processes. The dispatch targets sent to scheduled generators are therefore not as accurate as they could be, and can lead to inefficient dispatch and less effective power system control. ENGIE considers this can result in scheduled generators being dispatched uneconomically leading to them incurring large costs with no means of mitigation.[48]

The Australian Energy Regulator (AER) has also noted that in certain conditions the impact of even small unforeseen changes in demand may be much greater than usual. For example, the AER in its Special Report Market outcomes in South Australia during April and May 2013 provided:[49]

> "In a condition where a region is importing at or close to the interconnector limit, a change in demand can only be managed by ramping generators in that region. In South Australia around one quarter of conventional generation is fast start peaking plant that can start up in less than 30 minutes (but which cannot start in five minutes). When there are relatively few generators online, small changes in demand cannot be met by ramping generation in merit order, which can cause high priced offers to be dispatched setting very high five minute dispatch prices ..."

47 ENGIE, Rule change request, 24 December 2015, p.4.

48 ENGIE, Rule change request, 24 December 2015, p.4.

49 AER, Special Report Market outcomes in South Australia during April and May 2013, July 2013, p.30.

Question 2	Impacts on market participants from inefficiencies in the dispatch process

1. **Are specific market participants or types of market participants more significantly impacted by any inefficiencies in the dispatch process caused by inaccuracies in the dispatch demand forecast related to controllable non-scheduled generators between 5MW and 30MW?**

2. **Are the inefficiencies caused by inaccuracies in the dispatch demand forecast related to controllable non-scheduled generators between 5MW and 30MW more significant at specific times and/or under certain market conditions?**

3. **Are specific market participants or types of market participants more significantly impacted by any inefficiencies in the dispatch process caused by inaccuracies in the dispatch demand forecast related to controllable non-scheduled generators with nameplate ratings below 5W or non-scheduled loads that are price responsive?**

4. **Are the inefficiencies caused by inaccuracies in the dispatch demand forecast related to price responsive controllable non-scheduled generators below 5MW and non-scheduled loads more significant at specific times and/or under certain market conditions?**

5.1.2 Pre-dispatch

One key function of pre-dispatch is to provide market participants with information about power system security and reliability issues, and to encourage a market response to resolving those issues ahead of any market intervention by AEMO.

ENGIE considers that asymmetries in the obligations of different market generator classification types to provide inputs to AEMO may limit the ability of AEMO to monitor and maintain the security of the power system, as key pieces of information are unavailable. ENGIE argues that where information is incomplete, AEMO needs to take a more conservative approach to managing the security of the power system. This in turn contributes to inefficient asset utilisation and market outcomes.[50]

Another key function of pre-dispatch is to provide market participants with spot market information, to allow them to make informed decisions about the operation of their plant and management of financial risks. ENGIE considers that the accuracy of pre-dispatch forecast is particularly important to the generators that need to finalise operational arrangements for the upcoming day. For example, some peaking gas

50 ENGIE, Rule change request, 24 December 2015, p.2.

generators might make arrangements for gas supply and transport, based on the forecasts in the pre-dispatch schedule.[51]

The degree of reliance on pre-dispatch information may vary among market participants. For example, some generators may use AEMO's pre-dispatch information as one of a number of inputs in forming their own forecasts. These generators may form views about changes in non-scheduled load, non-scheduled generation, and bids and may form a view about supply and demand conditions different from the pre-dispatch schedule.

The time needed to respond may also vary among market participants. For example, some fast responding generators are able to adjust their operations quickly in response to changes in market conditions. Other generators may need more time to ramp up or ramp down and hence may need to make decisions regarding generating over multiple dispatch periods. Generators may also use the inflexibility profile procedures provided by AEMO to assist with the impacts of ramping up and down. Therefore, inaccuracies in the pre-dispatch schedule may impact market participants differently.

AEMO has noted that a number of factors can contribute to differences between pre-dispatch and dispatch outcomes.[52] The factors relate to the market design, its implementation, or externalities such as unforeseen power system events. For example, as highlighted in Section 2.2.1, one implementation factor is that AEMO uses different pre-dispatch and dispatch demand forecast methodologies which may cause differences in the demand forecasts.

ENGIE considers that if AEMO is able to include in the pre-dispatch forecasts information regarding the intentions of non-scheduled generators, it will contribute to a more accurate forecast of how scheduled generators will be dispatched, and lead to more efficient dispatch.[53]

In its recently finalised Bidding in good faith final rule determination, the Commission noted the importance of market confidence in the reliability of pre-dispatch information. ENGIE considers that the inefficiencies relevant to this rule change request are akin to those cited by the Commission in seeking to better manage late rebidding. That is, where information that could be made available to the market is not made available, in this case non-scheduled generators' intentions, it will lead to avoidable inefficiencies.[54]

51 ENGIE, Rule change request, 24 December 2015, p.14.

52 For details, see: Factors Contributing to Differences between Dispatch and Pre-dispatch Outcomes, at http://www.aemo.com.au/Electricity/Market-Operations/Dispatch/Factors-Contributing-to-Differences-between-Dispatch-and-Predispatch-Outcomes.

53 ENGIE, Rule change request, 24 December 2015, p.13.

54 ENGIE, Rule change request, 24 December 2015, p.10.

Question 3 Potential inefficiencies in pre-dispatch

1. **To what extent do controllable non-scheduled generators with nameplate ratings between 5MW and 30MW cause inaccuracies in the pre-dispatch demand forecast and to what extent do such inaccuracies result in inefficiencies in the price discovery process?**
2. **To what extent do price responsive controllable non-scheduled generators below 5MW and price responsive non-scheduled loads cause inaccuracies in the pre-dispatch demand forecast and to what extent do such inaccuracies result in inefficiencies in the price discovery process?**
3. **Are specific market participants or types of market participants more significantly impacted by inefficiencies caused by inaccuracies in the pre-dispatch demand forecast?**

5.2 Proposed and alternative solutions

ENGIE's three specific solutions all relate to increasing the amount of information that enters the pre-dispatch and dispatch processes. In assessing each of the proposed solutions and any potential alternatives a key issue will be identifying the cause and materiality of any inefficiencies in the current processes. This will then drive the most appropriate solution (if any).

5.2.1 ENGIE's proposed solutions

Option 1

ENGIE's preferred solution is to change the threshold at which controllable generators must be scheduled from 30MW to 5MW. ENGIE proposes that the reduced threshold apply to new generators registering with AEMO and that all existing non-scheduled registered generators that are reasonably capable of being scheduled should be required to be scheduled after a nominated period. ENGIE considers that this approach is the most effective in overcoming the lack of transparency in the NEM and will enable AEMO to manage the dispatch and pre-dispatch process in a more complete and accurate manner.[55]

ENGIE's rule change request does not set out a justification for 5MW being the new threshold other than that it considers as many generators as possible should be required to be scheduled and 5MW is the current threshold for generators to be registered.[56]

55 ENGIE, Rule change request, 24 December 2015, p.5.

56 ENGIE, Rule change request, 24 December 2015, p.5.

If option one was implemented, the effect would be to remove some current non-scheduled generation between 5MW and 30MW from the pre-dispatch and dispatch demand forecasts and add them to the bid stack in the pre-dispatch schedule and dispatch process. Operationally this would appear in the processes as an increase in both supply, through the additional generators bids being added to the bid stack, and an increase forecast demand, as the non-scheduled generation (which acts as a demand reduction) is removed. The effect on spot prices from such a change is uncertain and would depend on both the bids that the new scheduled generators make relative to the quantities that would have been forecasted and responses to the additional information by other market participants.

While the effect on the spot price is uncertain, through the generators being required to provide bidding information to AEMO and the requirement to follow dispatch instructions, more certain information is likely to be included in the pre-dispatch and dispatch processes. The scheduling would also mean that the price responsiveness of such generators would be taken into account directly in the pre-dispatch and dispatch processes.

In assessing option one, if a material issue is identified the Commission may also assess a variety of related alternatives. These could include:

- an overall review of the appropriate threshold for controllable generators to be scheduled. The Commission may then assess the current 30MW threshold, ENGIE's proposed 5MW threshold and alternative thresholds; and
- a more flexible threshold. For example, instead of being based on nameplate rating, the characteristics or impacts of a generator or a group of generators could be taken into account by AEMO. This could involve an extension of AEMO's existing discretion to require non-scheduled generators to meet requirements of scheduled generators or an ability of AEMO to require non-scheduled generators to be scheduled based on their specific characteristics.

In assessing the appropriate threshold for generators to be scheduled, the Commission may also need to consider the current threshold for registration of generators.[57]

Question 4 Option one

As noted in Section 4.2, the Commission considers the appropriate solution will depend on the materiality and sources of the issues analysed in Section 5.1. The questions below seek stakeholders' views in the context of addressing both the materiality and source of the inefficiencies.

1. Is there a case for reviewing the threshold for generators to be scheduled? If so:

(a) Would a decrease in the threshold to be classified as a scheduled

57 This is currently determined by AEMO through its NEM generator classification and exemption guideline.

generator from 30MW to 5MW reduce inefficiencies in the dispatch and pre-dispatch/price discovery process? Is there a more preferable nameplate rating threshold?

(b) Would a more flexible threshold for the requirement to be scheduled reduce inefficiencies in the dispatch and pre-dispatch/price discovery process? If so, what should be taken into account in a more flexible threshold?

Option 2

ENGIE's second option is to introduce a new participant category – soft scheduled generator. ENGIE proposes that this option only apply if the Commission decides not to apply option one to some or all controllable non-scheduled generators between 5MW and 30MW or existing generators within this group that are not reasonably able to become scheduled.[58]

ENGIE proposes that soft scheduled generators would not be required to meet the full bidding requirements or follow dispatch instructions.[59] Instead, price responsive soft-scheduled generators would be required to submit information in the form of generation price-quantity response bands for each trading period. Similarly, non-price responsive soft-scheduled generators would be required to submit information regarding their expected generation quantity (profile) for each trading period.

While ENGIE does not propose soft scheduled generators be required to follow dispatch instructions, ENGIE considers it is important to have a reasonable compliance obligation in place to require them to take measures to run their generation in a manner which is consistent with the information provided to AEMO. ENGIE therefore proposes that soft scheduled generators be required to provide a report each month to the Australian Energy Regulator and AEMO comparing their forecast and actual generation. ENGIE also proposes that new rules be established to set tolerance limits on non-conformance with their generation profiles.[60]

ENGIE proposes that AEMO take into account price responsive soft scheduled generators' price-quantity response bands in the same way as scheduled generators' bids are considered in the bid stack in the pre-dispatch and dispatch process.[61] The generation profiles of non-price responsive soft scheduled generators would be used by AEMO in preparing the demand forecast for the relevant region.[62]

ENGIE proposes that both price responsive and non-price responsive soft scheduled generators could update the information provided up to one hour before actual

58 ENGIE, Rule change request, 24 December 2015, p.6.

59 ENGIE, Rule change request, 24 December 2015, p.6.

60 ENGIE, Rule change request, 24 December 2015, p.8.

61 Except that soft-scheduled generators would not be subject to network constraints.

62 ENGIE, Rule change request, 24 December 2015, p.6.

dispatch. This 'gate close' requirement is stricter than current requirements for scheduled generators which are, subject to some restrictions, able to change their bid quantities up to the commencement of the dispatch interval. ENGIE suggests that such time lag may be necessary for AEMO to incorporate the information into the pre-dispatch and dispatch forecasts.[63]

Unlike scheduled generators which are required to submit bids in advance for each five minute dispatch interval, ENGIE suggests that soft scheduled generators would be required to provide information for each thirty minute trading interval. Furthermore, while scheduled generators are required to submit their bids in advance for the upcoming trading day, no such requirement is proposed by ENGIE for soft-scheduled generations. However, in practice, it may be practical for soft-scheduled generators to define their price and/or quantity for several trading intervals or even days in advance.

For price responsive soft scheduled generators ENGIE propose to use the dispatch inflexibility profile and the minimum loading level as a 'template' for AEMO's consideration. The rule change request suggest that AEMO should take these into consideration in the same way as for scheduled generators, with the exception that the soft scheduled generators would not be subject to network constraints.

There are several further market design questions that would need to be explored in order assess such option. Among others, the question whether the price-quantity bids submitted by price responsive soft scheduled generators may set the price for a given dispatch period is crucial.

Currently non-scheduled generators do not directly influence the dispatch forecast of AEMO. This is because AEMO only considers non-scheduled generators indirectly through the changes in their generation levels in the previous five dispatch periods (previous 25 minutes) immediately prior to the actual dispatch period. If option two were implemented, non-price responsive soft-scheduled generators may directly impact dispatch outcomes as AEMO would be required to consider them by altering the demand-forecast.

Question 5 Option two

1. **Should price-quantity response bands submitted by price responsive soft scheduled participants be able to set the dispatch price? If so, is this consistent with the requirement that soft scheduled generators' price-quantity bids are not subject to network constraints or follow dispatch instructions?**

2. **If soft scheduled generators do not receive, and are not required to follow dispatch instructions, what (if any) enforcement mechanism should be in place to require them to provide accurate information regarding their generation intentions? To what degree will the benefits**

63 ENGIE, Rule change request, 24 December 2015, p.6.

of extra information in the pre-dispatch schedule and dispatch process regarding these generators intentions be reduced if they are not issued with, and required to follow dispatch instructions?

3. Is there a risk that information submitted by price-responsive and non-price responsive soft scheduled generators may be used strategically to influence the bid stack (price-responsive) or the demand forecast (non-price responsive generators) and hence market outcomes?

4. If this solution is applied to price responsive loads over 30MW to what extent (if any) is it likely to reduce the benefits of the proposed rule in the Demand side obligations rule change request?

Option 3

As a third option that may be implemented in tandem with other options or as a standalone option, ENGIE proposes that AEMO develops an analytical process to incorporate price responsiveness of non-scheduled generators and to include these in the pre-dispatch forecast and dispatch processes. This would be done through proxy bids (price-quantity offer bands) developed by AEMO. AEMO would calculate these based on existing real time measurements of demand at all connection points and correlate them with the dispatch prices.

ENGIE notes that AEMO already uses and is in the process of developing similar analytical approaches for wind and solar generators, respectively.

Timely access to metering information at the level of all relevant connection points may be one of the critical inputs required for the proposed solution.

While AEMO is likely to have access to information as it is required for settlement purposes, whether the granularity, accuracy and timeliness of such data is suitable for the purpose described in the rule change request requires investigation. Alternatively, the installation of special metering equipment may be required with telemetry capabilities so AEMO receives data important for its analysis without delays.

ENGIE notes that there may be arguments against AEMO preparing and submitting proxy offers on the basis that the independent market operator should not be a player in the market. ENGIE is sympathetic towards this view and states that appropriate safeguards would need to be in place to ensure that AEMO's involvement was appropriate.

ENGIE notes that an advantage of option three is that it may be able to be applied to price responsive non-scheduled generators less than 5MW and non-scheduled loads.

Question 6 Option three

1. To what extent is this solution likely to increase efficiency in the dispatch process through including proxy bids to capture the price

responsiveness of non-scheduled generators and non-scheduled loads?**

2. **Should proxy bids by AEMO be able to set the prices in a dispatch period? If so, is this option consistent with AEMO's role as an independent market operator?**

3. **What safeguards would need to be in place to ensure that AEMO's role as an independent market operator is not compromised?**

4. **What would be the benefits of applying this solution more broadly than ENGIE has proposed? For example, could this solution be applied to the large price responsive loads proposed to be scheduled in the Demand side obligations rule change request?**

5. **What are the data and technical requirements for implementation of this option?**

5.2.2 Alternative solutions

Currently, the obligation of providing pre-dispatch and dispatch information rests with AEMO. The Rules and procedures are designed for AEMO to gather and provide information that may be valuable to market participants. Market participants rely on this information to different degrees based on their own expectations and ability to gather alternative information. For example, some market participants may adjust AEMO's forecasts to incorporate information that they gather that is absent from AEMO's pre-dispatch schedule and dispatch process.

Transmission network service providers (TNSPs) and distribution network service providers (DNSPs) may have access to more complete information and in a more timely manner than AEMO. Furthermore, TNSPs and DNSPs may already use analytical models to predict changes in, for example, load shapes and or non-scheduled generation output in their respective service areas as such analysis may have implications for the reliable and secure operation of their respective networks. Therefore, it may be worth considering how TNSPs and DNSPs may be incentivised to contribute to the accuracy of pre-dispatch and dispatch forecast.

Question 7 Alternative solutions

1. **Could information provision and information aggregation be achieved through market-based incentives rather than regulatory measures? If so, in what form?**

2. **Are there any examples in other markets (in Australia or overseas) where information provision and information aggregation solutions are utilised through non-regulatory means?**

5.3 Costs and regulatory burden

After assessing the materiality of the issues identified and the proposed and available solutions, the Commission will weigh the likely benefits of each solution against the cost of each. ENGIE has set out high level estimates of the costs of each of its proposed solutions for non-scheduled generators and AEMO in its rule change request. These are summarised in Table 5.1 below.

The Commission may also analyse how likely changes to participants costs from the proposed and alternative solutions are likely to affect captured generators' incentives to participate in the market. For example, ENGIE notes that requiring all generators registering with AEMO to be scheduled is likely to result in some businesses whose primary focus is not operating in the wholesale electricity market to be scheduled.[64] If changes to the Rules add additional costs to such generators they may choose not to enter the market, which could result in a higher overall cost of supply in the long run.

64 ENGIE, Rule change request, 24 December 2015, p.5.

Table 5.1 ENGIE's estimated costs

<table>
<tr><th></th><th>Option 1</th><th colspan="2">Option 2</th><th>Option 3</th></tr>
<tr><td>For each non-scheduled generator:</td><td></td><td>Price responsive</td><td>Non-price responsive</td><td></td></tr>
<tr><td>Establish communications platform</td><td>10,000 (one off)</td><td>5,000 (one off)</td><td>5,000 (one off)</td><td>N/A</td></tr>
<tr><td>Internal resource to establish policy and procedures</td><td>3,000 (one off)</td><td>1,500 (one off)</td><td>750 (one off)</td><td>N/A</td></tr>
<tr><td>Prepare and submit bids. Respond to dispatch instructions (option 1)</td><td>7,500 - 37,500 p.a.</td><td>7,500 p.a.</td><td>3,700 p.a.</td><td>N/A</td></tr>
<tr><td>Total cost for each non-scheduled generator</td><td>One off: 13,000
Ongoing: 7,500 - 37,500 p.a.</td><td>One off: 6,500
Ongoing: 7,500 p.a.</td><td>One off: 5,750
Ongoing: 3,700 p.a.</td><td>N/A</td></tr>
<tr><td>Cost to AEMO</td><td>Small increase</td><td colspan="2">40,000 (one off)</td><td>One off: 160,000
Ongoing: 80,000 p.a.</td></tr>
</table>

Question 8 Costs

1. **Are ENGIE's estimates of the costs of each proposed solution on AEMO and controllable non-scheduled generators accurate? If not, what are the likely costs of each solution?**

2. **Are the costs likely to vary for some non-scheduled generators from others? For example, would the costs of becoming scheduled vary for:**

   (a) **Existing non-scheduled generators required to become scheduled?**

   (b) **Non-scheduled generators whose primary focus is not generating electricity?**

   (c) **Types of generation?**

3. **Is a reduction in the threshold for controllable generators likely to affect the incentives for captured generators to enter or interact with the market? If so, what is the likely effect of such a change?**

6 Lodging a Submission

The Commission invites written submission on this rule change request.[65] Submissions are to be lodged online or by mail by 19 May 2016 in accordance with the following requirements.

Where practicable, submissions should be prepared in accordance with the Commission's Guidelines for making written submissions on Rule change requests.[66] The Commission publishes all submissions on its website subject to a claim of confidentiality.

All enquiries on this project should be addressed to Yuelan Chen on (02) 8296 0606.

6.1 Lodging a submission electronically

Electronic submissions must be lodged online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the project reference code "ERC0203". The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

Upon receipt of the electronic submission, the Commission will issue a confirmation email. If this confirmation email is not received within 3 business days, it is the submitter’s responsibility to ensure the submission has been delivered successfully.

6.2 Lodging a submission by mail or fax

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated. The submission should be sent by mail to:

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

The envelope must be clearly marked with the project reference code: ERC0203.

Alternatively, the submission may be sent by fax to (02) 8296 7899.

Except in circumstances where the submission has been received electronically, upon receipt of the hard copy submission the Commission will issue a confirmation letter.

If this confirmation letter is not received within 3 business days, it is the submitter’s responsibility to ensure successful delivery of the submission has occurred.

---

65 The Commission published a notice under section 95 of the NEL to commence and assess this rule change request.

66 This guideline is available on the Commission's website.

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Commission	See AEMC
DNSP	distribution network service provider
FCAS	Frequency Control Ancillary Services
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER or the Rules	National Electricity Rules
PV	solar photovoltaic
RERT	Reliability and Emergency Reserve Trader
TNSP	transmission network service provider