Non-scheduled generation and load in central dispatch

Considering the issues raised and potential solutions

Presentation slides and Summary of Discussion

Industry workshop
Stamford Hotel, Melbourne
24 March 2017

List of organisations represented

AGL Energy	EnerNOC	Major Energy Users
Australian Energy Council	ENGIE	Norton Rose Fulbright
Australian Energy Market Operator	Ergon Energy	Private individuals
Australian Renewable Energy Agency	ERM Power	Snowy Hydro
Delta Electricity	GHD	Stanwell
Department of the Environment and Energy	Global-Roam	Sun Metals
Energy Market Consulting Associates	Greenview Strategic Consulting	United Energy and Multinet Gas
Energy Australia	Intelligent Energy Systems	Woolnorth Wind Farm Holdings

Agenda

Time	Item
10.30 – 10.45am	Welcome and overview of workshop
10.45 – 11.00am	The rule change requests
11.00 – 12.15pm	Evidence and materiality of issues raised
12.15 – 1.00pm	Lunch break
1.00 – 2.45pm	Assessment of proponents' and other options
2.45 – 3.00pm	Wrap-up and close

THE RULE CHANGE REQUESTS

The rule change requests

The rule change requests seek to amend the rules that govern the obligations of non-scheduled generating units and loads to participate in the central dispatch process.

On 10 June 2015, Snowy submitted that market loads greater than 30MW, which are or intend to be price responsive, become scheduled loads and be required to submit bids and follow dispatch instructions.

On 24 December 2015, ENGIE submitted three options:

- non-intermittent non-scheduled generating units between 5-30MW be scheduled;
- create a "soft scheduled" participant category with information obligations;
- AEMO to submit "proxy bids".

The options may be assessed individually or in combination.

On 18 April 2016, the two rule change requests were consolidated.

Snowy: statement of issues

Snowy considers that transparency of supply and demand is essential for efficient price discovery.

The lack of transparency:

- reduces the accuracy of the pre-dispatch and dispatch prices;
    - inefficient generation costs
- reduces AEMO's ability to forecast adequate reserves and manage the central dispatch process through accurate representations of constraint equations;
    - system security and FCAS cost implications
- impedes efficient pricing of financial contracts.

As a matter of equity, operators of loads must have corresponding obligations to inform the market of their intentions.

ENGIE: statement of issues

ENGIE considers that all participants capable of impacting market outcomes should be equally obliged to inform the market of their intentions.

Asymmetric obligations to provide market inputs undermines the ability of all participants to respond equally to market changes.

Asymmetry and a lack of transparency:

- leads to inefficient pre-dispatch and dispatch outcomes;
- impacts AEMO's ability to monitor and maintain the security of the power system; and,
- results in inefficient asset utilisation;

How would changes promote the NEO?

*The **National Electricity Objective** 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.

Improved efficiency of spot market operations

Improved ability for AEMO to manage the power system

More accurate pre-dispatch and dispatch forecasts

More accurate forecasting of reserve requirements

More efficient asset utilisation

More efficient pricing of financial contracts

EVIDENCE FOR, AND MATERIALITY OF, THE ISSUES

Evidence and materiality of issues raised

Capacity for market distortion
• Non-scheduled load
• Non-scheduled generation

Evidence of market distortion
• AER data
• Quantitative analysis
• FCAS costs
• Other costs

Non-scheduled participants may impact demand forecasting accuracy by changing their generation or consumption profile.

Are market distortions quantifiable and attributable?

Other evidence?

Capacity for distortion:
Non-scheduled loads in the NEM

Load in the NEM, October 2015

		No.	Aggregate load (MW)	% of total NEM load
Scheduled		4	720	2.8%
Non-scheduled	> 30MW	36	4,726	18.4%
	Other	N/a	20,204	78.8%
Total			25,650	100.0%

Most market participants have chosen not to be scheduled

Capacity for distortion:
Non-scheduled loads in the NEM

Summary of market loads > 30 MW by region

	Average regional demand	No. of loads	Aggregate load size (MW)	Aggregate load size (%)
NSW	9600	12	1451	15.1%
VIC	6650	5	859	12.9%
SA	1700	3	200	11.8%
QLD	6500	12	1724	26.5%
TAS	1200	4	492	41.0%

The proportion of demand from large loads varies by region

Capacity for distortion:
Non-scheduled generation in the NEM

Market generation in the NEM (MW), November 2016

	Non-intermittent			Intermittent		
	Scheduled	Semi-scheduled	Non-scheduled	Scheduled	Semi-scheduled	Non-scheduled
Above 30MW	43,222	-	798	-	2,793	1,064
15MW - 30MW	79	-	452	-	-	159
10MW - 15MW	-	-	160	-	-	24
5MW - 10MW	-	-	154	-	-	16
Below 5MW	-	-	160	-	-	10
Total	43,301	-	1,724	-	2,793	1,273

There is ~2.8GW of non-scheduled generation > 5MW in the NEM.
This is ~ 6% of total nameplate generation capacity.

Capacity for distortion:
Non-scheduled generation by region

Non-scheduled nameplate generation capacity by region (>5 MW)

		Non-intermittent	Intermittent	Total non-scheduled	Total generation	N-S as % of total
NSW	> 30MW	311	141	722	16208	4.5%
	> 5 MW <= 30 MW	210	60			
Qld	> 30MW	455	0	781	12917	6.0%
	> 5 MW <= 30 MW	314	12			
SA	> 30MW	0	389	399	4589	8.7%
	> 5 MW <= 30 MW	10	0			
Tas	> 30MW	0	140	246	2970	8.3%
	> 5 MW <= 30 MW	106	0			
Vic	> 30MW	32	394	679	12237	5.5%
	> 5 MW <= 30 MW	126	127			
NEM total	> 30MW	798	1064	2827	48921	5.8%
	> 5 MW <= 30 MW	766	199			

The amount of non-scheduled generation varies by region.

* Removing Hazelwood from the Victorian calculation changes the non-scheduled proportion to 6.4%

Capacity for distortion:
Non-scheduled generation units

Number of generation units: non-scheduled generation in the NEM > 5MW			
	Non-intermittent	Intermittent	Total
Above 30 MW	14	11	25
15 MW - 30 MW	19	7	26
10 MW - 15 MW	12	2	14
5 MW - 10MW	20	2	22
Total	65	22	87

There are 87 non-scheduled generation units >5MW in the NEM, out of 287 registered generation units.

Summary of comments on issues analysis

- Comments on the capacity for market distortion (slides 11 – 15)
  - Capacity data shown excludes solar PV behind the meter
  - Percentage of energy and volume can be much higher than the % capacities shown
  - Percentage of non-scheduled generation was a lot less 10 years ago, and will be a lot higher in 5-10 years which may have an impact on the materiality of the issue
  - Need to look at price responsive behaviour in addition to market capacities

Evidence of distortion:
AER data

AER significant price variation data			
	2014	2015	2016
No. of instances	71	133	273

AER data indicates increasing variation between the pre-dispatch forecast and the actual spot price.

AER price variation data

	2014	2015	2016
Availability	50%	48%	41%
Combination	10%	7%	13%
Demand	40%	45%	46%
Network	0%	0%	0%

Some increase in *Demand* as the cause of variation is evident.

This could be caused by participant actions or forecast error.

Evidence of distortion:
Quantitative analysis

EY was engaged by the AEMC to do a quantitative review to determine whether, or the extent to which, large loads and non-intermittent non-scheduled generators contribute to inaccuracies in the regional demand forecasts for pre-dispatch and dispatch.

In the majority of dispatch intervals with large dispatch demand inaccuracy
…… there is no observable relationship with price responsive behaviour.

For some facilities, demand/supply changes align with regional dispatch demand inaccuracy and the changes are linked to price responsive behaviour.
…… Scheduling these facilities may improve dispatch accuracy.

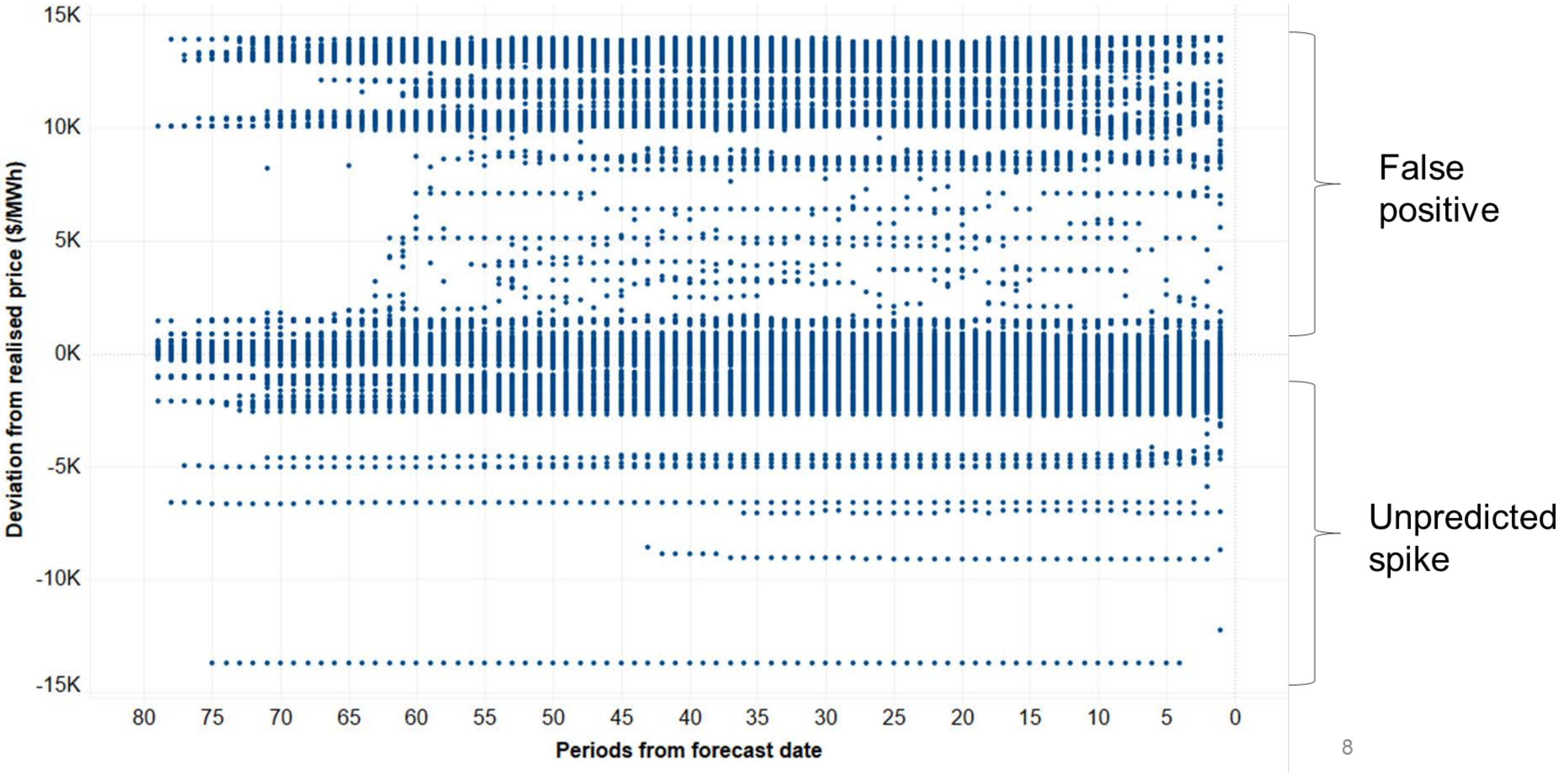
Other facilities that contribute to dispatch demand inaccuracy are highly variable in their operation at all times.
…… Scheduling such facilities may not improve dispatch accuracy.

The lack of 5 minute data for many firms in the study limited the analysis and the conclusions that could be drawn.

Evidence of distortion:
Additional quantitative analysis; 30 minute pre-dispatch

Pre-dispatch pricing varies materially from actual pricing.

Example below is data from South Australia 2016.



Evidence of distortion:
Additional quantitative analysis; 30 minute pre-dispatch

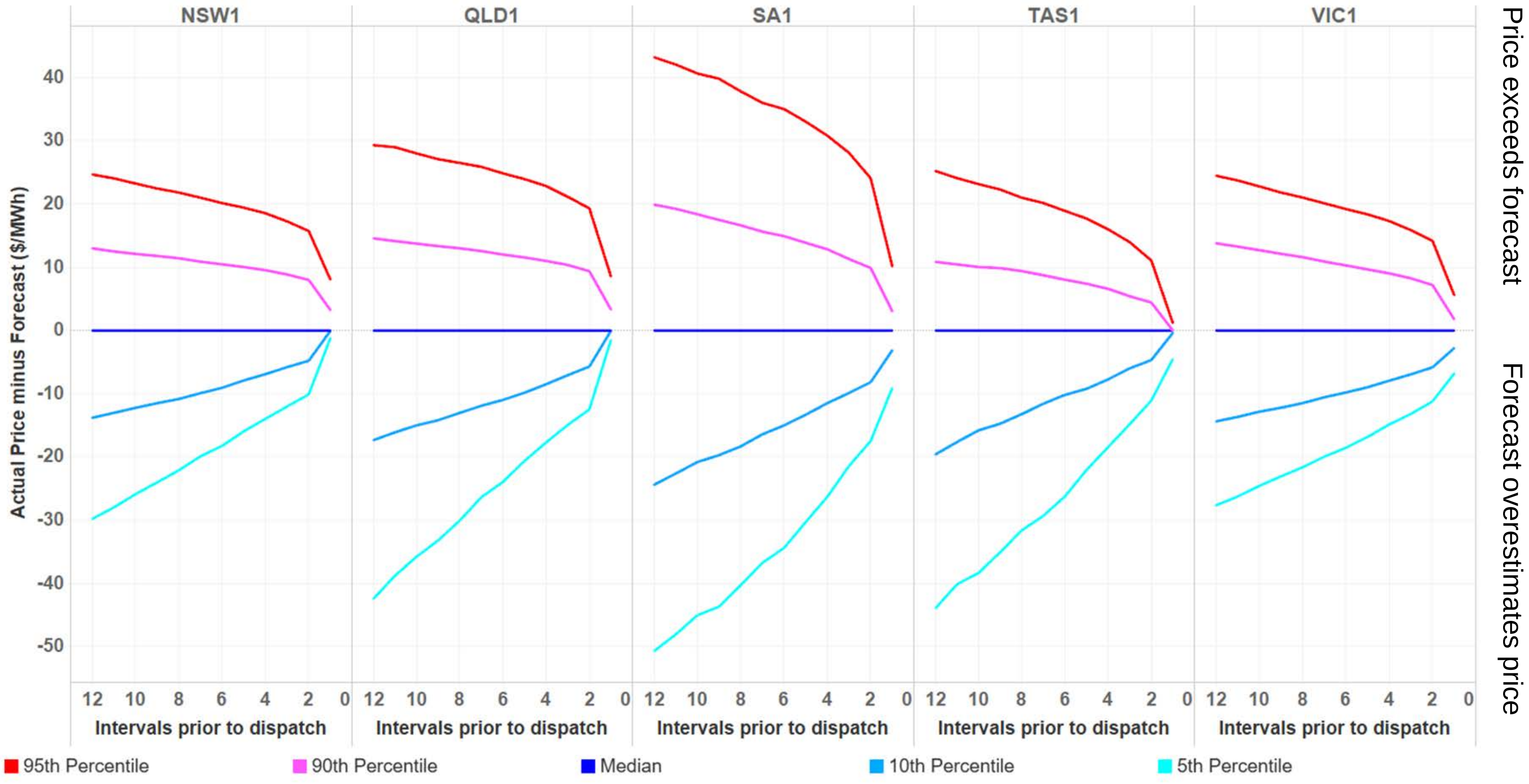
Proportion of >$1000 price spikes predicted within 20% error in pre-dispatch. Accuracy improves as dispatch nears.

	Percentage of accurately predicted high prices		
	One hour out	Four hours out	Ten hours out
NSW	77%	66%	59%
QLD	73%	61%	54%
SA	61%	46%	39%
TAS	47%	38%	33%
VIC	67%	52%	45%

Evidence of distortion:

Additional quantitative analysis; 5 minute pre-dispatch

Magnitude of forecast error varies by region.
Actual prices minus P5 forecasts by region, 1 September 2015 to 8 March 2017.



AEMO's forecasting role

- AEMO is required to estimate demand and prices for the Dispatch and the Pre-dispatch schedule.
  - AEMO's 5 minute pre-dispatch forecast is not required under the NER.
- The inputs and models that underpin the forecasts are different;
  - Dispatch and Pre-dispatch demand and price forecasts may not be aligned.
- There are a range of factors that contribute to the discrepancy between dispatch and pre-dispatch outcomes:
  - change in the generation and consumption profile of non-scheduled participants;
  - scheduled generators' rebids within a trading interval do not get incorporated into Pre-dispatch
  - there are different requirements for updating information in the Dispatch and Pre-dispatch processes.

FCAS costs, and other costs

Comparing FCAS costs and NEM revenue

FCAS payments summary	$, m	NEM revenue (AER State of the Market)	$, b
2012	$24.58	2011-12	$6.00
2013	$22.80	2012-13	$12.20
2014	$30.34	2013-14	$10.80
2015	$63.22	2014-15	$8.20
2016	$121.01	2015-16	$ 10.72*

* estimate

FCAS costs have increased from 2014-15, but attribution to the actions of non-scheduled participants is not clear. For e.g.

- In 2016, South Australian FCAS expense was $49.5m, of which over $45m was associated with upgrading the Heywood interconnector in the last third of the year.
- The Basslink interconnector being out of service coincided with the Tasmanian drought, which increased FCAS costs in H1 2016 as water prices rose and hydro services were used to provide FCAS.

- There is no data available on the costs to generators of inefficient generation attributable to the actions of non-scheduled generation or price responsive loads.
- There is also no data available on the economic loss:
  - o non-scheduled generators would incur if they were scheduled and subsequently had their output constrained; or
  - o non-scheduled loads would incur if they were constrained from being price responsive.

Conclusions:
Evidence for and materiality of issues

- The quantum of non-scheduled generation and load creates capacity for market distortions.
- There is evidence of increasing divergence between pre-dispatch and dispatch outcomes.
  - There are limited instances where divergence is attributable to the behaviour of a specific market participant.
  - The costs of divergence are not clear.
    - The private gains versus the private and public costs equation is not readily quantifiable.
  - Forecast accuracy is an issue.
    - 5 minute pre-dispatch is more accurate than 30 minute pre-dispatch.
  - Other factors may also contribute.

Summary of comments on issues analysis I

- Comments on evidence data (slides 17 – 24)
  - AER "demand" category can be customer behaviour (i.e. price responsiveness), other changes in demand, or forecast error – may be appropriate to analyse the various factors
  - On EY conclusion that scheduling "other facilities" that contribute to demand inaccuracy and are highly variable in operation may not improve dispatch
    - One view was that scheduling would address variability
    - Alternate view was that load's operational requirements, not price responsiveness, is the driver of variability, so scheduling impractical in that it would impact on industrial operation
  - Many large loads are under financial pressure from high electricity prices already. Adding additional cost may result in the business becoming financially unviable
  - There is a difference between deliberate changes to demand versus non-deliberate. Some factors will be known. If factors can be forecast they probably should be.

Summary of comments on issues analysis II

- Comments on evidence data (slides 17 – 24) continued
  - Loads are driven by operational requirements with the price of electricity only being one component. The Number of loads that price respond is limited, and they do not always respond. Therefore, do not force everyone to be scheduled when issue relates to few loads.
  - Claim that scheduled generators gaming the market and price. Response that this is not the case, the bidding in good faith rule change ensures non-gaming behaviour.
  - Focus should be on giving AEMO the tools needed to make better forecast and dispatch decisions.
  - Need to do analysis of demand forecast accuracy in addition to the pricing accuracy shown.
  - Noted that pre-dispatch and dispatch have different purposes, and therefore different inputs and modeling
  - More confidence in forecasts – whether 30 minute or 5 minute - is the essence of the rule change

Summary of comments on issues analysis III

- Comments on evidence data (slides 17 – 24) continued
  - Forecasts inform the market about supply and demand, and are intended to get a response. Why is response a problem? Some stakeholders indicated that inefficient generation may occur as a result of the response, and that more confidence in pricing outcomes would allow for greater resource optimisation.
  - Scheduled and non-scheduled generation compete for transmission capacity. It is only the scheduled generators that are constrained off when there is a transmission constraint.
  - FCAS costs will increase slowly as non-scheduled generation increases and there is a reduction in competition from FCAS providers.
  - Differing views of the impact of non-scheduled generators that sit within load facilities in relation to the materiality or distortions that result from their participation in the market
  - Less things impact demand whereas everything that occurs pre-dispatch affects price and therefore, analysis of materiality should include an examination on the impact on demand
  - Most energy users have more complex logic than minimum run times. Information would be useful to AEMO. Does not have to be 5 minute data/ forecasts.

OPTIONS FOR CHANGE

Assessment criteria

More accurate pre-dispatch and dispatch pricing:
- Better investment & operational decisions
- Lower average prices

Derivative pricing:
- Reduce prices with better information, reduced volatility & reduce forecast reliance

Improvements in market operation:
- Lower FCAS costs

Regulatory & administrative costs:
- Burden on participants if implemented

Planning benefits:
- Assist AEMO plan & procure services for safe & reliable system operation

Impact on participants:
- Changed incentives & obligations for participation in central dispatch

Context of rule change proposals

Reinforce AEMO's information gathering powers, AEMO improves its forecasting models, strengthen AEMO's abilities to schedule or otherwise control market participants.

Redraw the balance of responsibilities between AEMO and industry participants, so that all participants take a more active role in the process of balancing supply and demand.

Generation outlook:

- Smaller, more intermittent, more distributed generation

Demand outlook:

- More actively managed consumption

Further context of rule change proposals

5 minute settlement

Demand side information obligations

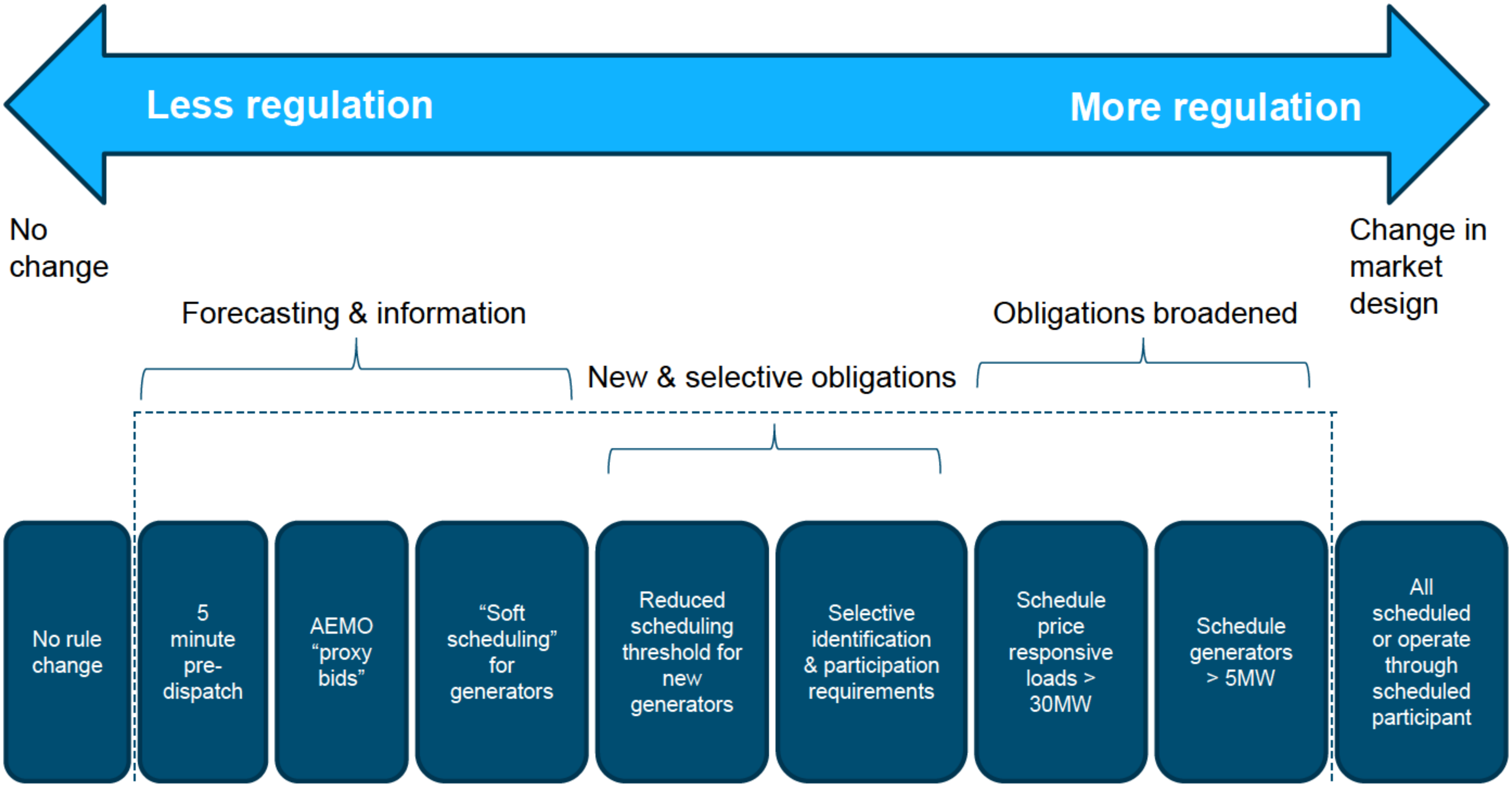
Good faith bidding requirements

Distribution Market Model

Assessed options

Proponent	Description
Snowy	Schedule loads >30MW that are or intend to be price responsive
ENGIE	Schedule non-intermittent generators >5MW
ENGIE	New “soft-scheduled” category of generators with information provision requirements
ENGIE	AEMO “proxy bids” for non-scheduled price responsive generators
AEMC	Selective identification and dispatch participation requirements
AEMC	Reduce the scheduling threshold for all new generators
AEMC	Formalise the 5 minute pre-dispatch forecast
AEMC	Change the market design

The range of potential solutions



Options assessment:

Change the market design

Criteria	Indication	Comment
More accurate pricing		• All generation and load included. • Framework applies irrespective of size.
Improved market operations		• Potentially lower FCAS costs.
Planning benefits		• Improvement in AEMO's ability to plan & procure services for safe and reliable system operation.
Derivative pricing		• Improved accuracy with industry information rather than forecasts, and less volatility.
Regulatory burden		• Major change to market design, and load "opt in" framework. • Significant increase in requirements on loads, retailers, non-scheduled generators.
Impact on participants		• Would change economics and incentives of some existing participants. • Clear framework for new entrants and investors..

Options assessment:

Schedule non-intermittent generators >5MW

Criteria	Indication	Comment
More accurate pricing		• Captures additional generation. • Does not capture loads or intermittent generation. • Near term solution. Does not capture distributed & aggregated generation.
Improved market operations		• Potentially lower FCAS costs.
Planning benefits		• Some improvement in AEMO's ability to plan & procure services for safe and reliable system operation. • Correct threshold not clear.
Derivative pricing		• Some improvement given increased information and possibly less volatility
Regulatory burden		• Will impose compliance costs on captured generators. • Potential gaming around threshold. • Improvements to economics of scheduled generators.
Impact on participants		• May prompt operation via aggregators. • May adversely affect investment incentives. • Different rights & obligations for intermittent & non-intermittent generators.

Options assessment:

Schedule loads >30MW that are or intend to be price responsive

Criteria	Indication	Comment
More accurate pricing		• Captures price responsive large loads • A reduction in demand-response may increase spot price. • Does not deal with non-scheduled generation • Near term solution
Improved market operations		• Potentially lower FCAS costs.
Planning benefits		• Some improvement in AEMO's ability to plan & Procure services for safe and reliable system operation
Derivative pricing		• Some improvement given increased information and possibly less volatility
Regulatory burden		• Complex framework to determine price responsiveness. • Compliance costs on captured loads, & may not be compatible with industrial processes. • Improvements to economics of generators.
Impact on participants		• Departure from "opt-in" market design. • May prompt market withdrawal and operation via a retailer.

Options assessment:

Selective identification & participation in dispatch

- Extend rule 3.8.2(e) to apply in relation to “market distortions”.
- Use a model based on New Zealand’s approach to industrial loads:
  - conforming nodes can be accurately forecast by the operator.
  - non-conforming nodes cannot be accurately forecast by the operator.
- Conforming nodes can make a “difference” bid if they want to be price responsive
- Non-conforming nodes have responsibilities equivalent to scheduling.
- “To the extent necessary” would enable graduated obligations to be imposed, from information provision through to full scheduling.
- A change in AEMO’s operator focus to one of assessing economic impact.

Under rule 3.8.2 (e) AEMO can require participants to participate in central dispatch to the extent necessary, if it considers such participation necessary for the system operation and security

Options assessment:

Selective identification & participation in dispatch

Criteria	Indication	Comment
More accurate pricing		• Should result in more accurate pricing, but implementation dependent on (i) adequately defining "market distortions", and (ii) creating process of identifying participants. • Need certainty that rule would be consistent with AEMO's powers under the NEL.
Improved market operations		• Benefits dependent on ability to implement option.
Planning benefits		• Benefits dependent on ability to implement option.
Derivative pricing		• Benefits dependent on ability to implement option.
Regulatory burden		• Would increase compliance requirements on identified participants, but identification would be selective and compliance graduated.
Impact on participants		• A change in AEMO's operator focus to one of assessing economic impact. • May create regulatory uncertainty. • Loads may operate via a retailer (less price response, higher spot prices).

Options assessment:

Reduce the threshold for all new generators

Criteria	Indication	Comment
More accurate pricing		• Would apply to all new generators (intermittent and non-intermittent). • Would not address existing non-scheduled generators. • Appropriate threshold level unclear and likely to need to be changed in future.
Improved market operations		• Some benefit possible, but unlikely in near term.
Planning benefits		• Some improvement possible, but unlikely in near term.
Derivative pricing		• Some improvement possible, but unlikely in near term.
Regulatory burden		• No change to existing participants. • New participants enter directly or via aggregator.
Impact on participants		• Different obligations based on when entered the market.

Options assessment:

Create new “soft-scheduled” category of generators …. and ENGIE +

Criteria	Indication / Plus	Comment
More accurate pricing		• May increase AEMO’s pre-dispatch and dispatch information. • Information from participants rather than forecast. • Does not address loads. • Information from TNSPs, DNSPs, retailers, loads, generators.
Improved market operations		• Lack of compliance requirement may mean no improvement. • Reduced / no gaming incentive for TNSPs, DNSPs, retailers.
Planning benefits		• Lack of compliance requirement may mean no improvement. • Reduced / no gaming incentive for TNSPs, DNSPs, retailers.
Derivative pricing		• Improvements dependent on whether information assists in more accurate forecasts and participant gaming is not material. • Plus option may help.
Regulatory burden		• Compliance costs with information provision should be minimal. • Broader range of participants may be required to provide information.
Impact on participants		• AEMO comments it would introduce complexity and confusion into registration process.

Options assessment:

AEMO “proxy bids”

Criteria	Indication	Comment
More accurate pricing		• AEMO considers it does not have the capability to implement the option.
Improved market operations		• No benefits assumed given AEMO’s view on ability to implement.
Planning benefits		• No benefits assumed given AEMO’s view on ability to implement.
Derivative pricing		• No benefits assumed given AEMO’s view on ability to implement.
Regulatory burden		
Impact on participants		• Participants concern that AEMO becomes a participant rather than independent market operator.

Options assessment:

Formalise the 5 minute pre-dispatch forecast

Criteria	Indication	Comment
More accurate pricing		• Makes current practice a formal requirement. • Dependent on improvements to AEMO forecasting.
Improved market operations		• Dependent on improvements to AEMO forecasting.
Planning benefits		• Dependent on improvements to AEMO forecasting.
Derivative pricing		• Dependent on improvements to AEMO forecasting.
Regulatory burden		• Dependent on whether changes to forecasting change requirements on participants.
Impact on participants		• No change.

Options that do not require rule changes

- AEMO could make a series of improvements to its forecasting, and potentially to the registration process.
  - Closer alignment between pre-dispatch and dispatch information, modelling and outputs
    - Update neural network model
    - UIGF
  - Information gathering powers
  - Apply terms and conditions to new generators to foreshadow potential compliance requirements in future

Summary of comments on options analysis

- Change the market design
  - Reference point model. Fundamental change to market design.
  - Would represent extreme intervention.
- Schedule non-intermittent generators greater than 5MW
  - Virtual generators would be included.
  - Need location information if scheduled.
  - Captures generation on-site with loads. Clarification from the rule change proponent regarding who the rule was intended to become scheduled.
  - Consider settlements and scheduling separately – i.e. Market and Non-Market generator is a settlement issue not a scheduling issue.
  - Scheduling costs discussed
    - $10m p.a. for a business to day trade only, increased costs for trading 24/7
    - The costs decrease if you contract out to third party trading desk or if the generator is part of a larger portfolio that already has a trading desk

Summary of comments on options analysis II

- Schedule price responsive loads greater than 30MW
  - Clarification of who has compliance obligation and cost. AEMO directions/AER will go to the registered participant.
  - Retailers could be captured. Therefore, they may stop providing spot exposure if they are responsible.
  - Additional retailer costs would be passed to customers.
  - Contingency gas model raised as an example. Load prepared to shed at certain price levels. It is non-binding. If load cannot shed at the time it is called, it does not get paid.
- Selective identification and graduated participation
  - Would need strict criteria about “distortion”.
  - AEMO ability/role to assess economic factors
  - Information at node level rather than participant
  - Could apply retrospectively
  - Retailer also captured in this option

Summary of comments on options analysis III

- Reduce the threshold for all new generators
  - May give a competitive advantage to existing generators over new
  - Consistent with AEMO actions in security space
  - Clear rules for new investors
  - Immediate planning benefits for DNSPs re embedded generation
  - May stop co-generation with load given scheduling costs
  - May need to review standing exemptions currently used in relation to registering a generator
- “Soft scheduled” and AEMC ENGIE Plus options
  - Options are about information
  - Behind the meter information would help AEMO forecasts
  - No incentive to participate. No compliance requirement.
  - Not too different to what occurs (in limited instances) now

Summary of comments on options analysis IV

- Proxy bids
  - Not popular option. AEMO would become a participant.
  - Error in forecasting price means there is an error in forecasting demand.
  - Demand has to respond to a signal.
  - Improve the demand forecast with better information. Capture and aggregate information at a connection point and feed into NEMDE.
  - Perhaps provide the additional information to the market rather than feed in with a price.
- Formalise the 5 minute pre-dispatch forecast
  - Opportunity for AEMO to improve accuracy of forecast
  - AEMO is looking at MTPASA to see if it can be improved.
  - Chapter 3 micro-manages AEMO. 5 minute forecast is good because it is not a formal requirement.

QUESTIONS & FINAL COMMENTS

Thank you
for your
participation