IES
Intelligent Energy Systems

13 August 2020

Mr James Hyatt, Mr Ben Hiron. M. Jessie Foran
Project Leaders
Australian Energy Market Commission

Dear Project Leaders

AEMC Ref: ERC0290: AEMC, System services rule changes, Consultation paper, 2 July 2020

Intelligent Energy Systems (IES) wishes to respond to the Consultation Paper issued by the AEMC on the above proposed rule changes.

IES is an Australian consulting and software company that has supported market reform in Australia since the mid-1980s. IES staff have advised on various aspects of market design in Australia and internationally. For example, IES designed the current ancillary service market arrangements and causer pays mechanisms in 1999-2000.

We have responded where appropriate to the specific questions listed in the consultation paper using the supplied AEMC template. This is attached as an Appendix. However, we would like to summarise our general arguments free from the constraints of such a structured questionnaire.

Are Current System Service Arrangements Adequate for the Electricity System of the Future?

We agree with the case made in many of the rule change proposals that arrangements need an overhaul. One piece of evidence cited includes the difficulty that some plants experience when deciding whether or when to commit plant. Another is the high level of AEMO intervention that is occurring now that capacity is tighter than it used to be and the dynamic behaviour of the system more uncertain.

If a plant such as a GT is uncertain about whether to commit, it probably shouldn't, at least at that time. Ideally, options better suited for the short, probably uncertain period ahead should fill the gap until the case for GT commitment becomes clearer. What is this plant? In future it will likely be plant like large scale batteries and demand-side response, including but not limited to batteries. However, behind-the-meter options continue to be stifled by the requirement for them to be scheduled, either directly if large enough, or through a retailer or aggregator otherwise.

To understand why, it is enough to focus on the use by AEMO and AEMC of loaded words like a requirement for "visibility". Translated, this means that the only options available to balance supply and demand at any timescale are those that declare themselves through the current bidding process. With a requirement for "visibility" at the forefront, AEMO appears unwilling to take account of the fact or potential for unscheduled demand-side response, either for energy or for managed, beneficial frequency response. Further, AEMC in its consultations and determinations on demand-side response appears to accept this approach without question.

Of course, AEMO does need confidence that the system will remain secure; that is its role. But spontaneous response which provided good quality information capable of use in forecasting should be a viable approach. If there is enough very short-term flexibility, not everything needs

Intelligent Energy Systems ACN 002 572 090 ABN 51 002 572 090
Head Office – Sydney Level 2, 10-12 Clarke Street, Crows Nest NSW 2065 Australia PO Box 931 Crows Nest NSW 1585
Telephone 61 2 9436 2555 **Facsimile** 61 2 9436 1218 **Email** ies@iesys.com **Web** www.iesys.com

to be scheduled and the system can be kept secure more easily than with dedicated resources willing to commit well in advance.

Are the Current Proposals Consistent with the NER i.e. a Low-cost Outcome?

We propose to make no specific comment on the system strength issues raised, nor on inertia, at least in this submission. Our comment will relate to the need to supply energy where there is a high degree of uncertainty, either well inside a DI interval (such as with the FFR proposal), or well beyond it, such as with the operational reserve and the day-ahead capacity proposals.

The proposal for FRR raises no new issues other than the matter of metering, as AGC will be inadequate for that service. It recognises that a faster response option will be helpful to limit RoCoF and manage frequency generally. The design is consistent with that for other contingency FCAS. However, IES believes that the performance for all these services, and especially primary frequency response where there is no formal FCAS product, would be greatly improved in terms of cost and technical result by adding a deviation pricing component the FCAS toolkit. As outlined below, the time constants of the different deviation price components can align with the enablement products.

The proposals involving various degrees of "aheadness" (apparently a newly invented word) are much more problematic. As noted earlier, the issues they are attempting to address are mostly real enough, although price volatility should not be considered a problem. Our focus is system security and reliability; to the extent that these outcomes might be less desirable than they could be or more costly to maintain than they should be.

The main problem with these proposals, identified by the AEMC, is determining how much and what type of plant should be committed at each of these timescales.

So, what type of plant would be available? To meet the current dispatch rules, plant must be at least a certain size or part of an aggregation of that size. Further it must be prepared to submit itself to a scheduling process. To a substantial degree, these requirements promote large, dedicated plant or retailers or aggregators who are taking a margin from the owner of the asset (thereby constraining supply).

Now focus on the requirement. We are looking ahead of a 5-minute dispatch interval – half an hour in the operational reserve case and 24 hours in the day-ahead case. At both timescales the requirement is uncertain (if it wasn't, we wouldn't have a problem). So how much reserve would AEMO require? A moment's reflection yields the answer – enough to deal with the worst case to a high degree of probability. Clearly, much of the requirement will seldom run. What type of plant? AEMO might have several categories to choose from, but clearly, it will only be plant or demand response that is prepared to submit to scheduling, not only a half hour or a day ahead, but also to provide longer term forecasts of availability as well.

We note the very poor match between the requirements to meet uncertainty and the type of plant likely to be available if required to be scheduled. Such a system could be made to work, but at a high cost.

We argue that there is another way to provide security in the face of uncertainty – deviation pricing. We do not suggest replacing an enablement process for FFR, but to add to and strengthen the FFR service. The same approach could be used to strengthen every other FCAS by rewarding performance. For the ”ahead” options, it is possible that deviation pricing could remove the need for them. However, if examination suggests that they are desirable, deviation pricing could support them by making it unnecessary to be too-conservative in setting the service requirement.

Another reform should also be considered in this context. To unlock the full potential of the demand-side, AEMC should re-examine options for promoting demand-side response without the overriding constraint that all such response be scheduled. Such options would still need to provide good response information to AEMO in a timely manner and fully support beneficial frequency as well as energy responses.

Outline of Deviation Pricing and How it can Support FCAS and any “Ahead” Arrangements

The AEMC has canvassed the concept of deviation pricing in its Frequency Control Frameworks Review. IES has ben researching the topic before and since that time and with industry partners is currently seeking an ARENA grant to work up an initial implementation: to support Primary Frequency Response (PFR) using SCADA metering.

1. The concept of deviation pricing has its roots in control theory and optimisation. This provides the theoretical basis for driving both efficiency and system stability, by managing the deviations of defined state variables from target values. Further it provides the tools make a large, highly complex system tractable and controllable.
2. The approach provides calculable control policies to keep the system stable at low cost, where those policies can be determined solely from local measurements of frequency and time error (occasionally resynchronised in the case of time error).
3. The approach also delivers prices for relevant system states. The logic can be re-expressed so that the system deviation price (for deviations from targeted levels) is driven from frequency and time error measurements and the optimal policies are functions of the components of that price
4. The components of the system deviation price are characterised by a set of time constants and gains (multipliers or weights). Broadly, these correspond the nominal times of current FCAS, as well as potential new ones such as FFR and a half hour ahead services
5. These components complement (add) to each other and can complement without adjustment all current FCAS. There is no logical basis for being concerned about double counting as income from deviation pricing would drive down the value of enablement.
6. Various adjustments to the basic theory are require to make a viable system. For example, how are the gains to be determined and is there merit in weighting the price with the local energy price to achieve geographical spread? What happens when networks separate?
7. Potentially useful additional properties of deviation pricing should also be recognised. For example, it appears that deviation settlement amounts could be relatively easily hedged in the normal energy market if weighted by the local energy price.
8. An initial (prototype or trial) implementation for PFR and potentially all slower FCAS could use SCADA data, subject to more detailed analysis of potential errors. Longer term, a suitably programmed electronic meter would deliver accurate settlement data down to the

sub-second level. IES is working on a demonstration that would illustrate how such a meter and corresponding settlements would work in practice. While the calculation volume is large, the results can be summarised for uploading and settlement purposes in a relatively few 5-minute factors.

IES commends this approach to the AEMC, either as a supplement to the current or possible future frequency control services, or as an alternative in the case of some future "ahead" proposals.

Yours sincerely

Hugh Bannister
CEO
Intelligent Energy Systems
M: 0411 408 086
E: hbannister@iesys.com
Web: www.iesys.com

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Intelligent Energy Systems

APPENDIX: Consultation paper - System services rule changes

STAKEHOLDER SUBMISSION TEMPLATE

The template below has been developed to enable stakeholders to provide their feedback on specific questions that the AEMC has identified in the Consultations paper for the System services rule changes.

The rule changes discussed in the system services consultation paper are:

- AEMO – *Primary frequency response incentive arrangements* (ERC0263)
- Hydro Tasmania — *Synchronous services markets* (ERC0290)
- Infigen Energy — *Operating reserves market* (ERC0295)
- Infigen Energy — *Fast frequency response market ancillary service* (ERC0296)
- TransGrid — *Efficient management of system strength on the power system* (ERC0300)
- Delta Electricity — *Capacity commitment mechanism for system security and reliability services* (ERC0306)
- Delta Electricity — *Introduction of ramping services* (ERC0307)

This template is designed to assist stakeholders provide valuable input on the questions the AEMC has identified in the consultation paper. However, it is not meant to restrict any other issues that stakeholders would like to provide feedback on.

Given the breadth of issues discussed in the consultation paper, it is not expected that all stakeholders respond to all the questions in this template. Rather, stakeholders are encouraged to answer any and all relevant questions.

SUBMITTER DETAILS

ORGANISATION:		Intelligent Energy Systems Pty Limited
CONTACT	**NAME:**	Hugh Bannister
	EMAIL:	hbannister@iesys.com
	PHONE:	0411 408 086

CHAPTER 1 – INTRODUCTION

Question 1: Section 1.2 & 1.3 – Current ESB & AEMO work relating to the rule change requests	
1) What are stakeholders' views on how the rule change processes should be integrated with ESB and AEMO work programs?	The current arrangements between ESB, AEMC and AEMO seem less than ideal, as AEMC is the logical body to develop a long-term view of the requirements of the market. The ESB processes are much less open than that of the AEMC and risk developing approaches from a very narrow base of expertise and world view. By default, this view could lead to de facto final solutions. However, given the current arrangements, the AEMC's approach to these rule changes appear best in the circumstances.
2) Are there any additional processes that should be closely considered by the Commission when progressing these rule change requests?	The Commission should be aware, as it no doubt is, that some of these proposed rule changes challenge the fundamental tenets of the NEM, including how investment is driven. Excessive technical conservatism will eventually revert the industry to one of tight control and high cost. Most current NEM problems have market-oriented solutions.
Question 2: Section 1.6 – Timetable for the consultation process	
1) Do stakeholders have any comments on the proposed timetable for the system services rule changes?	None

CHAPTER 3 – APPROACH

Question 3: Section 3.2 & 3.3 – Three work streams: dispatch, commitment and investment	
1) Do stakeholders agree with the AEMC's approach to grouping the rule changes, at least for initial consideration?	For initial consideration, yes. However, some proposals propose a centrally determined level of commitment whereas the current NEM expects a self-commitment. If there is a problem with self-commitment in some timeframes, AEMC should examine why and what alternatives there are. A decision to have centralised commitment will tend to lock out more dynamic and lower cost solutions that could be marshalled by other means.
2) Do stakeholders believe that Figure 3.1 captures the key issues to be considered for each rule change in each time frame?	The issues are relevant to the proposed solutions but there may be other solutions to the problems being addressed that raise a different set of issues. We will give an example later.
3) Do stakeholders have views on whether/which services should be procured in certain time frames and not others?	See above. For example, it may be possible to promote FFR without procuring it at the 5-minute timeframe or, more likely, by providing at least some of the service outside an "ahead" procurement process.

CHAPTER 4 – ASSESSMENT FRAMEWORK

Question 4: Section 4.2 – The system services objective

1) Do stakeholders agree with the AEMC's proposed system services objective being used to assess these rule changes? If not, how should it be amended or revised?	Agreed
Question 5: Section 4.3 – The planning, procuring, pricing and payment service design framework	
1) Do stakeholders agree with the '4Ps' service design framework being used to assess these rule changes?	Agreed
Question 6: Section 4.4 – Principles for assessment	
1) Do stakeholders agree with the principles proposed for assessing the rule change requests? If not, should any principles be amended, excluded or added?	Agreed, with the proviso that the world "simple" is appropriately applied. For example, a modern mobile phone is an embodiment of the most advanced technology available today yet is so simple to use that toddlers can manage one. So, in the case of these rules, the technical requirements for, say, metering, to support an approach might be relatively complex but the thing being measured may be simple and transparent.

CHAPTER 5 – THE RULE CHANGE REQUESTS

Question 7: Section 5.1 – Infigen – Fast frequency response ancillary service market	
1) What are stakeholders' views on the issues raised by Infigen in its rule change request, Fast frequency response market ancillary service?	Agreed
2) Do stakeholders agree with Infigen's view that a change to the NER is required to encourage efficient provision of FFR services in the NEM following contingency events?	Agreed
3) What are stakeholders' views on if there are any other issues or concerns in relation to frequency control in the NEM as levels of synchronous inertia decline?	For the 6 second contingency service, AEMO takes advantage of inherent system response (load relief) when determining the requirement for the service. This should also be done for FFR. Consideration should be given to arrangements that enhance the inherent, unscheduled response to an event, as long as that response enhances rather than inhibits the stability of the system with the scheduled FFR response
4) Do stakeholders consider there are alternative solutions that could be considered to improve the frequency control arrangements in the NEM for managing the risk of contingency events as the power system transforms?	We do not suggest an alternative but do suggest a supplement for FFR as well as for other forms of FCAS. With suitable metering, the concept of deviation pricing can be applied to the FFR timescale. This could be used to enhance the response, not replace the scheduled service that AEMO would seek in order to ensure adequacy. Such an approach would also substantially resolve, or at least reduce, the "who pays?" issue.
5) Do stakeholders consider that 5-minute markets for FFR ancillary services likely to be effective and efficient in the global interconnected NEM and on a regional basis?	Yes, when supplemented with suitably metered deviation pricing.

6) Do stakeholders consider Infigen's proposal will provide adequate pricing signals to drive efficient investment in FFR capability in the NEM?	Yes, when supplemented with suitably metered deviation pricing.
7) What are stakeholders' views on, if introduced, how the costs associated with any new FFR market ancillary services should be allocated?	Current FCAS contingency costs are crudely allocated – raise smeared across all generators and lower smeared across all loads, both on a pro-rate energy basis. The 1999 ancillary services project recommended that costs be allocated to the largest set of contingencies, as efficiently scheduled through the co-optimised dispatch process for the service. The requirement is dynamically set to the largest contingency. This approach was never adopted possibly because of the perception that it would "unfairly" penalise large loads and generators. However, it remains the most efficient (lowest cost) approach. If supplemented with an element of deviation pricing, some part of the service would be funded through that naturally two-side mechanism. We could then expect that competitive pressure would lower the cost of enablement; enablement would then revert to a pure "insurance" premium, at least in the case of contingency FCAS. That lower cost could then be allocated efficiently as originally proposed, with much less concern about a perceived unfair cost allocation.
8) What do stakeholders consider to be the likely costs associated with establishing two new ancillary service markets for FFR in the NEM?	FFR enablement would require an extension of already familiar logic in the dispatch engine, possibly in conjunction with other new services such as ramping. There will be IT changes required for those wishing to participate, but not large ones. The cost of deviation pricing if implemented would be spread across a range of services. It would largely be a stand-alone system and so less costly to implement than a process built on top of a legacy system.
9) What are stakeholders' views on how the proposed solution may result in any substantial adverse or unintended consequences in the NEM?	No unintended consequences likely.
10) Are there specific issues with FFR that stakeholders think should be addressed in the NER as part of the establishment of markets for FFR services?	As noted above, FFR (and other FCAS) would work best if supplemented with a usage component which measures and rewards good performance, a direct incentive that is absent now.
Question 8: Section 5.2 – Infigen – Operating reserves market	
1) Do stakeholders agree with Infigen that tight capacity conditions and increasing uncertainty in market outcomes are problems that an operating reserve would address?	Yes, but an operating reserve market of the type proposed raises fundamental market design issues and may not be the only way to achieve the desired assurance.
2) Are there alternative solutions that could be considered to address tight capacity conditions and increasing uncertainty in market outcomes?	Yes. Needed is a highly dynamic mechanism that can access flexible resources with a half-hour capability from both the supply and demand sides of the market, down to the domestic retail level. Deviation pricing has that potential, especially when combined with a more flexible approach to demand-side participation than currently exists.
3) Do stakeholders consider Infigen's proposal would provide adequate pricing signals to drive efficient use of and investment in operating reserve services now and in the future?	The concept of operative reserve encroaches on the current view that, to the extent possible, the energy market alone should deal with supply beyond the 5-minute dispatch period. An exception is the arrangement in place to support fast start (but not fast enough) plant to satisfy their technical

	requirements for start, run-up and minimum run times. However, such plants are also faced with increasingly challenging commercial decisions about whether and when to initiate a start, a challenge that might well be driving the current proposal. The risk with the current proposal is that it would tend to replace the energy price motivation of flexible plant so that it relies on enablement income. This will tend to limit the market to larger, scheduled plant or aggregators, rather than the great mass of potential that is not inclined to incur the cost (via sharing half the margin with an aggregator or retailer) and inconvenience of scheduling but which is nevertheless reliable because of diversity. Having made that point, an enablement market in operating reserve could provide a sense of security, but it would be best to supplement it with a more dynamic market in deviation energy to reduce the risks of completely killing energy market incentives.
4) How do stakeholders think separate operating reserves arrangements would affect available capacity in the spot, contracts and FCAS markets now and in the future?	As noted above, an operating reserve market would tend to displace some flexible options operating in a longer than dispatch timeframe, not well suited or inclined to be fully scheduled.
5) How do stakeholders think separate operating reserves arrangements would affect prices in the spot, contracts and FCAS markets now and in the future?	This arrangement would likely drive down prices in the energy spot market but not in the faster FCAS markets, although some plant may participate in all of them sequentially.
6) How could the design of an operating reserve market (e.g. criteria for eligible capacity) best support competitive outcomes both in the operating reserves market but also energy and FCAS markets?	If designed similarly to the other FCAS markets, it would be relatively simple in principle to operate sequentially in a number of them, depending on the technology.
7) What are the factors that should be considered when seeking to set and procure efficient levels of operating reserve?	This is difficult and a challenge for the concept. What level of reserve is adequate, which doesn't also mess with the energy spot market?
8) Would Infigen's proposed operating reserve market result in any substantial adverse or unintended consequences in the NEM?	Potentially, yet another disincentive to invest based on energy prices. As a result, the NEM will be driven more by decisions on requirements by regulatory and operating bodies than a balance of supply and demand.
9) What are the costs associated with establishing an operating reserve market in the NEM? If introduced, how should these costs be allocated?	Costs would involve changes to NEMDE and participant systems. Presumable costs would have to be smeared in a similar way as other contingency FCAS. This would be less of a problem if a deviation pricing component at this timescale could take some of the pricing burden.
10) What kind of incentive/penalty arrangements would be necessary to be confident the operating reserves procured are available when needed?	A deviation pricing component would provide a positive incentive to both scheduled and non-scheduled providers (if non-scheduled providers are allowed).
Question 9: Section 5.3 – Delta Electricity – Introduction of ramping services	
1) Do stakeholders agree with Delta that price volatility that occurs when dispatchable generators ramp through their energy bid stacks in response to predictable, daily, high rates of change from solar ramping up and down is a problem that needs addressing?	It may become a problem, but only to the extent that security is threatened and/or that AEMO intervenes frequently in response to a perceived security problem, even when that problem might be resolved in real time in other ways. Price volatility in the NEM is not a problem.

2) Do stakeholders think that a new raise and lower 30-minute FCAS would address the price volatility at these times? Are there alternatives that could be considered to address this problem?	The service would certainly reduce volatility if that is the aim. A deviation price component with a sufficiently large time constant (of order 30 minutes) would likely address this problem more efficiently, and even more so if non-scheduled option could participate. Responding to price rather than a schedule does not necessarily mean inferior performance – on the contrary.
3) Do stakeholders consider Delta's proposal would provide adequate pricing signals to drive more efficient use of and investment in ramping services thanks existing price signals and information provided through the PASA and pre-dispatch processes?	PASA and pre-dispatch are useful indictors of likely outcomes in terms of price and security, but do not drive the degree of assurance that this rule change is seeking. As noted above, if more assurance is to be provided in this way it should be supplemented with a metered and priced real time energy component as would be provided through a deviation pricing mechanism.
4) How do stakeholders think a separate 30-minute ramping product would affect available capacity in the spot, contracts and FCAS markets now and in the future?	It would substantially replace the spot market and associated contracting over that timescale.
5) How do stakeholders think a separate 30 minute ramping product would affect prices in the spot, contracts and FCAS markets, now and in the future?	This in turn could significantly reduce the role of the spot market in driving commitment and investment. Impact on FCAS markets would likely be small
6) How could the design of a ramping FCAS product (e.g. criteria for eligible capacity) support competitive outcomes in both energy and FCAS markets?	If supplemented with a deviation pricing mechanism, it could at modest cost and distortionary effect provide a degree of assurance in the market that could avert worse outcomes e.g. excessive AEMO intervention. However, the need for it is not established – reducing price volatility is not a reason.
7) What are the factors that should be considered when seeking to set and procure efficient levels of ramping services?	The proposal suggests there might be 3 products at different ramp rates, so AEMO as operator would have to choose which service it needs on the day. In other words, AEMO must outguess the market to be able to do a better job. This risks imposing higher costs on the system
8) Would Delta's proposed new 30-minute raise and lower FCAS products result in any substantial adverse or unintended consequences in the NEM?	Higher costs and a reduction, possibly fatal, of the energy market as a driver for investment.
9) What are the costs associated with establishing new 30-minute raise and lower FCAS products in the NEM? If introduced, how should these costs be allocated?	Costs of modified systems would be incurred as well as the additional costs of procuring what will likely be more than required from a limited range of options. Following current practice, these costs will be smeared over market participants, probably loads.
10) What kind of incentive/penalty arrangements would be necessary to be confident the new 30-minute raise and lower FCAS products procured are available when needed?	A deviation pricing mechanism with a pricing component at this timescale (of order half an hour) would ensure better compliance and reduce the pressure on an enablement market.
Question 10: Section 5.4 – Delta Electricity – Capacity commitment mechanism for system security and reliability	
1) Do stakeholders agree with Delta that there is an increasing risk that capacity capable of providing reserves or services may not be available at times when the power system may need them to respond to unexpected events because of increasing incentives to de-commit?	This is a real risk that must be addressed. However, a day ahead market may not be the best way. Requirements a day ahead are highly uncertain for the very reasons given, so there is a risk of overcommitment of resources.

2) Do stakeholders think that a mechanism to commit capacity one day ahead of time would deliver the reserves or services needed? Are there alternatives that could be considered to address this problem?	A better strategy may be to maximise the flexibility in the system by tapping into demand response with an incentive mechanism, while dropping the requirement for everything to be scheduled. This fetish seriously inhibits demand-side potential. Only some, not all, load response needs to be scheduled. Some combination of load response, batteries, hydro, gas turbines and, ultimately, coal commitment could carry the system through almost any situation.
3) Do stakeholders consider Delta's proposal would provide adequate pricing signals to drive more efficient use of and investment in reserves and system services?	Probably, and likely too much of the wrong, expensive kind.
4) How do stakeholders think Delta's capacity commitment payment would affect available capacity in the spot, contracts and FCAS markets now and in the future?	Not much on FCAS which operates on a different timescale. It would become the major driver for investment as spot prices would likely never rise enough to drive investment. Thus, investment will revert to a centralised decision-making process, which is likely to be conservative (expensive) focussed on schedulable (expensive) options. Such an approach is what the NEM was originally designed to avoid.
5) How do stakeholders think Delta's capacity commitment mechanism would affect prices in the spot, contracts and FCAS markets now and in the future?	As in the U.S., prices would remain relatively low, never rising to the market price cap due to the excess capacity that would always be scheduled a day ahead. The energy market would cease to be the primary driver for investment; investment would rely on centralised capacity setting decisions.
6) How would a capacity commitment mechanism and payment affect entry, exit and competition in the NEM over the short and long term?	Strongly and probably adversely.
7) What are the factors that should be considered when deciding how much capacity to commit ahead of time?	This is the key and almost unanswerable question. The other dimension is what type of capacity? Would batteries be enough? Probably not. Would GTs be enough, but is that what Delta has in mind?
8) Would Delta's proposed capacity commitment mechanism result in any substantial adverse or unintended consequences in the NEM?	The risk is reversion to an overly centralised process for driving investment and operations, likely to focus on large scale, high cost, schedulable options.
9) What are the costs associated with establishing a capacity commitment mechanism in the NEM? If introduced, how should these costs be allocated?	The costs of establishment are software development and changes at both ends. These and the much higher costs of the additional purchased capacity would no doubt be smeared across customers.
10) What kind of incentive/penalty arrangements would be necessary to be confident that the committed capacity would be available throughout the commitment period and/or when called upon?	No comment
Question 11: Section 5.5 – Hydro Tasmania – Synchronous services markets	
1) Do stakeholders consider this rule change proposal presents a viable model for the provision synchronous services? a) Could this proposed model be used to provide the essential levels of system strength (and / or inertia and voltage control) needed to maintain security and the stable operation of non-synchronous generation?	We have not reviewed this approach in any detail

b) Could this proposed model be used to provide levels of system strength (and / or inertia and voltage control) above the essential level required for security?	
2) Do stakeholders consider that the creation of a synchronous services market could have any adverse impacts on other markets in the NEM? If so, what are these impacts?	No Comment
3) Would the proposed model set out in the rule change request efficiently price and allocate costs for synchronous services in the NEM?	No Comment
4) Do stakeholders consider the model set out in the rule change request to be capable of sending price signals sufficient to encourage new investment in synchronous capacity?	No Comment
5) Do stakeholders consider the rule change provides an appropriate incentive mechanism for existing synchronous generators to make operational decisions to provide synchronous services?	No Comment
6) Do stakeholders consider the rule change provides the appropriate locational signals for the provision of synchronous generators to provide synchronous services?	No Comment
7) What do stakeholders see as the primary opportunities / limitations of the mechanism as proposed by Hydro Tasmania?	No Comment
8) Would the model proposed in the rule change request enable effective competition in the market for the provision of synchronous services?	No Comment
9) What suggestions do stakeholders have in relation to the first order changes that would be required in NEMDE to facilitate this proposal and any second order changes that may be required as a result of this rule change proposals' implementation?	No Comment
Question 12: Section 5.6 – TransGrid – Efficient management of system strength on the power system	
1) Do stakeholders consider that TransGrid's approach addresses all issues related to system strength currently experienced in the NEM?	We have no significant comment on this proposal. However, it does seem true that system strength management needs better coordination through some mechanism.
2) Do stakeholders consider that a system strength planning standard met by TNSPs would effectively and pro-actively deliver adequate system strength?	No comment
3) Do stakeholders consider TransGrid's proposal will provide useful and timely locational and financial signals to new entrants?	No comment

4) Do stakeholders agree that the 'do no harm' obligations should be removed? a) If so, do stakeholders consider an alternative mechanism is required to regulate or incentivise the minimisation of a new connecting generator's impact on the local network and proximate plant?	Yes
5) What are stakeholder's views regarding generators' being required to make a financial contribution for provision of system strength services?	No comment
6) Would stakeholders be supportive of the ownership of existing private system strength assets being transferred to TNSPs, as suggested in TransGrid's rule change request?	No comment
7) Would the proposed, TNSP-led solution to system strength result in any adverse or unintended consequences for market participants in the NEM?	No comment

CHAPTER 6 – SYSTEM STRENGTH

Question 13: Section 6.1 – Evolving the regulatory definition of system strength	
1) Do stakeholders consider that the AEMC's working description of the effects of system strength, and related problem description of system strength and its components accurately represents all elements of system strength, as experienced in the NEM?	No comment
2) If not, are there other components of system strength that the AEMC should include?	No comment
3) What measures might be used to define system strength? Is fault level the only measure that can be used practically, or are other measures available?	No comment
Question 14: Section 6.2 – Mechanisms to provide system strength above the essential levels that are necessary for security	
1) Do stakeholders consider the centrally coordinated model, as proposed by TransGrid, is the preferable option for providing system strength above the essential levels required for secure operation?	Our understanding is that system strength issues tend to be localised, so it is difficult to see how a market-based solution might work in that case. However, it's a worthy search.
2) Do stakeholders consider the decentralised, market-based model proposed by HydroTasmania to be the preferable option for providing system strength above the essential levels required for secure operation?	No comment
3) Could a hybrid of these models be used to deliver system strength above the essential level?	No comment

4) What do stakeholders perceive to be each model's strengths and weaknesses?	No comment
5) Do stakeholders consider there are other, alternative models for delivering system strength above the minimum levels required for secure operation?	No comment
6) What do stakeholders perceive to be the biggest benefits and risks to introducing a mechanism to deliver system strength above the minimum levels required for secure operation?	No comment

CHAPTER 7 – OPERATING RESERVE SERVICE

Question 15: Section 7.1 – Requirement for a dedicated in-market reserve service, mechanism or market	
1) What do stakeholders see as the key drivers or changes in the NEM that could be addressed by introducing an explicit in-market reserve arrangement?	The changes driving this proposal are real, but the solution has long term downside in that it would compromise the incentives for efficient investment, although not as much as the day ahead proposal. Specifically, it is likely to drive too much large scale, schedulable plant at the expense of lower cost options. An alternative approach is to drive strongly for flexible short-term response mechanisms by supporting multiple research projects and trials. There is a very large "behind the meter" potential, growing rather than shrinking, that could be tapped with a strong focus on efficient dynamic pricing and a loosening of the "must be centrally scheduled at all costs" rule.
2) Do stakeholders' think there is a need for an explicit in-market reserve arrangement in the NEM. If yes, do stakeholders consider the need to be permanent or transitional?	It would be better to drive for a high degree of response flexibility before implementing such a market. However, if such a market were to be introduced, a deviation pricing mechanism could ameliorate the long-term distortions to a large degree. The residual costs of the service could be regarded as an additional premium for AEMO comfort.
3) How would an explicit in-market reserve mechanism or market impact stakeholders? What would be the key benefits and costs? Would it effect stakeholders' operational or investment decisions?	Investment decisions would start to focus on this new income source so that options that don't meet technical and rigid performance requirements would be frozen out.
4) Do stakeholders see there to be an explicit need for a capacity commitment mechanism as proposed by Delta? Do stakeholders see this as a separate need to an in-market reserve service?	A deviation pricing mechanism may tap into currently unused resources and deliver the desired outcomes at lower costs. However, if absolute formal assurance is required, a combination of the two approaches could be workable. We suggest a trial of deviation pricing could help settle the best approach.
Question 16: Section 7.2 – Achieving security and reliability using dedicated in-market reserves	
1) Do stakeholders have views on whether an in-market reserve market or mechanism should solve primarily for reliability outcomes and security outcomes second? Or can this be more effectively co-optimised?	While we understand he distinction between reliability and security, the issue only arises when considering centralised approaches. In that case, some central body needs to decide how much of each type should be procured to achieve each purpose. This is problematic.
2) How do stakeholders see an explicit in-market reserve market or mechanism interacting with the existing NEM reliability framework? What are the	No comment on the current proposals.

policy design priorities for a new operating reserves arrangement that would deliver the reliability needs of the power system?	
3) How do stakeholders see an explicit in-market reserve market or mechanism interacting with the existing NEM security framework? What are the policy design priorities for a new in-market reserve market or mechanism that would deliver the security needs of the power system?	No comment on the current proposals.

CHAPTER 8 – FREQUENCY CONTROL

Question 17: Section 8.1 – Reforms related to the provision of synchronous inertia	
1) Do stakeholders consider that the issues relating to declining levels of synchronous inertia have been adequately and accurately described?	Yes
2) Are there any other issues related to the provision of synchronous inertia that have not been adequately described?	None
3) What are stakeholders' views on the approach to considering the interaction between FFR and inertia in the NEM?	Agree with the broad analysis
Question 18: Section 8.2 – Reforms related to frequency control during normal operation	
1) Do stakeholders consider that the issues relating to frequency control during normal operation have been adequately and accurately described?	Mostly – see below
2) Are there any other issues related to frequency control during normal operation that have not been adequately described?	The performance of the control system is currently poor and costs high. This is often ascribed to lack of inertia and VRE variability. The actual cause has been poorly tuned frequency control system hobbled by inadequate proportional (primary) response. The tweaking over several years of causer pays, the AGC and regulation dispatch quantities have been largely ineffectual because they have focussed on the wrong issue. The mandatory requirement for PFR capability now in place is a crude and costly mechanism that should be regarded as temporary. However, it will likely be effective technically
3) What are stakeholders' views on the proposed approach to reforming the process for the allocation of the costs of regulation services (Causer pays)?	Regulation in the NEM is normally described as that component of the frequency control arrangements where there is direct AGC control to correct any persistent frequency offset. It is allied to the integral component of a Proportional + Integral (PI) control system. However, the proportional (P) component of the system has never been specified in the NEM, as it has been assumed always present for free. This was recognised in the 1999 work on Ancillary Service market arrangements and a 4 second market using SCADA proposed to deal with it. This recommendation was initially accepted by the then market operator, NEMMCO. However, it was never implemented for reasons that are unclear, but

	likely because it was perceived as unnecessary when the initial effectiveness of the new FCAS arrangements was observed. A one-sided version of a 4 second market known as Causer Pays was also proposed and, in this case, implemented as a cost recovery mechanism for AGC regulation. It did not address the proportional (governor) component. In the process of implementation, it was further compromised in various ways, not least by cutting the temporal link between performance and payment. In our view, much effort has been wasted, continues to be wasted and is proposed to be wasted trying to tweak causer pays to fix current frequency control problems. A better approach is to accept it for what it is; an imperfect but workable cost recovery mechanism (and despite its flaws much superior to the crude smearing used for contingency cost recovery). A better approach would be research, trial and implement as quickly as possible a two-side deviation pricing approach across all timescales, beginning with Primary Frequency Reponses using SCADA. This approach could be later extended to longer and shorter timescales when appropriate settlement metering has been developed. A research programme should be initiated immediately to prototype and specify such a meter.
4) Is the level of specification of regulation services in the NER fit for purpose as the power system transforms?	See above
(PI(Question 19: Section 8.3 – Reforms related to frequency control following contingency events	
1) Do stakeholders consider that the issues relating to frequency control following contingency events have been adequately and accurately described?	Yes, but the action items in this space always seems to be to do more work, with very little in the way of concrete progress being made, other than the mandatory rule. There appear to be no concrete proposals being researched to make progress in this area, other than the Infigen proposal.
2) Are there any other issues related to frequency control following contingency events that have not been adequately described?	See above. Too much reliance on enablement and not enough on actual performance.
3) What are stakeholders' views on the best way to address the challenges to managing system frequency following contingency events, including reforms to value and reward FFR?	A deviation pricing scheme with price time constants spanning the timing of current FCAS services, FFR and perhaps half an hour (to cover operating reserves) would greatly enhance contingency FCAS performance and likely reduce costs. This scheme would not replace current or even proposed arrangements; it would complement them, not compete with them.
4) Is the level of specification for contingency services in the NER fit for purpose as the power system transforms?	No. Too much reliance on enablement and not enough on actual performance.

CHAPTER 9 – INTERACTIONS BETWEEN SYSTEM SERVICES

Question 20: Section 9.1 Technological and temporal issues for system service provision

1) What are stakeholders' views on how the arrangements for system services can be developed, to best utilise the capability of both established, as well as new and emerging technologies?	See below.
2) Do stakeholders have any initial thoughts on how the arrangements for system services can be best coordinated over dispatch, commitment and investment time frames?	The NEM original design was to build an effective spot market and to allow this to drive commitment and investment decisions, with the help of forward information and bilateral contracting. This is still a valid philosophy, at least as a starting point. When the NEM was designed in the mid-1990s, it was not practical to think of pricing at timescales of less than 5 minutes. Even 5 minutes was considered radical – half hour and one hour were more normal dispatch timescales. However, modern control theory as well as metering and communication technology are now powerful enough to support deviation pricing down to the FFR level and further. So, this, in conjunction with the energy spot market, could provide the primary commercial incentives. If control, commitment and investment incentives are still insufficient one might contemplate more centralised procurement approaches, as we do for FCAS. However, to be realistic, a deviation pricing approach can live with the current mechanisms and any newer mechanisms, and the balance between them could be determined by the market. This may be a little more costly to implement but more likely to be accepted across the board.
Question 21: Section 9.2 – Aheadness and commitment	
1) Do stakeholders agree with the characterisation of arrangements for aheadness and commitment, including the potential benefits?	Generally, agree. The benefits of co-optimisation may be illusory if the volume of a requirement is set some time ahead.
2) What are stakeholders' views on the potential downsides of introducing arrangements for commitment of capability ahead of dispatch?	Commitment a day ahead or even for shorter periods to deal with VRE variability will lead to a reliance on AEMO's probably conservative judgement. Further, the plant must be schedulable and willing to be scheduled. A day ahead market may have been a good idea 20 years ago, but less so when VRE uncertainty is becoming so dominant. However persistent AEMO intervention is also problematic.
3) Are there alternative arrangements that can reduce the increasing uncertainty associated with power system operation in the NEM?	Needed is a very deep pool of potentially responsive options available at short notice, perhaps at quite high prices (acceptable because not often used to the max). The largely untapped and growing flexible resource here is be behind-the-meter responses from batteries and easily sheddable load, much of which could be liberated if it could be driven by a deviation price rather than the firm commitment required by scheduling. Diversity solves the problem of small party variability and with suitable metering the overall response can be made transparent to AEMO and predictable. Retailers and aggregators (as distinct from advisers) take a large and ongoing share of the potential margin from customers and stifle the volume of providers as a result. Such responses need only be of relatively short duration, long enough to allow hydro and gas turbines to kick in.
Question 22: Section 9.3 – Cost recovery arrangements	

1) What are stakeholders' views on the appropriate approach to cost recovery for each of the system services discussed in this paper?	For a given cost recovery requirement, causer pays where applicable and if well implemented is the only approach that drives efficiency. The other approaches are more driven by notions of fairness or practicality. One way to reduces the burden of cost allocation is to develop two-sided markets in these services wherever possible, if not as an alternative than as complementary. For example, if deviation pricing were to be applied to all FCAS s (readily done with a single revenue meter programmed with appropriate time constants), the burden of cost recovery from enablement would be less and potentially recovered more efficiently through the logic of the dispatch engine, rather than smeared.
2) In each case, how can the cost recovery arrangements be developed to lower the overall costs of the NEM?	No comment on system strength, but see above for FCAS
Question 23: Section 9.4 – Implementation considerations	
1) What are the challenges or implications associated with implementing proposed arrangements discussed in this paper?	The impacts and workability of some of these reforms are not currently known or knowable. Alternatives need more focussed research, simulation and prototyping.
2) What are stakeholders' views on the prioritisation or staging of the reforms to address the issues discussed in this paper?	As noted above, focussed R&D, prototyping and simulation of alternative approaches such as deviation pricing should be prioritised. Where possible, trials should be carried out before commitment to a specific approach and embarking on wholesale system changes. Without adequate research, prototyping and trial, a "big bang" approach to market redesign risks failure.

Intelligent Energy Systems ACN 002 572 090 ABN 51 002 572 090
Head Office – Sydney Level 2 10-12 Clarke Street Crows Nest NSW 2065 Australia PO Box 931 Crows Nest NSW 1585
Telephone 61 2 9436 2555 Facsimile 61 2 9436 1218 Email ies@iesys.com Web www.iesys.com