29th January 2015

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Submission lodged online at: www.aemc.gov.au

Project Number: EPR0039

Dear Mr Pierce

Optional Firm Access Note: The Merits of the OFA model

Snowy Hydro Limited welcomes the opportunity to make a submission to this note. We appreciate the AEMC consulting on effectively the merits of the Optional Firm Access (OFA) model in response to the letter sent to SCER which outlined major concerns with the OFA.

Snowy Hydro does not support the continued development of the OFA model which has not been clearly articulated and is apparent no-one fully understands, has no relevance in a low demand and high oversupply environment, and contrary to what the AEMC contends increases centralisation of decision making.

Snowy Hydro supports retaining the status quo transmission framework arrangements. These existing arrangements have been performing well to date and there is no material evidence to suggest that these arrangements won't continue to work in the future. Investors require a stable and predictable period by which to make long term investment decisions.

The AEMC is seeking specific comments on the following three issues[1]:

1. The rationale for why stakeholders consider that the major problems that OFA is attempting to address are no longer relevant.

2. If the problems are no longer relevant, whether there are circumstances in which stakeholders could envision any or all of these problems becoming relevant at some time in the future? If not, why not?

3. If the problems are still relevant, any alternatives to OFA to address them, recognising that it would likely take a number of years to develop and implement any alternatives.

Issue 1: The rationale for why stakeholders consider that the major problems that OFA is attempting to address are no longer relevant

The "major" problems were never actually major. We believe that the current market design recognised competing trade-offs of contract carriage versus common carriage (open access), regional pricing versus nodal pricing, illiquid versus liquid contract markets, and setting up

[1] OFA Design and Testing Note page 3.

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arrangements for the regulation of monopolies to ensure efficient transmission investment in a competitive wholesale market.

The AEMC refers to seven (7) concerns with the efficiency of co-ordination between transmission and generation in the National Electricity Market. We will address each of these below:

1. The lack of clear and cost-reflective locational signals for generators, such that locational decisions do not take into account the resulting transmission costs.

We strongly disagree with the Commission's view that there is a lack of clear and cost-reflective locational signals for generators and therefore Long Run Incremental Cost (LRIC) prices produced from the OFA model represent an improvement on current arrangements.

The claimed efficiency of the co-optimisation between generation and transmission investment relies on the accuracy of the "baseline" transmission plan. The OFA requires a huge amount of centralisation on the part of TNSPs to derive this "baseline" transmission plan. We are highly sceptical that an accurate "stylised" baseline plan can be derived for the transmission system.

For instance, it is acknowledged by the Commission that the LRIC pricing model does not cater for stability, oscillatory or voltage constraints, does not cater for replacement costs, does not consider incremental changes, and the input costs are limited. Furthermore the baseline transmission plan not only requires demand as a major input but the TNSP would have to make assumptions on:

- The future location of new generation;
- The timing of new entrant generation;
- The future generation profiles of incumbent generators; and
- Assumptions in relation to other forms of non-network solutions such as network support and demand side response.

All these assumptions have to be made to derive a long term transmission baseline plan for each network element of a TNSP's network. We believe such a task would not only be methodologically and computationally complex but the modelling results would have a very big margin for error. We therefore have no confidence that the LRIC price model would produce any meaningful price signals that could be credibly relied on to inform investments potentially worth billions of dollars.

Secondly, we strongly disagree that current locational signals are minimal. As outlined in the Castalia report[2] the NEM has delivered over 10,000 MW of new generation since its inception. Castalia has analysed the location of these investments and concluded that there was no evidence to suggest that these investments were located in the wrong places. That is, the locational signals in the current transmission regulatory frameworks have sufficiently enabled investments to be made to co-optimise the location of generation taking into account all relevant factors including generation and transmission costs. Key points concluded from the Castalia report are reproduced below for ease of reference.

Table 2.1: New Generation Capacity in the NEM—1998 to 2012.

Region	Power Station	Owner	Date	Fuel Type	Capacity MW	Comments
QLD	Callide C	Callide JV	2001	Black Coal	900	Mine mouth power station
QLD	Millmerran	Intergen	2003	Black Coal	852	Mine mouth power station

[2] Castalia, Transmission Frameworks Review Submission, 10 October 2012.

QLD	Kogan Creek	CS Energy	2007	Black Coal	734	Mine mouth power station
NSW	Colongra	Delta	2009	OCGT	696	Adjacent to gas pipeline, old power station site
NSW	Uranquinity	Origin	2009	OCGT	652	Gas supply from NSW and Victoria
QLD	Darling Downs	Origin	2010	CCGT	618	Adjacent to transmission—supplied by 200 kilometre gas pipeline
VIC	Mortlake	Origin	2012	OCGT	536	Adjacent to transmission—supplied by 80 kilometre gas pipeline
QLD	Braemar 2	Arrow	2009	OCGT	507	Adjacent to transmission—supplied by 80 kilometre gas pipeline
QLD	Braemar 1	Braemar	2006	OCGT	470	Access to gas supply
SA	Pelican Point	International Power	2000	CCGT	461	Located close to load
QLD	Tarong North	Tarong	2002	Black Coal	443	Mine mouth power station
NSW	Tallawarra	Truenergy	2009	CCGT	441	Old power station site adjacent to gas pipeline
QLD	Swanbank E	CS Energy	2002	CCGT	360	Old power station site
VIC	Laverton North	Snowy Hydro	2006	OCGT	320	Located to minimise transmission constraints
QLD	Oakey	ERM	1999	OCGT	304	Access to gas supply
VIC	Valley Power	Snowy Hydro	2002	OCGT	303	Adjacent to existing power station
QLD	Yabula	AGL	2005	OCGT	240	Supports load in North Queensland
TAS	Tamar	Aurora Energy	2009	CCGT	208	Adjacent to major loads
SA	Quarantine	Origin	2002	OCGT	207	Access to gas supply
SA	Hallet	AGL	2002	OCGT	201	Access to gas supply
QLD	Colinsville	RATCH	1998	Black Coal	187	Supports load in North Queensland
SA	Lake Bonney	NP Power	2008	Wind	159	High quality wind resource
QLD	Yarwun	Rio Tinto	2010	Cogen	156	Waste heat utilisation
NSW	Redbank	Redbank Projects	2001	Black Coal	148	Located at source of fuel—mine tailings
VIC	Somerton	AGL	2002	OCGT	148	Received network support payments
VIC	Bogong	AGL	2010	Hydro	140	Located at existing dam site
QLD	Condamine	BG	2009	CCGT	135	Adjacent to fuel source
TAS	Bell Bay 3	Aurora Energy	2006	OCGT	120	Old power station site

For all the coal fired power stations access to low cost coal and perhaps cooling water appear to have been key drivers as all are located adjacent to low cost coal resources. While this may have necessitated additional investment in transmission infrastructure, it is likely that overall the benefits of the low cost fuel would ensure a high degree of co-optimisation.

For the gas fired power stations, there is a trend to locate adjacent to major transmission lines with short gas pipelines to the gas source—logical as, all else being equal on an energy basis, transporting gas is usually lower cost than transporting electricity. In other words, as investors must bear the cost of extending the transmission system to their fuel source—given that there aren't transmission lines at the gas field—they are choosing the least cost solution by transporting the gas to a location with good transmission access.

> *Uranquinity Power Station may not be ideally located from the electricity transmission viewpoint, but its location may have more to do with its location on the gas pipeline linking NSW and Victoria—it can readily source gas from both markets. The location of Somerton and Laverton power stations appear to have been driven largely by electricity transmission considerations—that is there appears to have been a deliberate choice to locate in transmission rich areas, again suggesting a high degree of co-optimisation has been achieved from existing locational signals. We understand that Somerton received some revenue benefit from avoided transmission costs.*
>
> *An important factor is the re-use of existing power station sites—logical as there is already transmission access and planning approvals may be less problematic. Colongra, Tallawarra and Swanbank E have all been constructed on existing sites where generation has been de-commissioned.*
>
> *Examination of the new generation investments made in the NEM does not show any obvious examples where the increased locational signals proposed under OFA would have materially altered the locational decisions made by investors. While there may be debate about some individual power stations, there is no clear trend towards demonstrably inefficient locations—given other factors such as access to low cost and secure fuel supplies—or have led to inefficient transmission investment. To put it another way, there is no reason to believe that—had OFA been in place—a different set of locational choices would have been made, resulting in lower combined transmission and generation investment.*

Laverton North is an open cycle gas turbine generator commissioned by Snowy Hydro in 2006. This generation development was listed in the Castalia report (table 2.1 above). We highlight this particular investment because Snowy Hydro's locational decision to locate at Laverton North in Victoria was co-optimised with consideration of both transmission and generation costs. As part of locating Laverton power station Snowy Hydro agreed to pay for Brooklyn reactors on the Victorian shared transmission network. This material investment in a deep connection asset was made by Snowy Hydro even though we received no explicit rights to the shared transmission network.

This is a great example of a Market Participant making logical locational investment decisions which are co-optimised with consideration of both transmission and generation costs under the current transmission regulatory frameworks.

Points 2 and 3 are closely related and hence we will address them together.

2. TNSPs estimating the benefits of transmission development, where those benefits are better known to generators, and the risk of inefficient decisions being borne by consumers rather than the decision-maker;

3. The resultant planning of transmission networks not being co-optimised to minimise the combined costs of generation and transmission;

There is no evidence presented that the Regulatory Investment Test – Transmission (RIT-T) is deficient such that: (1) transmission investment is given preferential treatment over generation investment, or (2) transmission investment proceeds even though it's inefficient[3]

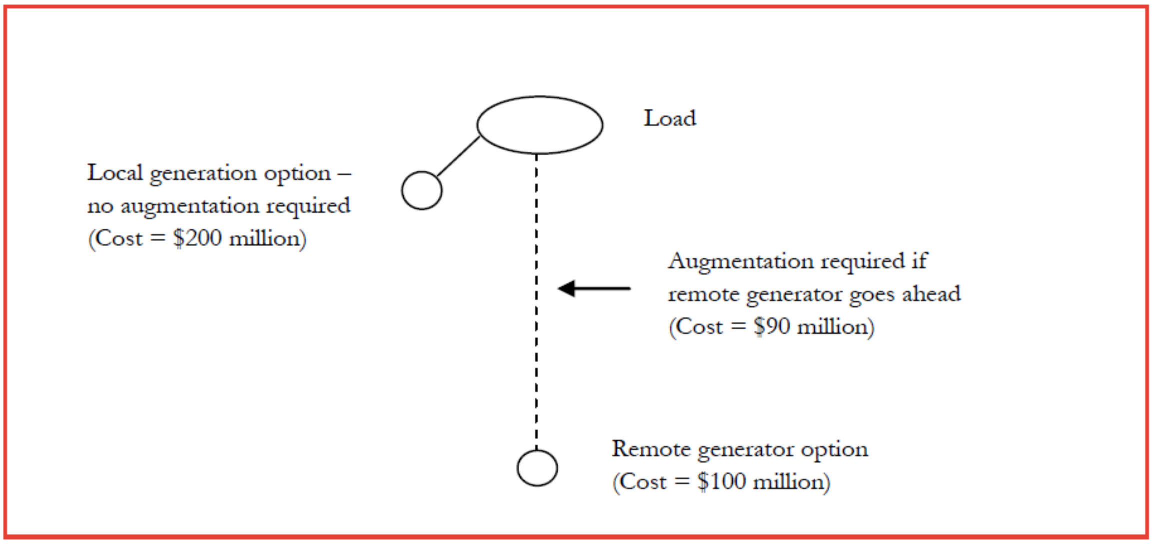
We refer to the example provided by Frontier Economics[4] that locational signals provided by the RIT-T are more powerful than is commonly assumed.

[3] With the exception of transmission investment to meet statutory reliability obligations.
[4] Frontier Economics, OFA – A report prepared for the NGF, October 2012 section 2.1.2

In section 2.1.2 of this report Frontier Economics highlights that:

- Under the RIT-T, the TNSP needs to compare the combined cost of generation and transmission at the remote location with the cost of generation at the local location.
- Contrary to the view expressed by the AEMC, the TNSP does not simply consider which option yields the lowest transmission cost. This is because under the RIT-T, a TNSP needs to consider the full 'market benefits' of an augmentation option and its alternatives.
- In the context of the example (replicated in Figure 1 below), the TNSP needs to consider which option yields the larger net market benefit or the smaller net market cost, taking into account the total costs of transmission and generation (as well as other variables such as the degree of load shedding etc).

Figure 1: Locational signals from the RIT-T



Source: Frontier Economics

Given the example figures above, the TNSP would find that it was appropriate to undertake the augmentation because the combined generation and transmission cost of power from the remote option ($190 million) was lower than the cost of power from the local generation option ($200 million) – see Table 1.

Table 1: Transmission versus local generation – relative costs

Option	Includes	Total component costs ($m)	Total option costs ($m)
Transmission	Augmentation	90	190
	Remote generation	100	
Generation	Local generation	200	200

Source: Frontier Economics

The proponent of a generation investment would have an incentive to make such calculations internally, even before the RIT-T was applied to the augmentation by the TNSP. For example, before investing in the remote generation option, a proponent would have an incentive to conduct the analysis to gain some confidence that the augmentation would satisfy the test and proceed. Likewise, before investing in the local option, an investor would have an incentive to conduct the analysis. In doing so, it would find that it was not worthwhile to develop the local option, as the augmentation (along with the remote generator option) would be likely to go ahead and harm its proposed project.

Frontier Economics concludes that:

> *In this way, prospective investors' expectations of how the RIT-T will be applied in the short and the long terms should provide investors with positive (albeit imperfect) locational signals.*

The other important point to note is that the RIT-T involves an extensive and transparent consultation process where all Stakeholders can examine and provide critique of the analysis. This helps ensure the conclusions from a RIT-T consultation are credible.

4. The importance of TNSP's operating their networks to maximise availability when it is most valuable, and the challenge they face in doing so given the lack of exposure to the financial costs of reductions in capacity.

TNSPs are already incentivised through the Service Target Performance Incentive Scheme (STPIS) and the Network Capability Incentive Parameter Action Plan (NCIPAP) to maximise the availability of their network when is of most value to the market. Over time incremental changes can be made to these incentive schemes to improve their effectiveness. Snowy Hydro hence does not understand why the OFA model would be required as a pre-requisite to provide this incentive which already exists. We also note that the proposed incentive regime for TNSPs under the OFA are muted at best with nested caps limiting their exposure.

5. The difficulty that market participants have in managing the risk of price differences between different regions of the NEM, with a resulting negative impact on the level of contracting between generators and retailers in different regions.

We note that firm inter-regional hedges are already available and achievable now with plain vanilla financial instruments. Contract traders already use these liquid financial instruments which are traded on daily basis to achieve 100% firm hedges across different pricing regions. Hence there is no evidence to suggest that the issuance of long-term inter-regional access is required or that it would improve the availability of an already liquid and competitive market for inter-regional hedges.

We also note that inter-regional products are only used at the margin to help mitigate the risk of sold forward hedges. This observation is backed by ACCC's analysis to the Australian Competition Tribunal with respect to the AGL acquisition of Macquarie Generation[5].

Under the OFA model this inter-regional product may be slightly firmer but this won't mean more contracted volume is available to the market as trading across regions is inherently more riskier and costlier that trading within your own pricing region.

[5] ACCC's Report to the Australian Competition Tribunal, File No.1 of 2014.

6. The lack of certainty of dispatch faced by generators when there is congestion, compounded by the inability of generators to obtain firm access, even where they fund augmentations of the transmission network.

Dispatch risk is present in the current market model but dispatch risk is also present in the OFA.

Under current market arrangements there is a well-defined method of allocating transmission capacity where generators bid to the Market Floor Price and in doing so share in the limited transmission access. There is no basis risk as the generator receives the Regional Reference Node (RRN) price when it is dispatched. In contrast under the OFA there is still volume risk as dispatch is not guaranteed and there is additionally basis risk if a proportion of a generators output is priced at its Local price. Hence we don't agree with the statement[6] that, "under optional firm access generators are trading (existing) volume risk for basis risk." Volume risk for generators remains in the OFA model and there is additional basis risk. This additional basis risk in our opinion would adversely impact the functionality and liquidity of the Contract markets.

7. The resulting incentives for generators to offer electricity in a non-cost reflective manner in the presence of congestion.

AEMO's modelling on Access settlement has shown that at least five other major factors influence dispatch to which OFA Access settlement has no influence to change incentives. It is therefore questionable whether there would be any improvement in efficient dispatch and in fact the presence of Access rights in the OFA model may worsen incentives to offer electricity in a non-cost reflective manner. Any questionable improvement in dispatch would be negligible compared to the adverse impact on the hedge markets by introducing basis pricing risk.

Issue 2: If the problems are no longer relevant, whether there are circumstances in which stakeholders could envision any or all of these problems becoming relevant at some time in the future? If not, why not?

As highlighted in our response to Issue 1 the "problems" were never material in the first place. These "problems" were well known trade-offs in the National Electricity Market design.

Additionally the following contextual factors that exist in the market simply do not support the need for the OFA model:

- There is overinvestment in generation;
- There is overinvestment in transmission and distribution;
- Demand and energy growth has stalled;
- The wholesale energy price and forward contract prices are insufficient to make any new large scale generation investment financially viable; and
- The prospect of new large scale generation investment as a result of the large scale Renewable Energy Target is remote irrespective of whether or not the current fixed targets are reduced to the "true" 20% because the sum of total revenues from Large Scale Certificates and the wholesale energy price is insufficient to make these new entrants viable; and

[6] AEMC OFA First Interim Report, page 23.

- AEMO through their responsibility to publish the Statement of Opportunity for 2014 has concluded that no new generation investment is required for at least another 10 years.

The OFA model if implemented in the current state of contextual factors would simply result in more regulatory risk, more inefficient transmission build, adverse impacts to the hedge markets, arbitrary wealth transfers amongst incumbent generators, and massive costs for incumbent generators who would receive a level of transitional access which would be significantly lower than the implicit access that they currently have in the NEM.

At the same time, the OFA model's direct implementation and operational costs will be significant.

Issue 3: If the problems are still relevant, any alternatives to OFA to address them, recognising that it would likely take a number of years to develop and implement any alternatives.

As highlighted we believe there are no "problems" with the current market design but "trade-offs" which exist. These impact of these trade-offs could be minimised through incremental changes instead of alternative "models" which implies major change is required. Some of these incremental changes worthy of consideration include:

- RIT-T applied by an independent party and not by TNSPs; and
- STPIS continuous improvement approach with more history to assess the performance of the incentive regimes and to make changes where necessary. We note this is already happening with rolling average targets.

Conclusion - Snowy Hydro supports the status quo

In summary Snowy Hydro supports the current transmission regulatory frameworks. The status quo (with minor improvements) is the best market design given the necessary competing trade-offs. The current regulatory frameworks are working:

- The RIT-T already sends powerful signals for new generator and transmission investment. That is there already exists a high level of co-optimisation;

- The hedge markets are functioning satisfactorily and are enabling a high degree of competition in the Retail market by providing all Retailers (especially second tiered Retailers) with competitive prices and sufficient volumes to manage their risks;

- TNSP incentives can be sharpen by modifying the numerous incentive schemes; and

- In regard to disorderly bidding, we have shown in other submissions that transmission outages are the root cause of market volatility. Previous and numerous studies have concluded that the resource cost of all forms of disorderly bidding is immaterial, and in any event the OFA proposal may change incentives for generators to bid disorderly, but not necessarily reduce those incentives or the resource cost in total.

In conclusion we do not support the OFA model. We have shown that the current locational signals already ensure co-optimisation of generation and transmission investment. The OFA with its multi layered complexity, stylistic LRIC prices which may inaccurately represent actual transmission costs, unknown implementation risks, negative impacts on the Contract markets, and ambiguous impacts to Spot market behaviour means the case for fundamental market redesign has not been made. We strongly advocate a firm recommendation from the AEMC to cease any further development of the OFA.

Snowy Hydro appreciates the opportunity to respond to this OFA note. I can be contacted on (02) 9278 1862 if you would like to discuss any issue associated with this submission.

Yours sincerely,

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