stanwell

4 September 2014

Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

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Dear Mr Pierce

Stanwell Corporation Limited (Stanwell) welcomes the opportunity to comment on the First interim report into Optional Firm Access, Design and Testing, as published by the AEMC on 24 July 2014.

We consider that the development of OFA design since it was proposed in the Transmission Frameworks Review has exposed the complexity and ineffectiveness of the proposal to fundamentally change NEM design.

While we continue to engage with the AEMC and AEMO processes which are developing the proposal, we now consider that the cost benefit assessment due in November 2014 must conclusively show that the proposal should not proceed.

Attached is a detailed response to the first interim report.

We would welcome the opportunity discuss the matters raised in this submission. Please contract Luke Van Boeckel on (07) 3228 4529 should you wish to discuss this submission.

Yours sincerely

T. Mills

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create. generate. innovate.

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OPTIONAL FIRM ACCESS
RESPONSE TO AEMC 1ST INTERIM REPORT

SEPTEMBER 2014

Stanwell Corporation Limited
ABN 37 078 848 674

1 Executive Summary

Stanwell welcomes the chance to respond to the commissions' first interim report on Optional Firm Access, Design and Testing.

At the conclusion of the Transmissions Frameworks Review (TFR) Stanwell considered that although some areas for possible improvement had been identified, a case for substantive change had not been made. Stanwell also considered that some of the areas of concern such as disorderly bidding in the presence of congestion were an issue of marginal impact to the market and for which the effort to address would far exceed any potential benefit. Regardless of the validity or otherwise of the supporting rationale, Stanwell considered that the proposed solution of Optional Firm Access (OFA) would be unlikely to address the concerns that had been raised during TFR.

We also note that as OFA arose from TRF, TFR arose from the Review of Energy Market Frameworks in light of Climate Change Policies which ran from August 2008 to October 2009. That review included in its Terms of Reference "*MCE does not anticipate that this review will result in fundamental revision of market designs or impede the effectiveness of the access regimes…*". The TFR final report suggesting OFA notes "*Implementing it would represent a fundamental change to the market, and would not be without risk*". While Stanwell does not consider that the former expressly prohibits the latter, we consider it a useful context as to how, over time, processes can morph away from MCE (now the COAG Energy Council) expectations.

The model presented in the first interim report has not convinced Stanwell that OFA will be effective or beneficial. Rather we feel that the current process reflects an escalating level of complexity with no significant benefits. Stanwell agree with the commission "*that where arrangements are complex to administer, difficult to understand, or impose unnecessary risks, they are less likely to achieve their intended ends, or will do so at a higher cost.*"

While we acknowledge that some elements of market design contain inefficiencies and inconsistencies, we consider that the proposed model is unlikely to address many of these areas while introducing new areas of concern and contribute further to regulatory uncertainty which has significant impacts for an industry which is capital intensive and has long life assets.

We note that independent work performed to date has confirmed that the wholesale market has proven effective in delivering competitive outcomes and that the identified inefficiencies are at the extreme margin. With respect to transmission planning and investment, incremental changes enacted in recent years have not yet had a chance to be evaluated fully but appear to be driving some efficiency improvements.

In general we consider that there are likely to be simpler, more effective measures that could be used to address many issues if required.

We also consider that in light of market evolutions currently taking place, the current proposal to have OFA implemented some time around 2022 is likely to mean that the model is superseded prior to implementation.

We also believe that the first interim report contains a number of recommendations that are inconsistent with core elements of the terms of reference but which have not been submitted to the Energy Council for consideration. It is important to recognise that in order to evaluate related or dependent design elements it has been necessary to assume proposed changes to the model, this however should in no way be seen as endorsement of these elements or the overall OFA proposals.

Firm Access Standard

The first interim report proposes that the Firm Access Standard encompass both a planning and operational standard whereas the terms of reference explicitly state that the Firm Access Standard is an operational standard rather than a planning standard.

We believe that the concurrent operation of two planning standards (FAPS and reliability standard) is extremely unlikely to produce a network which is less costly than the operation of a single standard. While the proposed model may reduce explicit customer payments relating to the network this will be because significant cost recovery will be moved to the wholesale market meaning consumers will still ultimately pay but will lose transparency.

The planning standard is proposed to be a deterministic standard applying to peak flows on the network, however the definition of “peak flows” remains vague. Stanwell believe that there is a risk that implementing a new deterministic standard risks embedding (or embedding further) the inefficiencies identified by the Productivity Commission in its June 2013 report on electricity network regulation. The first interim report notes that the planning standard will be all but unenforceable due to the asymmetry of information and the complexity and subjectivity of the modelling and assumptions.

The proposed Firm Access Operational Standard (FAOS) is the element that will determine the value of firm access to purchasers and therefore requires an incentive and/or penalty scheme to allow enforcement as discussed below. The operational standard and associated incentive scheme must provide robust value protection to purchasers of firm access, otherwise the basis of OFA will be undermined as generators will not be incentivised to purchase firm access.

TNSP incentive scheme

The proposed incentive scheme is extremely weak and will allocate the overwhelming majority of market risk to generators despite the procurement of firm access being intended to mitigate such risk. The proposed incentive scheme is significantly diluted from what was proposed in the TFR.

It is proposed that when the purchased amount of firm access is not provided, the TNSP would only be obliged to pay an (as yet) undefined portion of the cost accruing to the generator(s) as a result of this standard breach, and that such payments would be further subject to “nested caps” relating to the entire network – not just the network relevant to the affected generator. In addition to creating financial stress for the affected generator, this arrangement risks being opaque and un-forecastable for the generator meaning that real time commercial strategy will be compromised. The ability to implement and manage such a strategy is a basic feature of the NEM.

It is further proposed that the incentive scheme be symmetrical, which was not part of the TFR proposed design. This would mean that a TNSP who delivered less than the contracted amount of access, but more than some theoretically efficient value would receive a performance payment from the very generators who have not been provided the contracted service. Only in the event that the service provision was less than the theoretically efficient level would holders of firm access receive compensation from the TNSP. Given that the TNSP is proposed to be responsible for pricing, planning and provision of the service, Stanwell consider this design to be outrageously unbalanced.

Inter-regional Access

There is a proposal to replace the current flow based inter-regional product with a capacity based inter-regional product as part of OFA. It is claimed that this alteration will improve the ability for participants to trade inter-regionally using the existing interconnectors as well as give rise to investment signals for new interconnector capacity.

In relation to existing interconnector capacity it appears likely that in the early years of OFA there would be little or no ability to secure firm inter-regional allocation, while in subsequent periods issuance of inter regional capacity may be significantly more complex than issuance of intra-regional capacity and would therefore likely be at a disadvantage.

Independent analysis performed for the AEMC during the TFR indicated that based on experience in other jurisdictions with similar regulatory environments to OFA there is limited appetite for the commissioning of merchant transmission elements between pricing regions. We note that there has been limited penetration of merchant interconnectors during the operation of the NEM and that the majority of previously merchant interconnectors are now regulated.

Stanwell also believe that the barrier to inter regional trade under current arrangements is overstated. Many NEM retailers (including Stanwell) operate in multiple regions regardless of whether they have generation assets, and many NEM generators (including Stanwell) will sell contracts outside the regions in which they have generation assets. The decision to perform such activities is one for the relevant companies who are in the best position to evaluate the risk/reward in each case.

Short term Access

The proposed OFA model allows for firm access to be issued for periods prior to which an augmentation could occur. This access could be provided from existing, unsold network capacity, additional capacity arising from TNSP operational decisions or from existing firm access holders.

While generally consistent with the issuance of long term access discussed above, Stanwell believe there are additional issues to be resolved relating to the relevance of FAPS within that “investment shadow” including:

- the definition of the source of the access and associated revenue allocation; and
- the dilutive effect of issuing short term access on long term access holders.

Transitional Access

While consideration of transitional access arrangements are largely academic at this stage of OFA design and testing, Stanwell support the proposal to have an initial allocation that reflects the implicit access level provided to incumbent generators under the current arrangements as this is consistent with the basis of the investments.

We do not support the commissions’ progression of the transitional access sculpting model which was an “optional” element of OFA in the TFR. Stanwell believes that there are more appropriate approaches which can ensure that incumbent generators are minimally affected by the proposed fundamental change to market design while not requiring consumers to fund (further) unnecessary investment in transmission infrastructure.

We also consider that should the commission recommend that OFA proceed there are a number of over-simplifications in the initial allocation model which should be addressed in order to reduce the distortions present in the sample allocation performed by AEMO.

Reliability Access

Appendix A to the first interim report suggests changes to the RIT-T process to include a "contingent auction" of access that arises from reliability upgrades. Stanwell believe that this is in direct contradiction to the terms of reference, will increase complexity and delays in commissioning reliability augmentations and may lead to significantly larger networks than would otherwise be the case.

In the example provided the proposed process results in $280 million in transmission infrastructure being built in preference to a $100 million reliability upgrade. Stanwell does not believe that such an outcome would be in participants or consumers interests.

Complexities identified during development

We note with some concern the fundamental issues raised by AEMO in their corresponding interim report as well as the sheer amount of further work required within the AEMC terms of reference. There have also been issues identified in relation to metering arrangements which Stanwell believe have not been adequately addressed to date.

With the supplementary pricing report (now expected in late September or October) only extending to thermal augmentations but likely to confirm the cost of OFA to be in the order of hundreds of dollars per kilowatt (hundreds of millions per site for most existing large generators), we anticipate the commission's assessment of costs and benefits due in November 2014 will support Stanwell's view that the proposed OFA model should not be progressed being neither effective or beneficial.

2 Assessment Framework (1st Interim Report: Chapter 3)

2.1 Stanwell comments

Stanwell consider that the 9 categories of impact identified in section 3.5 of the first interim report constitute a sound basis for evaluating whether the introduction of OFA would benefit the NEO.

Stanwell does however hold some concern that the commission may have difficulty being fully objective in their assessment of the costs and benefits of OFA given their acknowledged "ownership" of the concept and process. We encourage the commission to regularly "take a step back" and consider the proposal against basic principles as well as the detailed analysis.

While we acknowledge that the ultimate assessment and recommendation are scheduled for the second interim report in November 2014, we disagree with significant elements of the AEMC position presented in chapter 3 of the first interim report.

Financial certainty for generators (section 3.5.1)

Stanwell broadly support the background information contained in this section with the exception of the assumption that increased financial certainty would *"…increase the willingness of generators to offer contracts…"*. We believe that generators are more likely to be limited by physical risk and/or the relative value of market price to cost structures than congestion risk. Since a generator with firm access and sold contracts would still be exposed to its local price in the event of an outage, firm access may not alleviate the physical plant risk at a given market price[1] . We also note that a decrease in financial certainty would be expected to lead to a higher risk adjusted cost of capital.

With regard to insurance products, non-firm products have been offered and transacted throughout the history of the NEM, although in many instances the discount expected from the buyer for taking on this risk has made transactions prohibitive for sellers. This is logically consistent since if congestion is present at times of high price it is likely to exacerbate that price (assuming it is not in fact the primary cause) and contract cover which decreases in volume as price increases is likely to be a poor hedge. Stanwell considers that OFA provides the same structure as non-firm hedges but with generators as the buying party – that is, in the event that congestion exists at times of high reference prices, any scaling of access would mean that firm access has provided a poor hedge.

When combining the additional fixed cost of firm access, the retained exposure to spot pricing during times of outage and the non firm characteristics of firm access, Stanwell does not consider it likely that generators would have significant incentive to either hedge more volume or sell at lower prices as indicated by the commission.

In relation to financing costs, Stanwell disputes the assumption that holders of firm access would receive lower risk adjusted cost of capital when compared to the current arrangements.

- Under current arrangements refinancing processes are likely to examine forecast time-weighted and dispatch-weighted pricing for "reasonableness" and then apply sensitivity cases to these forecasts to determine the robustness of the business to changes in price from any source – congestion or otherwise. Given the volatile nature of spot prices even

[1] Additionally, in the event of an outage, congestion between the plant and the regional node becomes less likely meaning that the local price is equal to the reference price and access settlements are unlikely to provide mitigation.

on an annual average basis such approximation tends to produce a reasonably comprehensive picture of the merits of the investment.

- Under OFA it is likely that a similar analysis would be performed with one possible additional consideration – the terms of firm access. This would include the cost of firm access, the volume and forecast "firmness".
    - o Generators with firm access levels which are considered sufficient to justify the time weighted to dispatch weighted price difference would likely receive pricing on similar terms to current investments, assuming the modelled prices reflect recovery of the additional cost.
    - o Generators with insufficient firm access, low forecast pass through of firm access costs or whose access was considered to have low correlation to peak pricing would likely have to pay a premium to current arrangements.

Stanwell also consider that the example provided in section 3.3.1 of the TFR final report shows that holding firm access does not mean that a generator is less affected by network reductions than a non firm generator. Stanwell believe that this simplified example highlights the limited positive impact of firm access in relation to generator financial certainty.

Figure 3.2 Two-node network example

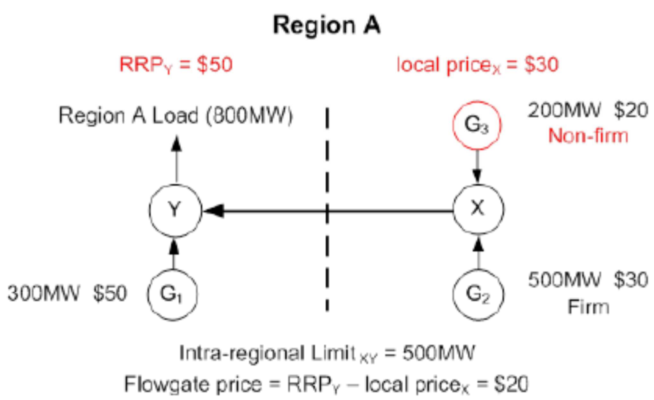

***Figure 1 Simplified example of OFA from TFR final report, page 32*.**

- In the example generator G2 has firm access sufficient to allow complete access to the node under normal conditions.
- The example shows that G2 receives the same operating margin with and without congestion (ignoring long run considerations including the cost of purchasing firm access).
- What is not addressed is the impact of access scaling. Assuming all else remains equal, for the first 300MW of access derating G2 would lose both dispatch (based on offer price) and access (due to scaling) while the non firm generator G1 is unaffected.
- The example also does not examine the incentives for generator bidding under firm access. For example, G2 is incentivised to "disorderly bid" 300-499MW to $20 or lower under constrained conditions to maximise its margin at cost to G3.

Effective interregional hedging (section 3.5.2)

Stanwell agree that participants and consumers benefit from inter-regional linkages in the NEM. We also agree that SRA units provide a partial hedge for inter-regional exposures, however we consider that financial contracts, weather derivatives and other contingent products can also be used to mitigate inter-regional exposures if this is considered desirable.

Of the four "problems with the existing arrangements" enunciated on page 24, Stanwell consider that at least one will not be affected by the introduction of OFA[2], and one will only be effective in the event that the interconnector (or rather a participant(s) using the interconnector term in constraint formulas) holds firm access[3].

We consider that access settlement may require further definition in relation to interconnectors. For example assuming that flowgate usage is proportional to interconnector flow and access is only affected by physical and security network limitations[4]:

- if there is no or partial access agreements in relation to an interconnector that is flowing into a constrained area who pays into access settlement on behalf of the interconnector for flow above that access level? As regulated interconnectors do not bid on their own behalf, would it be generators in the exporting region and which ones?
- If counter price flows are occurring, does the interconnector receive a zero or negative usage value for access settlements? Either approach will have ramifications.

Stanwell also question the robustness of the assumption that "*generators located in lower-priced regions should be better able to contract with retailers in higher-priced regions, with resulting benefits to consumers in higher-priced regions*". This assumes that the cost of procuring firm inter-regional access is less than the benefit of holding access, that the generator will pass this saving to the retailer, that the retailer will pass this saving to the customer and that similar risk mitigation is not available through existing market structures such as financial contracts, SRAs or contingent derivatives.

Efficient incentives on TNSPs to operate the network (section 3.5.3)

Stanwell agree that TNSPs should aim to provide network capacity at times that the market values it most highly, and that a financial incentive scheme is likely to be required to maximise such behaviour. We also agree that the market impact component of the Service Target Performance Incentive Scheme (STIPS) has had some success at changing TNSP behaviour despite its relatively low power.

We agree with the rationale contained under the "positive impacts" under OFA, but as will be detailed in subsequent sections, we do not believe that the proposed incentive scheme is appropriate.

In addition to the "issues to investigate" listed in section 3.5.3 Stanwell believe that the impact of network performances on notionally firm generators should be considered – not just the impact on TNSP payments.

Efficient dispatch of generation (section 3.5.4)

Stanwell support the commission's commentary regarding markets driving efficiency where it applies over the medium to long term, however note that short term inefficiencies do not mean the market is not operating efficiently. We believe this distinction is supported by the commission based on comments made in other forums[5].

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[2] "*If the interconnector's available capacity is reduced (eg due to outages) then flows, and therefore residues will be reduced*". Stanwell consider that access sculpting would have the same effect.

[3] A generator evaluating the cost of locating on the interconnector flow path will receive a low cost indication if existing capacity is not secured under firm access agreements.

[4] In many cases interconnector limits in NEMDE represent financial limits arising from the objective function rather than physical limits.

[5] Stanwell consider that this topic was covered comprehensively in AEMC 2013, *Potential Generator Market Power in the NEM, Final Rule Determination*, 26 April 2013, Sydney

We agree with the commission that where the procurement of firm access does not reflect efficient dispatch, OFA may cause, or lock in, a loss of productive efficiency.

We do not consider that the introduction of OFA will have a material impact on the efficiency concerns noted by the commission in this section – namely disorderly bidding during network congestion and late strategic rebidding:

- We have already shown in relation to generator financial certainty above that disorderly rebidding incentives remain in place under OFA – albeit with slightly different circumstances and application.
- In relation to late strategic rebidding, Stanwell is unaware of any proposed benefits relating to the introduction of OFA.

While a reduction in wholesale price volatility is generally considered a benefit in the first interim report[6], Stanwell notes that while some generators are disadvantaged by particular constraints binding, other generators benefit from reduced competition resulting in higher prices. Were these generators not exposed to these higher prices they may become unprofitable (if they are not already so) or attempt to increase their revenue and/or margin at other times.

Efficient incentives on TNSPs to manage trade-offs between operation and investment (section 3.5.5)

Stanwell does not consider that the proposed OFA model will provide the ability for TNSPs to manage trade-offs between operation and investment in the planning domain. The TNSP will be required to plan to provide all firm access concurrently. Stanwell is not aware of a proposed ability for a TNSP to deliberately plan to not provide a portion of firm access due to the cost of doing so being greater than the cost of operation. In fact such deliberate, documented action may be the only way that the Firm Access Planning Standard becomes enforceable and is therefore even more unlikely to be conducted by TNSPs.

In the operational timeframe Stanwell understands that TNSPs will be able to evaluate the cost of provision against the shortfall cost, however this relates to making an efficient decision only from the TNSP's point of view rather than the whole market. Where the incentive scheme is weak this may lead to more inefficient outcomes overall.

Efficient investment in new network capacity (section 3.5.6)

Stanwell agree that the optimum level of congestion is not zero, that "*Overinvestment ultimately imposes costs to customers*" and that "*under-investment in the network will prevent generators accessing the wholesale market and lead to a more expensive mix of generation being dispatched to meet demand than would have occurred with more investment.*"

We note that the current system allows TNSP's to augment to allow existing generation more access to the market where such augmentation is cheaper than the alternatives of building a new generator and associated transmission, dispatching high cost generation or incurring unserved energy. This will be retained under the reliability standard which is proposed to operate alongside OFA.

[6] "These impacts should have flow on positive benefits to consumers, to the extent that wholesale prices are passed through into retail electricity costs" first interim report, page 30

What is not clear is the validity of the assumption that if someone is willing to pay for something then it is efficient. Even if such action comes at no cost to consumers, which is unlikely, the loss on investment by the generator would represent inefficiency in the market or economy as a whole.

Efficient investment in new generation capacity (section 3.5.7)

Stanwell note the commissions' concern that there is "*a bias towards the generation and transmission development path that the TNSP predicts, even where a lower cost combination exists*", however since "*Firm access would be cheaper where there is existing spare network capacity than where there is not.*" we consider that firm access procurement may remain transmission led.

Stanwell also consider that the locational signal provided by OFA may not be material when compared to other locational signals such as the availability of fuel, land, water, environmental permits, workforce etc.

The locational signal presented to new entrant generators under OFA will be the *difference* between the Long Run Incremental Cost (LRIC) of several possible connection locations, together with their evaluation of the congestion risk at each of those locations and the proportion of that congestion risk that would be avoided by having firm access. That is, when choosing between two locations the generator has four options instead of two (plus if the generator decides to buy firm access, a choice of how much firm access to buy).
However OFA will not affect the locational decision of generators except in very specific circumstances:

- Assuming that new entrant generators estimate the cost of congestion when deciding on their location, and that the procurement of firm access is expected to mitigate the majority of that congestion risk, then the relative cost of firm access between sites is likely to reflect the relative cost of congestion. Except in circumstances where the pre-congestion decision is very finely balanced, OFA will not affect the generator's decision on where to locate.
- Assuming that new entrant generators estimate the cost of congestion but do not consider firm access to mitigate the majority of this risk, then it is unlikely that the introduction of OFA will result in these generators procuring firm access and hence OFA will not affect their decision on where to locate.
- Assuming that new entrant generators do not estimate the cost of congestion when deciding on their location it is unlikely that the introduction of OFA will result in them procuring Firm Access to mitigate this congestion and hence OFA will not affect their decision on where to locate.

Expressed mathematically:

Let:

$C_{x,NF}$ be the $ value of the non firm generator's congestion at site x

$C_{x,F}$ be the $ value of the (same) firm generator's congestion at site x

$LRIC_x$ be the $ value of Firm Access from site x to the relevant reference node

The four options available to a generator choosing between two possible locations are:

1. Site at location A, don't purchase firm access and accept congestion risk ($0 \leq C_{A,NF}$).
    - Total cost is $C_{A,NF}$
2. Site at location A, purchase firm access (cost $LRIC_A$) and accept the residual congestion risk ($C_{A,F} \leq C_{A,NF}$).
    - Total cost is $C_{A,F} + LRIC_{A.}$

3. Site at location B, don't purchase firm access and accept congestion risk ($0 \leq C_{B,NF}$).
    - Total cost is $C_{B,NF}$
4. Site at location B, purchase firm access (cost $LRIC_B$) and accept the residual congestion risk ($C_{B,F} \leq C_{B,NF}$).
    - Total cost is $C_{B,F} + LRIC_{B.}$

In the unlikely event that all other investment inputs are equal, the generator is likely to select the minimum of the four locational costs: $C_{A,NF}$, $C_{A,F}$+ $LRIC_A$, $C_{B,NF}$, $C_{B,F}$+$LRIC_B$.

There are some significant complications with this approach. It is extremely difficult for a generator to price congestion risk accurately, especially for long term access in an evolving transmission environment and market. It is also extremely difficult to determine the proportion of congestion risk that procuring firm access will avoid.

Assuming that the generator assigns full congestion mitigation to the firm access ($C_{A,F}$=0, $C_{B,F}$=0)the generator's four options become $C_{A,NF}$, $LRIC_A$, $C_{B,NF}$, $LRIC_B$. The generator will likely select the minimum of these four options which is a choice between two estimated numbers ($C_{A,NF}$,$C_{B,NF}$)and two known numbers ($LRIC_A$,$LRIC_B$).

There are likely to be very few circumstances where site A has a higher congestion cost ($C_{A,NF}$) but lower LRIC ($LRIC_A$) than site B, or vice versa. This is because a higher LRIC implies that there is less spare capacity and therefore more congestion forecast at that site prior to augmentation[7].

If site A has a lot of forecast congestion compared to site B then it follows that $C_{A,NF} > C_{B,NF}$ and $LRIC_A > LRIC_B$. This eliminates two of the four options ($C_{A,NF}$, $LRIC_A$) leaving the generator with only two options ($C_{B,NF}$, $LRIC_B$). These remaining two options represent a choice at location B between purchasing firm access or not. In the absence of OFA, the generator is also likely to site at location B since $C_{A,NF} > C_{B,NF.}$

Efficient allocation of risk (section 3.5.8)

Stanwell considers that the proposed model attempts to allocate maximum risk to the generator, regardless of whether the generator is the best placed to determine or manage the risk. We also consider that consumers are left holding significant residual risk, including the risk that the network is ultimately larger under dual planning standards than under a single standard.

Transaction cost (section 3.5.9)

Stanwell agree with the commission "*that where arrangements are complex to administer, difficult to understand, or impose unnecessary risks, they are less likely to achieve their intended ends, or will do so at a higher cost.*"

2.2 Consultation questions

It is important to recognise that in order to evaluate related or dependent design elements considered in the consultation questions it has been necessary to assume proposed changes to the model, this however should in no way be seen as endorsement of these elements or the overall OFA proposals.

[7] The lumpiness of network investment and location specific requirements may dilute this assumption.

2.2.1 Are there any additional categories of impact to those that we have identified?

Stanwell consider that the 9 categories of impact identified in section 3.5 of the first interim report constitute a sound basis for evaluating whether the introduction of OFA would benefit the NEO.

2.2.2 Are there any other impacts than those that we have identified?

No response provided.

2.2.3 Are there any particular scenarios that we should consider in undertaking the assessment?

Stanwell would be interested in the results of scenarios where minimal scheduled and semi-scheduled generation investment is required for an extended period of time. We also consider that it will be important to examine scenarios with very high and very low uptakes of firm access under varying growth scenarios.

2.2.4 Are there any additional issues that we should be investigating?

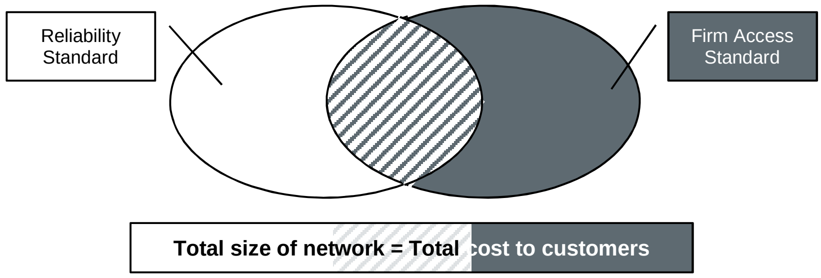
No response provided.

3 Firm Access Standard (1st Interim Report: Chapter 4)

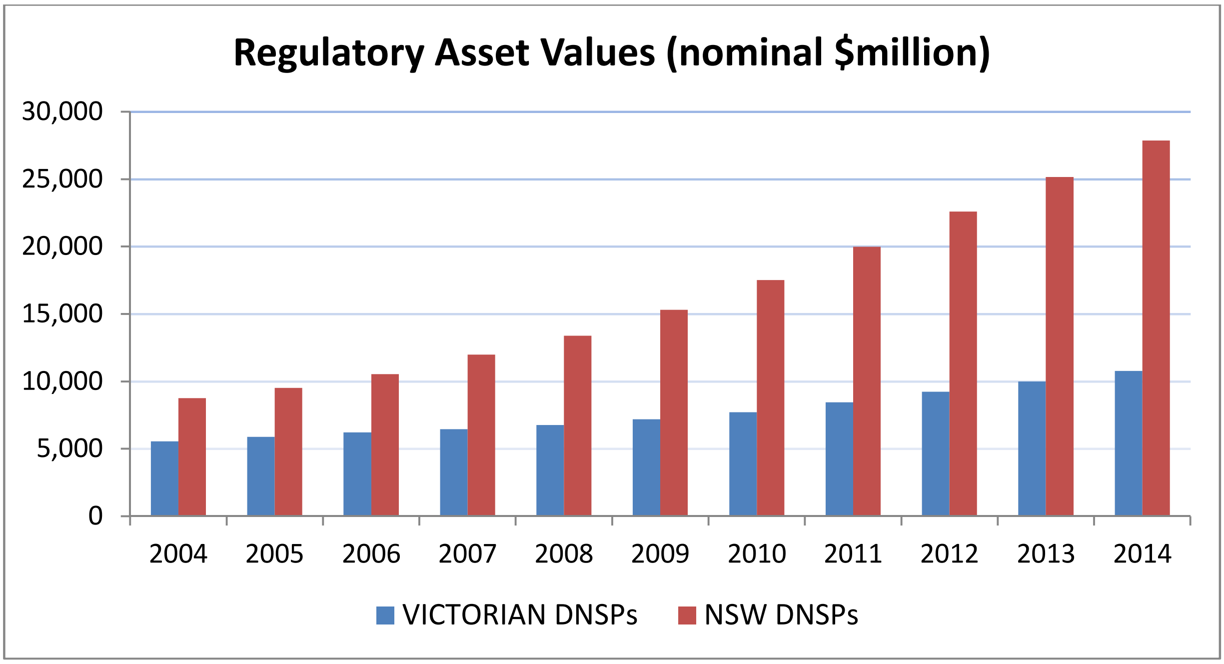
3.1 Stanwell comments

Under OFA, transmission companies must now plan to build their network against two standards - the Firm Access Standard and the Reliability Standard. Generators will pay for network built through the firm access standard and the transmission company will pay for network built through the reliability standard. In both cases the customer ultimately pays for the entire network as both the generator (through the wholesale market) and the transmission company (through network charges) will attempt to pass these costs on to customers.

With two planning standards, the transmission network will likely be larger than it would have been and customers will ultimately pay more. This is illustrated in the Venn diagram below. Although there will be some reliability upgrades that are financed through the firm access standard (the middle striped section), unless the standards perfectly overlap, there is likely to be extra network built entirely for the reliability standard (white section) or the firm access standard (grey section). It is the entire network - whether initially built for the reliability standard or the firm access standard - that is rolled into the TNSP's regulated asset base and used as the basis for calculating its regulated return.



The proposed firm access planning standard will be a deterministic standard rather than a probabilistic standard. Deterministic standards currently apply in NSW and QLD whereas probabilistic standards currently apply in Victoria. Compared to probabilistic standards, deterministic standards have resulted in excessive network spending and high network charges for customers. The following chart shows the much greater proportional increase in the NSW deterministic network compared to the Victorian probabilistic network.



Source: NSW and Victorian electricity distribution pricing determinations

The Productivity Commission Report on Electricity Network Regulation in June 2013 also highlighted the problems with deterministic standards. The Productivity Commission analysed the savings that would accrue to customers should deterministic standards be moved to probabilistic standards and concluded: "*Shifting away from deterministic standards towards a probabilistic cost–benefit framework could produce net present value savings in the realm of $2.2 billion to $3.8 billion over a 30 year period*".[8]

Stanwell understands that the standard must be expressed as a deterministic standard "*expressing the FAPS in a way other than in this manner would mean requiring the TNSP to second-guess a generator's assessment*"[9]. We also note that from the firm generator's perspective, a deterministic standard is likely to be preferable however as noted above, this will be at a cost to customers.

The first interim report attempts to rationalise this as follows:

> "*A generator, in deciding how much firm access to procure, would undertake its own economic assessment of the value of that firmness. The firm access planning standard - by incorporating that procurement decision - would therefore be established as an inherently economic standard.*"[10]

It does not follow that the network will be more efficiently sized. Stanwell would not expect that a network built using deterministic standards and guided by the generator's economic procurement decision is more efficient than a network built using probabilistic standards and the reliability standard.

"*the Rules would set out principles for the development of the firm access planning standard.*"[11] These principles would need to be consistent with the TNSP pricing model or the TNSP would take on price risk. Stanwell is interested to understand how the delay between pricing the firm access and applying the principles in planning is managed. For

[8] Productivity Commission Electricity Network Regulation, June 2013, page 592
[9] AEMC 1st Interim Report, Page 44
[10] AEMC 1st Interim Report, Page 44
[11] AEMC 1st Interim Report, page 44

example, how do the generator and the TNSP reduce the risk of the time delay on factors such as technology change and load change.

The process for setting the firm access standard described on page 44 seems to be very resource intensive on the AER and TNSPs. This should be appropriately costed in the next AEMC report. The AEMC must also ensure that the AER has the capacity to accept the proposed new powers. If the AER is unprepared for additional network planning powers it is likely to be to the detriment of customer network prices.

The "specified conditions" that the firm access planning standard must accommodate are not defined in the 1st Interim Report. Stanwell requests this be defined in the next interim report and not left to the AER to determine (or change) at a later date. Participants need to know this definition in order to assess the proposal. Stanwell is likely to support specified conditions related to local peak network conditions, subject to further definition.

The commissions' statement that "*If the firm access planning standard applied at all times, and not just during specified conditions, this could result in additional augmentations being necessary*"[12] is inconsistent with the next statement "*We note that a generator that was particularly concerned about access outside the specified conditions could decide to purchase a super-firm level of access, which could result in higher levels of access at all times.*"[13] This suggestion would also result in additional unnecessary augmentations and to Stanwell's understanding is incorrect since super-firm access would be capped at the generators capacity and only act to delay access sculpting.

"*Some of the work that we are undertaking includes: examining historical flowgates to determine the extent and impact of constraints that would have bound on a firm access planning standard-compliant network*"[14]. Stanwell requests the results of this study be published including the assumptions and modelling methods. This analysis will help participants evaluate the likely effectiveness of OFA. The analysis could be combined with a study on the likely payments to (or from) generators under the TNSP incentive scheme.

"*considering potential mechanisms that would allow TNSPs to resolve flowgates outside of the specified conditions if their impact is material, for example, allowing augmentations of the network to occur to provide capacity if such investments were favourable to generators*."[15] Stanwell is unsure what situation would induce this investment. It appears as though this upgrade is to occur outside the firm access standard and the reliability standard. It is also unclear as to how this upgrade would pass a revised RIT-T test if the "market benefit" component of the RIT-T is removed.

"*it would be difficult for a single generator to prove that a TNSP failed to plan its network to meet the firm access planning standard, and this failure consequently caused a loss to the generator*" [16]. Stanwell agrees with this statement. It would be difficult to prove that the TNSP had breached the Rules. It is proposed that "*the AER may be the most appropriate body to assess compliance of a TNSP with the firm access planning standard across the entire network.*"[17] Stanwell is concerned that the AER will only be able to do this by relying on information supplied by the TNSP. Again, information asymmetry may mean the TNSP is not adequately monitored and breaches promptly rectified. Both these design elements give little assurance to the firm generator that the purchased access will be delivered. It is also unclear

[12] AEMC 1st Interim Report, page 46
[13] AEMC 1st Interim Report, page 46
[14] AEMC 1st Interim Report, page 46
[15] AEMC 1st Interim Report, page 47
[16] AEMC 1st Interim Report, page 47
[17] AEMC 1st Interim Report, page 47

what the impact would be to the TNSP of a breach of the planning standard if such a breach could be proven.

"*the TNSP may decide to incur access shortfalls where the cost of these shortfalls (to the TNSP) would be less than the cost of the operational remedy.*"[18] The cost to the firm generator does not appear important in this analysis. There appears to be little to prevent the TNSP from choosing to not deliver the firm access planning standard simply because it is more cost effective to absorb the weak penalties under the TNSP incentive scheme. During the TFR the commission was provided with a report from FTI consulting indicating that such behaviour would undermine the whole basis of the OFA proposal[19] and it is unclear to Stanwell why such a proposal remains in the first interim report.

3.2 Consultation questions

3.2.1 What are the implications of the firm access standard applying at all times?

Stanwell supports the firm access standard applying at all times provided the 'specified conditions' are appropriately set. We consider that participants will suffer less unmanageable "shocks" from continuous application of the standard than the previously proposed system normal/abnormal flowgate tagging .

3.2.2 What are the implications of the firm access planning standard being based on specified conditions and how should these specified conditions be defined?

Stanwell are likely to support specified conditions related to local peak network conditions, subject to further definition. See further comment above.

3.2.3 How should the firm access planning standard be enforced?

What has been proposed is a planning standard that has been acknowledged by the AEMC as unenforceable and an incentive scheme that has been acknowledged by the AEMC as 'weak'. In addition, to monitor compliance, the AER is likely to rely on information provided by the TNSP itself. These design elements give little assurance to the firm generator that the purchased access will be delivered.

The mechanism that would provide the best guarantee to the firm generator is a strong TNSP incentive scheme. The design of a strong incentive scheme would include penalties commensurate with the loss suffered by the firm generator rather than a small token of the loss as proposed by the AEMC.

4 TNSP Incentive Scheme (1st Interim Report: Chapter 5)

4.1 Stanwell comments

Developing a TNSP Incentive Scheme

Stanwell supports well designed network incentive schemes that align the interests of TNSPs with those of generators. Under OFA, firm generators pay the TNSP for a specific level of network service. It is therefore appropriate that the OFA TNSP incentive scheme provides adequate compensation to firm generators for reductions in firm capacity. The TNSP incentive scheme proposed by the AEMC does not provide an acceptable level of compensation.

[18] AEMC 1st Interim Report, page 48

[19] FTI *Critical assessment of transmission investment decision-making frameworks in the National Electricity Market,* 4 April 2013, page 28 item 5.6

The 1st Interim report says "A cap was necessary since wholesale spot prices in the NEM can be very high."[20] Stanwell agrees that spot prices can be very high. By purchasing OFA, generators are expecting to receive the regional reference price (whether high or low) for their generation. If firm access is not available during high price periods, firm generators do not receive the high prices despite paying the TNSP for firm access. The TNSP therefore needs a strong incentive to reinstate the firm access. TNSPs are also in the best position to manage the risk of network problems which cause firm access scaling.

"We propose that this new incentive scheme could replace the current market impact component incentive scheme if optional firm access was to be introduced."[21] This could be problematic if low levels of firm access are acquired by generators. In this case, the TNSP may only face an incentive scheme on a small portion of their network. Also, this AEMC statement implies that reliability upgrades will not be subject to the TNSP incentive scheme despite customers paying for network reliability.

"The incentive scheme aims to filter out - as far as possible - the unmanageable risks (for example, the timing of forced outages), leaving a TNSP exposed to manageable risks (for example, the timing of unplanned outages)."[22] This distinction between manageable and unmanageable risks takes the AEMC back to the original firm access design which distinguished between Normal Operating Conditions and Abnormal Operating Conditions. With the revised firm access standard, the TNSP incentive scheme should not be discounted for the probability of 'unmanageable' unplanned outages. The risk of unplanned network outages is a normal part of TNSP operations. Network redundancy is built to account for this, and the firm generator would have paid for this redundancy through their firm access price. For extremely rare catastrophic events, Stanwell supports a limited force majeure clause.

The nested cap design has a number of problems. In order to minimise incentive penalties, a TNSP may purposely conduct as much outage and maintenance work on the same day. This would ensure the maximum penalty that would apply would be the daily cap. Also, if the annual cap has already been reached, a TNSP may bring forward maintenance scheduled for the following year.

The annual cap is proposed to be a total cap per TNSP. This could facilitate an undesirable wealth transfer between generators. A simple example involving 2 generators may be if the annual cap is reached early in the year with payments involving generator A, then generator B does not receive any firm access compensation for firm scaling that occurs later in the year. Some generators may be more exposed to constraints at different times of the year compared to other generators.

Stanwell does not support any caps, only a limited force majeure clause. If caps are to apply, there should be one annual cap per firm generator. In this way every generator could receive a fair allocation of the TNSP penalties.

The AEMC proposes that TNSP incentive scheme parameters are set by the AER and updated either at each TNSP regulatory reset period or annually.[23] The potential for altered TNSP incentive scheme parameters would make evaluating the cost effectiveness of long term firm access very difficult. Because of the uncertainty, generators would apply a large risk discount to firm access prices and this could undermine demand for firm access.

[20] AEMC 1st Interim Report page 53
[21] AEMC 1st Interim Report page 55
[22] AEMC 1st Interim Report page 51
[23] AEMC 1st Interim Report, page 58

T-factor incentive scheme

The design of the T-factor incentive scheme is unpalatable. As an example, a T-factor of 0.9 means a firm generator who has purchased 900MW of firm access will be paying rewards to the TNSP when the TNSP provides greater than 810MW. And yet the generator paid for 900MW! This will be very difficult to explain to investors in generation. The AEMC's solution[24] of the generator requesting the TNSP over size the network is unacceptable and will only add to electricity costs for consumers.

As the TNSP rewards and penalties are based on shortfall costs, if the firm access agreements remain the same over time, then payments from the TNSP incentive scheme should net out to zero over time. This assumes that the T-factor is perfectly efficient. This is highlighted in the example below:

1. A TNSP has a theoretically efficient T-factor of 0.9. A T-factor of 0.9 is set by the AER.
2. The TNSP performs below its efficient level (at say a T-factor of 0.85) and pays penalties
3. At the next reset, the AER then sets the TNSP's T-factor to 0.85. This T-factor is set where where the sum of the penalties and rewards over the previous period are equal to zero.
4. The TNSP then performs again at its theoretically efficient level of 0.9 and receives rewards equal to the penalties paid in (2).
5. The AER then sets the T-factor to be 0.9 and the cycle continues resulting in a zero net TNSP penalty over time.

It appears as though the rewards and penalties are set based on historical uncapped rewards and penalties. Once the TNSP has reached its penalty cap, the TNSP may be incentivised to create further shortfalls in order to receive a lower T-factor at the next reset. Even if further shortfalls were not intentional, generators would only receive penalty payments up to the level of the cap but, at the next reset, the T-factor would be set much lower. With a lower T-factor, generators may receive reduced penalty payments and may be obligated to provide TNSP incentive payments.

When looking back to determine the T-factor, the AER would need to take into account network upgrades completed since the historical period. Otherwise, the TNSP may receive a lower T-factor than necessary.

It appears as though the process for setting the T-factor is likely to be opaque to market participants. In addition, the AER would rely on possibly biased information provided by the TNSP. There will also be a significant technical and information asymmetry between the AER and the TNSP. If the process for determining the T-factor is not transparent, generators will not be able to estimate the T-factor which will likely be selected at the next reset. This would add another risk factor premium to the generator's consideration of firm access.

When setting the T-factor, the AER will consider "the financial position of a benchmark-efficient TNSP"[25]. This does not appear relevant. It would be more relevant (but not advocated by Stanwell) for the AER to consider the financial position of the generators who have purchased firm access and who are relying on receiving firm capacity.

[24] "If T is 0.9 and the generator requires 900MW of access, it may decide to procure 1000MW of agreed access so, after the effect of the incentive scheme, it receives 900MW", AEMC 1st Interim Report, page 69
[25] AEMC 1st Interim Report, Page 58

If caps are to apply and the incentive scheme is to be settled through access settlement, the generator may not be certain of its incentive payments in each actual dispatch period. This is because the cap may have been reached through incentive payments to or from another generator. This uncertainty will be difficult for a generator to factor into dispatch decisions.

Annual Shortfall Target

"Here, the incentive payments and rewards are settled annually, on an ex post basis. This aims to provide generators with more certainty about what they would pay or receive compensation for."[26] Annual payments won't provide more certainty during dispatch or annually. They won't be able to be predicted in advance, but once the year is over, the annual shortfall target scheme will provide more warning of the payment or reward due.

Since the annual shortfall target scheme is settled yearly, it is not necessary to include any caps. If caps are to apply, there should be one annual cap only. Otherwise, a situation may arise where penalties are capped by the nested caps, then later in the year rewards may be earned which further reduce the penalty payable. If the rewards were netted against the uncapped penalties, this would increase the penalty payable by the TNSP and hence increase the TNSP incentive to provide the purchased firm access.

It is unclear how the annual shortfall cost will be calculated if it is not to use a T-factor based calculation. Perhaps reference to the actual shortfall costs experienced by generators in the year could be used as a reference. It is unclear as to how the accuracy of the annual shortfall cost calculation compares to the accuracy of the T-factor calculation. If the annual shortfall cost calculation does not require a T-factor methodology, it appears as though there would be no requirement for the network to be "fully sold" as proposed by the AEMC for the T-factor scheme.

TNSP penalties paid under the annual shortfall cost scheme should be allocated appropriately to the affected generators. Actual shortfall costs seem an appropriate, transparent measure. "An allocation cannot be made solely based on aggregate shortfall costs since, in the event of the TNSP being rewarded, this would mean the generator with the highest shortfall costs would also contribute most to rewarding the TNSP."[27] Perhaps penalties can be allocated based on shortfall costs and the rewards can be allocated pro-rata based on a generator's firm access level. This may mean that generators are paying rewards for extra service they have not received. The alternative is a more complex T-factor style of calculation with its own problems. The most important aspect of the incentive scheme is that affected generators receive adequate, fairly distributed penalty payments.

"Option 2 has a number of additional benefits, including: … it allows time to resolve errors and disputes in the calculation of incentive payments without having to reopen settlements (ie, would minimise transaction costs associated with the regime)."[28] It is alarming that the AEMC considers that there will be disputes in the calculation of incentive payments. As the incentive scheme applies at all times, and payments are based on firm availability and local prices, the calculation of incentive payments should be without dispute.

Impacts of the Incentive Scheme on the TNSP

"a TNSP has a strong incentive to reduce its exposure to penalties by: …. Giving generators advance notice: possibly encouraging (potentially by paying them) them to align their own outage plans or otherwise to change operating or trading plans to reduce congestion costs. (Note that firm generators are not exposed to congestion costs in this example, but non-firm

[26] AEMC 1st Interim Report, Page 61
[27] AEMC 1st Interim Report, Page 62
[28] AEMC 1st Interim Report, Page 63

generators might be)."[29] Unlike STPIS, under the OFA TNSP incentive scheme, incentive payments flow to firm generators. Stanwell is concerned that firm generators may have an incentive to cause congestion in order to receive payments. This may be more likely to occur if generators are given pre-warning of TNSP maintenance and outage activity as suggested by the AEMC.

"This raises the question as to whether anticipated shortfall costs should be included within the RIT-T, allowing a TNSP to deliver flowgate capacity in excess of the target flowgate capacity under firm access planning standard conditions so as to reduce the cost of shortfalls at times that are not the specified conditions for the planning standard."[30] This idea proposes allowing a TNSP to build in excess of the firm access planning standard in order to reduce shortfall costs. This does not seem in customer's best interests, especially as the incentive scheme provides such a 'low powered' incentive to the TNSP. If this were to occur, would the TNSP then have to sell this excess capacity in order to meet the requirements to be fully sold? If so, this could trigger more penalty payments and then more RIT-T endorsed over-development.

"With the assistance of AEMO, we are currently seeking to calculate what payments would have been for TNSPs if the incentive regime had been in place historically. This will inform our future analysis."[31] Stanwell requests adequate details on the input assumptions to this work including the assumed level of firm access, historical periods studied and the treatment of network upgrades. This will enable market participants to confirm that AEMO's assumptions and modelling methods are appropriate. If any modelling results are available, these should be reported along with a detailed analysis of the results. To assist generators in planning and assessing OFA, we also request the analysis specify what specific payments would have flowed to individual generators.

"The latter [shortfall costs] may be difficult to estimate using historical data, since the bidding behaviour of generators in the presence of congestion would often have led to extreme flowgate prices which are unlikely to be repeated under the optional firm access regime."[32] The assumption that optional firm access will reduce disorderly bidding is highly simplistic. Stanwell considers that many of the root causes of "disorderly bidding" remain unaffected by OFA. For example under OFA, a generator that is dispatched below its access level during congestion remains incentivised to bid in a manner that will set the local price as low as possible because the firm access revenue will exceed the opportunity cost of forgone dispatch.

Similarly, there is an implicit assumption that the procurement of firm access will reflect economically efficient dispatch however this is unlikely. During congestion under OFA, low cost generators with no access, partial access or scaled firm access may be incentivised to bid in a way to reduce output in favour of high cost generators who have firm access. This has a detrimental affect on economic efficiency.

"If congestion prices double, say, but performance is maintained, rewards would double but so would penalties, meaning that they still net out to zero."[33] If congestion prices double, then the TNSP incentive scheme caps also need to double in order to achieve the stated zero net result. Otherwise, depending on the order in which the penalties and rewards occur, the result could be skewed and the AEMC statement incorrect.

[29] AEMC 1st Interim Report, Page 65
[30] AEMC 1st Interim Report, Page 66
[31] AEMC 1st Interim Report, Page 67
[32] AEMC 1st Interim Report, Page 68
[33] AEMC 1st Interim Report, Page 68

“We note that a generator should be certain about the level of access (ie, 100 per cent) it would receive during peak conditions (ie, where the FAPS applies).”[34] The generator has no reason to be certain about the level of access during the specific conditions applicable to the FAPS. Firstly, as acknowledged by the AEMC, the FAPS is practically unenforceable[35]. Secondly, the TNSP incentive scheme is weak - the TNSP can deliver less than the firm access paid for by the generator without penalty.

4.2 Consultation questions

4.2.1 Is it appropriate that the proposed TNSP incentive scheme specifies both rewards and penalties?

A TNSP incentive scheme where the TNSP receives rewards for providing less than the firm access generators have purchased is unacceptable. As an example, a T-factor of 0.9 means a firm generator who has purchased 900MW of firm access will be paying rewards to the TNSP when the TNSP provides greater than 810MW. And yet the generator paid for 900MW! This will be very difficult to explain to investors in generation. The AEMC’s solution[36] of generators requesting the TNSP to over size the network is unacceptable and will only add to electricity costs. See further analysis above.

4.2.2 Would generators value firm access differently when there is a surplus compared to when there is a shortfall?

Generators are more likely to be concerned about the level of the caps. The proposed TNSP incentive scheme is low powered and will not provide adequate compensation to firm generators. In addition, the Firm Access Planning Standard is practically unenforceable[37]. Generators will evaluate firm access based on these critical deficiencies rather than if the TNSP incentive scheme is currently in surplus or shortfall in a particular year. See further analysis above.

4.2.3 How should the nested caps and collars be structured, for example, is it necessary to defined these caps all the way down to trading intervals?

The nested cap design has a number of problems. In order to minimise incentive penalties, a TNSP may purposely conduct as much outage and maintenance work on the same day. This would ensure the maximum penalty that would apply would be the daily cap. Also, if the annual cap has already been reached, a TNSP may bring forward maintenance scheduled for the following year.

The annual cap is proposed to be a total cap per TNSP. This could facilitate an undesirable wealth transfer between generators. A simple example involving 2 generators may be if the annual cap is reached early in the year with payments involving generator A, then generator B does not receive any firm access compensation for firm scaling that occurs later in the year. Some generators may be more exposed to constraints at different times of the year compared to other generators.

Stanwell does not support any caps, only a limited force majeure clause for extremely rare catastrophic events. If caps are to apply, there should be one annual cap per firm generator. In this way every generator could receive a fair allocation of the TNSP penalties. See further analysis above.

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[34] AEMC 1st Interim Report, Page 69
[35] AEMC 1st Interim Report, Page 47
[36] “If T is 0.9 and the generator requires 900MW of access, it may decide to procure 1000MW of agreed access so, after the effect of the incentive scheme, it receives 900MW”, AEMC 1st Interim Report, page 69
[37] AEMC 1st Interim Report, Page 47

4.2.4 Is the T-factor (Option 1) structure of the annual target (Option 2) structure preferred?

The annual target structure is preferred as it is less complex however no caps are necessary. If caps are to apply, there should be one annual cap only. Otherwise, a situation may arise where penalties are capped by the nested caps, then later in the year rewards may be earned which further reduce the penalty payable. If the rewards were netted against the uncapped penalties, this would increase the penalty payable by the TNSP and hence increase the TNSP incentive to provide the purchased firm access. See further analysis above.

4.2.5 Does the incentive scheme provide certainty (or not) for generators in terms of both the product and also the payments that they would be expected to make?

No neither, the TNSP incentive scheme is weak and provides little certainty that the purchased firm access will be available when required. Generators should not have to make payments under the incentive scheme as they have already paid for the firm access. See further analysis above.

5 Long-term inter-regional access (1st Interim Report: Chapter 6)

5.1 Stanwell comments

Stanwell consider that the arrangements for inter-regional access, or Firm Interconnector Rights (FIRs), represent an area of enormous complexity with significant further work required.

Stanwell acknowledges the consistency with the current SRA arrangements provided by the commissions' proposals that FIRs be for directional interconnectors[38] and that auction proceeds in excess of LRIC would be apportioned to the importing TNSP to offset TUOS[39]. We also acknowledge the consistency between intra-regional access and FIRs provided by the commitments to using LRIC pricing as the auction reserve and a "take it or leave it" approach where bids are below this LRIC[40]. Beyond these points we consider that the discussion of Inter-regional firm access raises a number of areas of significant concern.

It is unclear why the commission confirms that "*The firm access planning standard definition means that firm access is essentially an annual product*"[41] yet retain the position that long term access will be auctioned in quarterly blocks[42]. If shaping of access purchases were allowed, Stanwell would expect that Long Term FIRs would be required to have their maximum volume coincident with the period being used for evaluating planned access provision under FAPS. This could cause significant complexity if the planning assumptions were to change over time. For example NSW has seen peak demand[43] occur in winter for 4 of the last 8 financial years. It is unclear whether this would be modelled as a summer or winter peaking node and what effect that would have on Queensland and Victorian modelling.

Stanwell is assuming that restrictions "*…placed on how long the inter-regional access sold at the auction would be available for…*" would be directly related to the commissioning and end of asset lives used in determining the LRIC. It is unclear what other considerations would be required for this element.

The consideration of different kinds of transmission limitations is raised in relation to interconnector upgrades but applies equally to some intra-regional transmission paths. Stanwell strongly agree that all constraint types must be considered when determining LRIC pricing and likely access provision, not just thermal limitations. The commission note that "*The challenge in setting long run incremental cost for stability "elements" is to choose the appropriate expansion projects to model*", however Stanwell considers that this complexity would apply to all LRIC modelling, regardless of the constraint type.

We consider that the first interim paper barely scratches the surface of what a complex, labour intensive task LRIC determination for FIR auctions is likely to be[44]. For each directional interconnector the (probably two) relevant TNSPs will need to coordinate their evaluations of what network changes are technically feasible, in what timeframe, at what cost and with what expected result on inter-regional access, including with reference to the impact of other constraints on the flowpath between regions. As an example, the recent

[38] AEMC 1st Interim Report, Page 76
[39] AEMC 1st Interim Report, Page 80
[40] AEMC 1st Interim Report, Page 77
[41] AEMC 1st Interim Report, Page 79
[42] AEMC 1st Interim Report, Page 73
[43] Demand here refers to AEMO published half hourly data, being the sum of scheduled and semi-scheduled units.
[44] "There would also be a lot of effort involved in setting up a full auction, such as the TNSP preparing long run incremental cost calculations and market participants preparing bids." AEMC 1st Interim Report, Page 79-80

work performed by Powerlink and Transgrid on possible QNI upgrades identified a number of upgrade options with differing timing, cost and effect, many of which included multiple augmentation tasks to different parts of the network(s).[45] This report was the culmination of an almost 2 year co-operative process which built on previous work in relation to this flowpath[46]. This example also indicates the complexity of managing the multiple constraints which exist on all elements[47]. It also indicates that it is unlikely that TNSPs would be able to simply apply a "building block" approach to pricing increasing levels of access.

In addition to the engineering related complexity discussed above, Stanwell is concerned that the proposal to "*factor in any additional benefits associated with providing future intra-regional firm access*" risks making the pricing of FIR favourable when compared to access pricing for intra-regional access. It is unclear what additional consideration should be extended to inter-regional access pricing.

Stanwell notes that the commissions' first interim report includes a number of areas which are acknowledged to rely on the ultimate auction design, and specifically the concern about whether the use of LRIC will enable TNSPs to cover the average cost of augmentation[48]. We consider that it would be consistent with OFA intent that augmentation would be pursued if buyers have shown a willingness to pay the associated cost, even if there are more "optimum" or profitable solutions for lower levels of augmentation[49]. This is consistent with the view expressed in the first interim report that the auction structure should "…maximise the likelihood that an interconnector would be expanded"[50]. The logical extension of this would be that the maximum possible expansion should occur where cleared bids meet or exceed total cost, however an alternative model could be used where after the first expansion becomes "bankable" further expansions are priced relative to that point (rather than relative to no expansion). This would likely reduce the size of expansions, risking inefficiencies, but also avoid possible significant over-build where a capacity expansion being paid for by a third party would decrease the desire of a participant to fund further augmentation[51].

5.2 Consultation questions

5.2.1 Are stakeholders interested in purchasing inter-regional access?

Stanwell considers that OFA must allow for the issuance of inter-regional access (or Firm Interconnector Rights) for both long and short terms in order to have a chance of allowing

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[45] QNI upgrade study PADR located at http://www.powerlink.com.au/Network/Network_Planning_and_Development/Documents/QNI_Upgrade_Project_Assessment_Draft_Report_March_2014.aspx

[46] PSCR process initiated June 2012, PADR published March 2014. Previous processes on the same flowpath have been occurring since 2004 with the last process completed in 2008.

[47] QNI upgrade study PADR – section 2.2.1

[48] AEMC 1st Interim Report, Page 79

[49] Stanwell is assuming a "pay as bid" auction design. This design seems more in keeping with the FIR ethos of having participants indicate what they are willing to pay and accepting that higher number if is exceeds the LRIC than a constant clearing price model.

[50] AEMC 1st Interim Report, Page 73

[51] If augmentation occurs the expected price separation between regions would be expected to decrease and this may be sufficient mitigation for a previous bidder. Supported by NERA economic consulting *Review of Financial Transmission Rights and Comparison with Proposed OFA Model* 12 March 2013, page 8 "*…new investment in transmission could eliminate existing congestion and largely nullify the value of FTRs and ARRs in the near term*"

the market to function, however we support the view that significant investment in new long term access is unlikely[52].

We have significant questions about how the LRIC of FIRs will be developed given that they will include notional access across the entire flowpath between two nodes. Specifically, what conditions will be being modelled in the sending region? Under FAPS it is expected that flows in a region will generally be towards the local node[53], meaning that the "sending" component of interregional access will likely be unconstrained, however where price separation between regions occurs[54] it is likely that flows on the network will not reflect this condition. It is unclear which TNSP will pay the shortfall charges and to what extent if inter-regional access is degraded due to constraints in the sending region.

Additionally, upgrades to increase access in one direction are likely to lead to increases in access in the opposite direction in many cases. How this "backhaul" access is treated will depend on the auction design.

5.2.2 Is the proposed process for the issuance of long-term inter-regional access appropriate?

Where long term Firm Interconnector Rights are to be issued, Stanwell support the aggregation of bids in order to expose the maximum market value of such rights. We also support the market operator, as a non-TNSP third party running the auctions with pricing input from the TNSPs.

Stanwell do not agree that long term FIRs should be sold on a quarterly basis as this is inconsistent with the proposed FAPS which is deterministic based on a nominated peak flow condition.

[52] NERA Economic consulting, *Review of Financial Transmission Rights and Comparison with the proposed OFA model*, 12 March 2013, page 9. ""…FTRs have not been found to incentivise new merchant transmission investment in the US"

[53] Subject to resolution of the Tasmanian situation where the primary load centres are distant from the node.

[54] It is unclear whether price separation needs to occur for FIRs to have value. The first interim report indicates that price separation is necessary on p71 "…would entitle them to the price difference between two regions" and p72, however where interconnectors have a term in a constraint on an intra-regional flowgate the value of that constraint may not be the difference in prices between the regions.

6 Short-term firm access (1st Interim Report: Chapter 7)

6.1 Stanwell comments

Stanwell consider the issuance of short term firm access to be subject to most of the same complexities as long term access discussed elsewhere in this submission while introducing some of its own. We note that it remains only partially defined, as was the case in the TFR.

If short term access is to be issued we agree that a single point of issuance for both inter and intra regional access is likely to be appropriate. We also agree that given the complexity of the task, a centralised process such as an auction is likely to be required. While the issuance of access would remain bewilderingly complex (especially FIRs), this approach would remove the problem of competing issuance timeframes for inter- and intra-regional access.

As noted in relation to the issuance of long term FIRs, it is unclear what conditions would be considered in relation to the exporting region at “peak” conditions in the importing region.

The proposal that FIR bids be aggregated[55] before clearing appears superfluous for short term auctions and may risk decreasing the ability for participants to purchase FIRs[56]. Individual participants bidding with a source of one RRN and a destination of a neighbouring RRN with an associated volume and price should be able to be cleared by the auction. Aggregation and proportional allocation would only be required for the purposes of access settlement.

Unlike for long term access, Stanwell consider that short term access could be auctioned in quarterly blocks similar to SRAs, so long as the volume sold in each quarter complies to the proposed FAPS.

6.2 Consultation questions

6.2.1 Is it appropriate that the short term access tenure is up to the transmission expansion time (estimated at 3 years)?

We support the proposal to define a generic “short term horizon” within which to issue only short term access, and after which only long term access can be issued. We do however consider that the lead time for investments may be quite long given the need to complete a (possibly extended) RIT-T and actually perform augmentation work. It may be more workable to simply define the short term horizon as being the same as the current SRA forward sale period (3 years).

However the proposed issuance of short term access raises the question of how FAPS is to operate within the short term horizon. If, for example, forecasts change[57] and FAPS is no longer met but augmentation is not possible, what happens? This question feeds into the definition of what short term access can be auctioned – if short term access is sold 3 years ahead and subsequent events mean that the FAPS cannot be met, what happens to short and long term access holders, and the TNSP?

[55] AEMC 1st Interim Report, Page 89

[56] Depending on auction design and how aggregation occurred, a high priced bid for a relatively small volume may be made uncompetitive against intra-regional access requests by being combined with a lower priced bid for significant volume.

[57] Inputs such as demand, embedded and non scheduled generation participation etc can change materially between APRs.

6.2.2 Is it appropriate that the short-term access product is treated identically to long-term firm access?

We remain unconvinced that short term access should have the same level of firmness as long term access given the relative commitment exhibited by buyers of these products – long term buyers have committed to an LRIC based payment under all circumstances while short term buyers are targeting specific circumstances in a much more certain network environment.

The commission have stated their support for equal treatment on the basis that any dilution of long term access relating to short term access is not "undue" in that it "*does not cause the quality of the service to fall below the level specified by the firm access planning standard*"[58]. Stanwell dispute the relevance of this as the OFA terms of reference specifically refer to the operational standard rather than the proposed planning standard as the Firm Access Standard and the commission acknowledges that the sale of short term access will increase TNSP exposure to the incentive scheme[59] (which applies only to the operational standard).

The alternative proposal – to treat short term access as mezzanine rights – carries its own significant complexities, particularly relating to secondary trading. For the rest of this response Stanwell will assume that short term access will be issued as equivalent to long term access despite our reservations.

Stanwell propose that some component of the sales revenue should be available to compensate holders of long term firm access in the event that their access is scaled back as a result of the issuance of this short term access.

We consider that short term access must be subject to the same TNSP incentive arrangements as long term access. We are however disappointed to see that the commission has moved away from the TFR proposal for a strong incentive scheme to relying on the very weak scheme proposed in the first interim report. We note that the original design risked creating short term access that was more beneficial to the buyer than long term access due to the requirement that TNSPs pay 100% of any settlement shortfalls, however feel that the weakening of the short term access incentives to match the weakened long term access incentives is a move in the wrong direction.

6.2.3 Is an auction with no reserve price the most efficient means of allocating short-term firm access based on existing spare capacity?

The first interim report notes that there may be costs – and therefore reserve prices – associated with short term access arising from TNSP operational decisions. Stanwell also consider that existing access holders who wish to offer volume into an auction are likely to have a non-zero value assigned to that access and hence would require the ability to define a reserve price.

For access arising from TNSP operational decisions, a cost based reserve price appears appropriate, while for sales by existing access holders, a seller defined reserve price should be available. For access arising from the existing network, a notional reserve price of zero appears reasonable however this may be influenced by whether there is recognition of the impact of additional access on long term access holders. If such recognition exists, it may be rational for a TNSP to indicate likely shortfall costs and use this as a reserve price.

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[58] AEMC 1st Interim Report, Page 85

[59] "…the TNSP may choose to withhold some network capacity from the auction since this would reduce its exposure to the incentive scheme". AEMC 1st Interim Report, Page 89

The existence of multiple tranches of access with differing reserve price means that the auction design needs to be defined more comprehensively than has been done to date. For example, is the aim of the auction to clear the maximum value of bids possible or clear bids with the maximum premium to the relevant reserve prices?

Stanwell would expect that existing capacity would be cleared prior to access arising from TNSP operational decisions as it is costless – this would include sales from existing holders even where there is a non-zero reserve price. There are also questions such as whether offers are "fill or kill" or can be partially cleared, and whether mutually exclusive bids can be provided (for example a generator may wish to buy either but not both of intra- and inter-regional access).

6.2.4 Does the allocation of sales revenue from the auction provide the right incentives and obligations on TNSPs?

Stanwell consider that the allocation of sales revenues from short term auctions may depend on the source of the access volume but should be targeted at providing incentives and compensation to the appropriate parties. This section does not consider auction fees, although we acknowledge that such fees should be recovered.

For access sold by an existing access holder, 100% of revenue should be allocated to that seller. As total sold access remains the same as prior to the auction, there would be no dilution of existing access[60].

For access sold by the TNSP arising from existing network capacity, revenue should be allocated to compensate existing access holders (as required) then primarily to reducing TUOS in line with the current SRA process. While Stanwell consider that notionally all the non-compensation revenue should flow to TUOS reductions, we acknowledge the commissions concern regarding incentives for TNSPs not to issue such access. Accordingly, a small component of this revenue may need to be allocated to TNSPs.

For access sold by the TNSP arising from "additional" operational activities, the same compensation for existing access holders should occur followed by recovery of costs to the TNSP. Any remaining revenue should be shared between the TNSP – in order to incentivise it's provision - and TUOS reductions - in order to ensure consumers benefit where possible.

Under this approach:

- consumers are protected and may benefit, relative to no access being sold;
- Existing firm access holders are somewhat protected from dilution of their access;
- TNSPs face increasing incentives for the offer of access; and
- existing access holders are incentivised to provide access into auctions – reducing the need for additional expenditure required by TNSP operational decisions.

6.2.5 Should the TNSP be obligated, or heavily incentivised, to release short-term access?

Stanwell consider that the answer to this question is likely to be heavily influenced by other as-yet undefined aspects of short term access and auction design.

We agree with the commission that there is a possibly significant governance issue regarding the information asymmetry between the TNSPs and other participants – particularly the regulator – in terms of defining what existing access should be available and differentiating this from access provided from operational decisions.

[60] Unless there is an impact from individual plant capacity.

Under the proposed t-factor incentive scheme there appears to be a marginal benefit to the AER from obligating TNSPs to provide short term access from the existing network, however such benefit may be offset by the complexity of determining TNSP compliance with such additional obligations.

As indicated above, Stanwell consider that the sale of short term access is likely to increase the instance and extent of access shortfalls which will be of detriment to existing access holders, and this needs to be addressed before TNSP obligations or significant incentives are implemented.

7 Access Settlement parameters (1st Interim Report: Chapter 8)

7.1 Stanwell comments

Stanwell believes that consideration of access settlement parameters must include the AEMO work stream on implementing access settlement. In general we consider that this aspect of OFA is critical to defining and understanding the model and believe that it has not received sufficient focus to date.

We believe that the AEMO work on access settlement has raised a number of significant issues which are not intended to be addressed by the AEMC's first interim report, particularly in relation to loss factors, 5/30 settlement and constraint violations. While we will restrict our consideration of these elements in accordance with the guidance in the first interim report we note that these appear to be fundamental concerns which require resolution.

- The consideration of loss factors in particular creates significant complexity. Stanwell understands that one of the fundamental features of OFA is the separation of access and dispatch, and note that loss factors are explicitly tied to dispatch modelling.
- We are unclear if, or how, loss factors would be applied to access volumes, or indeed to points of congestion that are electrically distant from both the generator(s) and the node.
- If congestion is occurring at a common point it may not matter that participants have individual loss factors, although Stanwell consider that more work needs to be done in this area.
- It is also unclear whether the assumed flow in the firm access pricing model (which we understand will be largely access based) will correlate to annual loss factor calculations.

We also note that it appears that TNSP compensation for under-provision of firm access will not form part of access settlements. We encourage the commission to ensure that generators are not exposed to large cashflow timing variations between NEM settlements and TNSP payments as this could cause financial distress if hedge contracts have been sold on the expectation that access is provided.

7.2 Consultation questions

7.2.1 How to reconcile the metered generation used for settlement and dispatch?

Stanwell would expect access settlements to operate on the same basis as is currently used in the market – dispatch meters are used to define the "intent" of the market operator while revenue meters are used to determine all settlement values.

7.2.2 How should auxiliary load be treated?

Stanwell have some concern regarding the proposal to allocate "*each generating station's auxiliary load across associated dispatchable units*" in order to implement the concept of a revenue meter id (RMID). Depending on the implementation, the generator may be allocated load on a unit which is offline despite the station auxiliaries being more than covered by the generation at other units at that site (using different revenue meters and hence RMIDs). We would encourage the relevant entity (currently assumed to be the system operator) to ensure that "net negatives" are kept to a minimum in this logical mapping, even if this requires some element of dynamic (but predictable) allocation.

For new auxiliary load we support the proposal to require load and generation to be electrically close, although we consider the other three criteria may exclude valid auxiliary loads in some circumstances (for example joint ventures). We consider that in relation to network management, operational and commercial association in particular may not be meaningful if the load and generator are electrically close. Additionally there is likely to be a net auxiliary draw in the period prior to a unit being synchronised which does not sit well with the definition of temporal association.

We note some apparent confusion in regards to the treatment of auxiliary load within section 8.4 of the first interim report. Page 97 indicates "*the load pays the local price rather than the regional reference price*" whereas page 98 indicates "*In trading intervals where the net output of a RMID is negative, the generator would pay the regional reference price as if it were load*". Stanwell understand that when the generator is online, an auxiliary load effectively pays the local price[61] and note that it would be inconsistent to charge that auxiliary load the RRP when the unit is offline unless access usage can be a negative value. We are unaware whether there has been any consideration given to negative access usage values.

7.2.3 Is the grandfathering of existing metering arrangements appropriate and cost effective?

Stanwell support the minimisation of regulatory risk on existing projects in the face of significant market design changes where possible. Accordingly we support the proposal to grandfather the current metering and auxiliary load arrangements for loads which are electrically close to the associated generator.
We have some concern regarding the cost to the "around 5 generating stations" who would not receive grandfathering arrangements due to their load not being electrically close, and believe more information regarding the impact of this would be appropriate before committing to a position.

7.2.4 How should different generation types be treated?

Stanwell hold significant concerns that OFA will incentivise new entrants to pursue non scheduled registration where possible in order to gain preferential access at no cost. While this is also currently an incentive it is mitigated by scheduled and semi scheduled generators also receiving access at no cost, albeit at a less preferential level. If scheduled and semi scheduled generators were to be required to choose between free low priority access and costly mid priority access, it would become more inappropriate that non scheduled generators receive free high priority access. We note that increases in non scheduled generation will create planning and forecasting issues for the market as well as having impacts on market transparency.
In relation to embedded generators which are also discussed in the first interim report, Stanwell note that some embedded generators are likely to have multiple electrical connections to the transmission system through the distribution network. Evaluating what access can and should be related to which connection point is likely to be complex and subjective with potentially significant cost differences.

7.2.5 How generation capacity should be defined?

Stanwell considers that capacity should be defined in a readily accessible and consistent manner. While the proposed solution provides this to some extent, we consider that it may be significantly simpler to simply use the rated nameplate capacity rather than historical output. This would remove the market distortion caused by each generating unit having to run at maximum output at least once every two years in order to retain their capacity-based

[61] Since it will decrease the dispatched generation being paid RRP but increase incoming access payments receiving (RRP-Local price), or decrease outgoing access payments in the same manner.

access allocation[62], especially since in the procurement of firm access there is no requirement relating to dispatch. It would also decrease the amount of data that must be processed regularly to ensure the capacity information is up to date.

We also note that the proposal to use historical output as measured by the RMID (being on a "sent out" basis) would create a capacity definition that is inconsistent with nameplate capacity (which is "as generated") in many instances. We do not see any benefit in this inconsistency.

Stanwell understands that there is a proposal under development to alter the definition of capacity after the first interim report and will consider that proposal separately.

[62] Or notify the market operator that its circumstances have changed within a year.

8 Transitional Access (1st Interim Report: Chapter 9)

8.1 Stanwell comments

Stanwell believe that consideration of transitional access arrangements is premature while the OFA model is in a significant state of flux. Accordingly our response to this aspect of the first interim report will primarily focus on the concepts behind transitional access rather than the specific mechanics of the work performed to date.

Stanwell supports the four objectives for the transition to OFA reiterated at the start of section 9.2.1 of the first interim report. We do however disagree with the AEMC's apparent interpretation of objective 2 "*to encourage and permit generators – existing and new – to acquire and hold the levels of firm access that they would chose to pay for*". Stanwell does not consider that this design objective requires or even implies that existing generators must pay for access in order for that access to reflect the level of firm access that they would choose to pay for were they in a position to evaluate OFA at the time of making their investment.

Similarly in section 9.3.2 the commission state:

> "*Therefore, in deciding on the transitional access sculpting profile that best serves the long-term interests of consumers, an inherent trade-off needs to be made between:*
>
> - *managing the commercial and financial impacts of optional firm access on existing investors, along with providing a learning period; and*
> - *encouraging generators to purchase the level of firm access that they value.*"

Stanwell believe that the second dot point includes a false equivalence and should more accurately read "discouraging generators from holding transitional access that they don't value". This false equivalence extends to the subsequent paragraph of the first interim report which states *"…in the medium to long term it is desirable that all generators - existing and new - pay for firm access if they wish to hold it*" which Stanwell also disagrees with.

Stanwell also has concern around commission statements which imply that regulatory burdens are more acceptable depending on when they occur or what lead time is provided[63]. Any cost impost, or reduced access to peak pricing resulting from not incurring that cost, will be reflected in asset values and refinancing costs regardless of whether they are scheduled to occur in the short or long term. In the NEM there is a convenient recent experience of generators attempting to refinance in the lead-up to the introduction of the Carbon Tax, where GDF-Suez for example elected to fund Hazelwood power station from parent entity funds rather than external financing, despite being the recipient of government compensation for carbon in the short term. Had third party debt funding been available on terms considered reasonable to the borrower then it is generally considered likely that GDFSuez would have maintained the traditional funding structure[64].

Stanwell acknowledges the commissions' work in relation to stakeholder concerns regarding barriers to entry for new plant, and agree that as new entrant plant would have the ability to decide whether to enter the market in the knowledge of firm access, the price paid for

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[63] AEMC 1st Interim Report Section 9.2.1 paragraph 3, section 9.3.2 paragraph 10 and associated dot points

[64] "Hazelwood bailed out by parent GDF Suez" http://www.businessspectator.com.au/news/2012/6/26/climate/hazelwood-bailed-out-parent-gdf-suez We note that the Loy Yang B was refinanced at a similar time utilising third party debt while InterGen refinanced Millmerran and Callide C in Queensland using a combination of equity injections and third party debt.

access by its competitors is immaterial. We further consider that if such a barrier to entry were to exist, then by implication it is clear that insufficient allocation of transitional access for existing participants would mean that the introduction of OFA is unfairly onerous to those businesses.

Finally, before turning to the specific questions from the first interim report, Stanwell wishes to highlight the bias contained in statements such as:

> "*such generators would therefore receive a potentially substantial benefit for no direct payment*"[65]; and
>
> "*It is important that the level of transitional access granted to existing generators be reasonable. Where access must be purchased consumers would benefit since revenue from the sales would offset the charges passed through to consumers. Where access is granted for free consumers miss out on these benefits. We should not set out to unnecessarily create windfall gains for generators that are paid for by consumers.*"

The former appears to be in comparison to a situation where OFA is introduced with no transitional access but with other generators having purchased firm access, rather than the current arrangements which formed the basis of the relevant investment decisions.

The latter reflects a totally unacceptable approach to market development, where it is considered appropriate to cause financial distress to existing generation participants who have invested under a certain set of circumstances, and in relation to investments that have already been made by the TNSP on the basis of providing reliable access to customers, in order to provide a benefit to consumers which will be at best a fraction of the impost to the affected generator[66].

8.2 Consultation questions

8.2.1 Is the approach for the initial allocation of transitional access appropriate?

Stanwell broadly support the theory that the initial allocation of transitional access should reflect, to the extent possible, the implicit level of access that existing generators have under current arrangements based on how they use the network. This approach will be critical to minimising the perception of sovereign/regulatory risk inherent in investments in Australia and particularly the NEM. This aspect is well encapsulated in section 9.3.1 of the first interim report:

> "*Indeed, the investment that was made by an existing generator is likely to have been based on expectations of transfer capability from a particular location, for which the generator would not pay a charge.*"

This approach however risks enshrining current economic inefficiency inherent in the current model, despite OFA being predicated at least partly on reducing or removing such inefficiency. Any attempt to remove this efficiency would require preferential treatment to certain technologies, participants or registration types which Stanwell believe would be inappropriate.

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[65] AEMC 1st Interim Report, Page 80

[66] Assuming the affected generator is able to pass a portion of the cost of OFA into the wholesale market, the impact on customers may be net positive or negative depending on market forces. For example if a generator is able to recover 50% of the cost of firm access, the total cost to the market of that recovery is likely to far exceed 50% of the access cost due to the gross pool nature of the NEM and the relatively fragmented nature of generation ownership. Stanwell note that the SRMC bidding view of the market promoted in much of the economic analysis does not reflect this as the access cost is likely to be treated as a fixed rather than variable cost and not included in SRMC calculations.

Stanwell also support the proposal to ensure that the initial allocation of transitional access allows TNSPs to remain compliant with the Firm Access Standard.

8.2.2 Should transitional processes protect existing investments from significant financial detriment but also not unduly dilute or delay the benefits of optional firm access?

Yes.

The AEMC have previously noted that the introduction of OFA "*would represent a fundamental change to the market, and would not be without risk*"[67] and it is appropriate that sunk investments are protected from such actions[68].

With regard to the dilution or delay of the benefits of optional firm access, Stanwell consider that transitional access is unlikely to do this unless very poorly designed. Accordingly it is worth considering the proposed benefits of OFA[69] and evaluating how, or indeed whether, these benefits are affected by transitional access.

Proposed benefit 1: provide a more commercial framework for the planning of transmission network… As transitional access is only proposed to apply to the extent that it is capable of being provided by the existing network, Stanwell do not consider that it will impact this objective unless transitional access causes network expenditure which would not otherwise occur. This is expanded on in response 8.2.3 and 8.2.5 below.

Proposed benefit 2: provide locational signals… for the siting of new generators. Stanwell believe that this confirms that locational signals are not a valid consideration for existing generators (as their location is fixed). Accordingly, any price signals arising from the reduction or absence of transitional access would not serve to promote this proposed benefit of OFA.

Proposed benefit 3: provide incentives for the TNSPs to manage congestion…to minimise the impacts on market participants. Stanwell consider that this benefit will only arise in the presence of firm access agreements but will not be affected by whether these agreements relate to transitional or additional firm access. If transitional access were decreased through arbitrary sculpting and not re-purchased immediately by generators then the incentive of TNSPs would be weakened.

Proposed benefit 4: provide a basis to encourage inter-regional trade and identify the value of upgrading interconnector capability. Stanwell remain unconvinced that the introduction of OFA will materially improve the ability of participants to trade inter-regionally or provide incentive to upgrade interconnector capability[70]. To the extent that forced scaling is supposed to release access which could be used to back FIRs, this would require access to be present on all flowgates in the inter-regional path at the same time, and for the generators having their access sculpted to have not procured this released access back from the TNSP prior to the FIR auction. We note again the commissions' recognition regarding the complexity of setting up a long term inter regional access auction.

[67] TFR Exec summary page 1.
[68] AEMC first interim report page 109 first paragraph.
[69] These benefits are outlined in section 2.2.1 of the first interim report
[70] "…FTRs have not been found to incentivize new merchant transmission investment in the US." NERA economic consulting *Review of Financial Transmission Rights and Comparison with the Proposed OFA model*, 12 March 2013, page 9

Proposed benefit 5: facilitate economic bids from generators, by removing incentives in the current market for non cost-reflective bidding behaviour under constrained conditions. While Stanwell disagree with the premise that OFA will decrease incentives for "disorderly bidding", if such a benefit were to occur we consider it to be unlikely to be affected by whether a generator holds transitional or purchased firm access.
In summary, of the 5 proposed benefits of OFA only one shows any scope to benefit from early reductions in transitional access and the practicality of achieving this appears very limited.

8.2.3 Is Option 3 the best method for sculpting?

Stanwell considers this question to be inappropriately biased as we do not consider that the X,Y,Z,K approach to sculpting is the only, or most appropriate, model for sculpting of transitional access if such sculpting is required. While we acknowledge that transitional access sculpting was part of the terms of reference, we do not consider that this requires the implementation of the X,Y,Z,K model. In particular we note that this model was "optional" in table 10.1 of the TFR but that the AEMC does not appear to have investigated alternative approaches.

Stanwell agree with the commission that granting transitional access to generators in perpetuity would not improve the benefits of the introduction of OFA. Despite such an arrangement being likely to benefit Stanwell, we consider that it is likely to result in poor policy. We also support the proposal to set the end of transitional access ("Z") to reflect the expected end of each generator's economic life where the introduction of OFA could not have been reasonably foreseen at the time the investment decision was made.

Stanwell support the commissions' decision not to progress with consideration of a scheme which would degrade existing generator's transitional access to provide free access to new entrant plant, as this would be inconsistent with the logic of OFA.

Stanwell do not support the commissions' implicit distinction between a generators actions in respect of transitional or purchased firm access, expressed through statements such as "*If existing generators are granted access for free they may hold access that they do not value*". The assumption that a generator would hold or attempt to sell access based on whether or not that access comes with an existing fixed charge is illogical. Rather, generators would logically hold or sell access based on whether the market was willing to pay a price sufficient to compensate the generator for the lack of that access.

Stanwell also question the validity of the assumption that sculpting transitional access is desirable as this is "*recognising that generators implicit access is always at risk of being degraded over time (for example by the location of a new generator)*". The desire to reduce access degradation (and congestion) due to new entrant locational decisions is one of the key drivers of OFA and has been reflected in the discussions since the Review of Energy Market Frameworks in light of Climate Change[71]. It is unclear why the AEMC are attempting to enshrine the negative aspects of the model that they are proposing to move away from.

With respect to the three options presented in the first interim report, Stanwell considers that option 1 is likely to breach transition objective 4 – "*to prevent abrupt changes in aggregate levels of agreed access…*". Transition objective 4 would also be breached for option 2 if K

[71] http://www.aemc.gov.au/getattachment/a50a3acf-b34c-478a-b47f-95fb0b6af00e/Summary-of-Discussions-Industry-Forum-Sydney-17-Au.aspx "Participants generally agreed that proponents of new or increased generation capacity should face a long run marginal cost (LRMC) signal of the impact of their investment on the network access of other generators"

were small (since Y=0), for option 3 if both Y and K are small, or if Z=X+Y for any significant number of sites (which is likely to only apply to option 3) unless K is very small.

As indicated above, Stanwell consider that the proposed X,Y,Z,K model is flawed regardless of which of the three options is preferred by the commission, and propose that alternative models be considered once the majority of the OFA model is settled, if a decision is made to proceed. One such alternative is presented below in 8.2.5.

8.2.4 Should X be related to the time period after which TNSP augmentation of the network is likely? What time period is this likely to be?

As indicated above, Stanwell do not support the use of the X,Y,Z,K model for access sculpting.

Stanwell also do not understand the reference to "the time period after which TNSP augmentation of the network is likely" which is contained in the question. As X is proposed to be identical for all generators such augmentation must be a reference to any augmentation in the network, and Stanwell understands that all current TNSP plans and revenue proposals contain at least some element of augmentation work. Under these conditions, TNSP augmentation of some part of the network is always likely, i.e. X=0 which is clearly inappropriate.

If this model were to be adopted, Stanwell would consider that X should be set to at least account for the issues highlighted in section 9.4 of the first interim report, namely:

- a learning period;
- a subsequent period long enough for existing generators to procure new long term firm access (including any RIT-T and construction timeframes applicable to the network required for such a request);
- a period to allow for the forward contracting behaviour of at least the majority of generators; and
- a period sufficient to allow regulatory arrangements relating to TNSP revenue and incentives to be adjusted.

8.2.5 Is it feasible to calculate individual K and Z value for each power station and if so, what factors should be taken into account when calculating these. If it is not feasible to calculate individual K and Z values, what approach should be taken to calculate these values?

As indicated above, Stanwell do not support the use of the X,Y,Z,K model for access sculpting, however we believe that calculating Z for individual power stations would be achievable and beneficial to the determination of transitional access.

The calculation of K, whether for an individual station or all participants, is likely to be more complex and contentious. Calculating K for each station would also create complexity for the proposed "initial auction", although Stanwell believe that participants receiving varying levels of initial transitional access will create similar issues – that is how is block 3 defined?

Stanwell believes that alternative structures would be likely to provide more robust benefits. For example:

- set initial transitional allocations to reflect the implicit access that existing generators have under the current arrangements (similar to what is proposed);
- set and end date for transitional access based on the expected economic life of the power station (similar to Z);

- potentially have an end of life sculpting period reflecting expected lower capacity factor operation leading in to retirement (similar to Y and K, with K=0 and Y = say 10 years to minimise volume shock. This Y would be measured backwards from Z rather than forward from X as in the AEMC proposed model);
- have the TNSP consider whether assets underpinning transitional access would be replaced, renewed or altered were such access not present:

  - o If the asset would be retired or down sized then the transitional access amount could be reduced accordingly to prevent customers paying for otherwise unnecessary network spend.
  - o If the affected generator(s) valued the access they would be able to buy firm access through normal procurement methods. The TNSP may also be able to provide for concurrent requests in this circumstance (since multiple generators are likely to be affected).
  - o Any reductions under this process would require a lead time equivalent to the proposed "X" discussed in the previous section.

- For additional access requests, transitional access would be included in both the baseline and alternative scenarios:

  - o The new access would be modelled in the awareness of transitional access. Accordingly, where purchased and transitional access were both present for the TNSP replacement assessment (above), transitional access would need to be considered and the purchased access would sit "above" the transitional access.
  - o This would be necessary to ensure that a purchased access agreement which assumed augmentation (or replacement) did not later result in a reduction in transitional access by that augmentation (or replacement) not occurring.

9 Staged implementation (1st Interim Report: Chapter 10)

9.1 Stanwell comments

Stanwell welcomes the commissions' recognition "*that the need for an implementation approach depends on a positive assessment of the impacts of optional firm access*"[72] as we consider that some elements of the project – particularly some of the consultant work – has proceeded as if a positive assessment had already been completed.

We generally consider that the commission has identified the implementation issues and their relevant impacts. As noted, the most constraining element appears to be TNSP revenue regulation timeframes.

With this in mind, were OFA found to have a positive assessment, Stanwell consider that options 1 and 3 are likely to be preferable, with any geographical staging minimised to align with these TNSP regulatory periods. We consider the option 2 proposal to introduce access settlements, FAPS and FAOS/incentives at different times is likely to create an extremely ineffective solution.

As Stanwell does not consider that a positive assessment of the impacts of optional firm access is likely, and that if it were to occur the commission has broadly identified the relevant issues, we do not consider there to be any relevant response to be made to the specific consultation questions.

9.2 Consultation questions

9.2.1 Are there any additional implementation issues?

No response provided.

9.2.2 Are there restrictions set out on implementation issues consistent with stakeholder views?

No response provided.

9.2.3 Are there any other options for implementation?

No response provided.

9.2.4 What are the benefits and costs associated with the different implementation options?

No response provided.

[72] AEMC 1st Interim Report, Page 121

10 Reliability Access (1st Interim Report: Appendix A)

10.1 Stanwell comments

Stanwell believe that appendix A to the first Interim report highlights many of the issues with the proposed OFA model and development process.

First and foremost, we believe that the proposed inclusion of a "contingent auction" in relation to reliability access is in direct contradiction of the terms of reference for this project. Specifically, table 10.1 of the TFR states:

> "*RIT-T assessments no longer include benefits and costs that accrue to generators*".

While the commission states that the proposed design "…*is consistent with the core and recommended elements of table 10.1*" we believe this statement is shown to be false on a number of occasions in the document, most notably 2 paragraphs earlier.

> "*The issue we have considered is the question of: since reliability access provides benefits to non-firm generators, should these benefits be incorporated into the RIT-T, and if so, how?*"

Stanwell considers that the statements of the commission are in direct opposition and cannot reasonably be considered to be consistent.

While not reflected in the first interim report, Stanwell is aware of the background material provided to the working group, and based on this information we believe that this concept has been developed due to the commission and/or their consultant interpreting the core requirement regarding "benefits and costs that accrue to generators" as applying only to the estimation of dispatch cost by a TNSP during a RIT-T process. Stanwell fundamentally disagrees with this interpretation.

We note that the terms of reference allow for the commission to "*confirm or modify the design of critical elements of the OFA model as a result of testing*". Accordingly, the proposed design being inconsistent with the core elements of table 10.1 is not reason in and of itself not to proceed, however we consider that the commissions claim to consistency is inappropriate. We also consider that the proposed change is not "as a result of testing" but rather as a result of ideology.

Should the proposed design be acknowledged to be inconsistent with the core elements of table 10.1 but be pursued anyway, Stanwell consider that the proposed design is likely to be unworkably complex and result in a more expensive network, which ultimately comes at additional expense to consumers.

Before addressing the cost and complexity of this aspect of OFA, we wish to clarify two points relating to the proposed reliability access model:

- generators will not be bidding on specific network augmentation options as implied by the paper unless they are new entrants facing a locational decision which correlates to the augmentation options presented. Rather, generators will be bidding for a certain volume of access from point A (the station) to point B (the node) starting at one point in time and running to a later point in time.

- there is also an implicit assumption that interested generators would have recently investigated the cost of procuring firm access and found it prohibitive[73]. Given the amount of network maintenance, replacements and augmentations that occur constantly in the NEM, it is unlikely that each or even most relevant generators would have up to date LRIC requests.

The complexity primarily arises in relation to the RIT-T process and the requirement to calculate pre- and post- augmentation LRICs for all generators affected by a proposed upgrade:

- "All generators affected by the proposed upgrade" would include both existing and potential new entrant generators whether they had a current or recent firm access request in place or not. Additionally, generators who do not have a term in the relevant constraint formula could also be affected due to the change in network flows following an augmentation[74].
- The calculation of LRICs would require knowledge about the desired volume (if any) of access for each participant as well as what would be forecast to be provided by the reliability upgrade in isolation which may be different for each generator[75].
- The valuation of "additional cost of providing firm access" could potentially include a large augmentation than required for the reliability upgrade.
- The complexity would become more significant in light of the possibility highlighted by the interim report that where multiple firm access requests could be fulfilled which lower TUOS the combination of augmentations would be expected to be fulfilled. We note that the priced network solutions for each bid may overlap meaning that they cannot simply be added together.

The proposal to extend the RIT-T process to include a process of indicative then binding contingent auction bids is also likely to create significant complexity:

- Expressions of interest would notionally be based on information contained in the PSCR, however as indicated above, generators are unlikely to bid in relation to a specific proposed augmentation path, but rather for generic access. Also as indicated above, the same augmentation would be likely to deliver different benefits to each generator, so it is uncertain what information would be taken from the PSCR to inform generator bids. More likely, in conjunction with the PSCR the TNSP would have to develop information packs for all generators who could possibly be expected to participate in the access auction, indicating at a minimum the volume and timing of access arising from the proposed augmentations (plus any complementary augmentations required to provide this access).
- The commission have recognised that at the expression of interest stage, despite it being "*unlikely that a generators bid could be considered binding*", "*the results of this expression of interest could potentially lead the TNSP to consider other upgrade options*" which would further increase the workload associated with the RIT-T. We note that no options could be reasonably discarded based on non binding bids or their absence.
- After the passage of some time, the TNSP would then issue a PADR which "*would contain draft cost-benefit assessments, including a generator's (unbinding) willingness to pay…*". Stanwell considers that this publication of commercially sensitive information would likely discourage generators from providing a genuinely reflective bid at the expression of interest stage, if they provide a bid at all. This may negate the benefit of

[73] "it should be noted that the generator's willingness to pay for reliability access would be less than the price of expansion as determined by LRIC." AEMC 1st Interim Report, Page 103

[74] This would likely be primarily related to proposed new generation and existing plant that has a constraint term which is considered immaterial but which may become material post augmentation.

[75] Generator participation factors pre and post augmentation would need to be reasonably calculated in order to determine the MW impact for each generator location.

conducting the EOI. We note that it is likely that between the PSCR and the PADR many of the assumptions may have changed, for example timing of augmentation or incorporation of the effects of other augmentations, changes to demand forecasts, the generation fleet or market rules.

- Regardless, the auction round would then occur, creating binding bids on the generators. We expect that all bids would need to be considered binding while the final cost-benefit assessment was completed, meaning that generators would be unable to confidently pursue other access agreements during that period. We would also expect that the conditions described in the PADR would be binding on the TNSP for the PACR – especially the timing and access volume available as a result of the proposed augmentation. We are unaware whether this would be considered acceptable to TNSPs, but suspect it will be met with resistance.

The additional cost to consumers has been obscured by the commissions' reluctance to include the possibility that a generator procuring firm access will attempt to recover this (potentially large) cost through the wholesale market. We acknowledge that this may have been done for simplicity given the subjective nature of modelling spot market impacts of one specific change, however taking the example in Table A.2 of the interim report:

- The proposed model delivers $280 million in network investment compared to $100 million which would be likely to occur under the current system, or $150 million which would occur under the current system if there were sufficient modelled third party (generator) benefits.
- The interim report claims that the process delivers a direct saving to consumers as the net cost of the larger expansion is only $60 million once firm access payments are taken off the capital expenditure, however this figure is in fact only the net TUOS cost, not the net cost.
- The generator which is incurring a $220 million expense is extremely unlikely to be able or willing to absorb such an impost and would attempt to pass as much of this cost into the market as possible.
- If the generator were successful in passing just 41/220ths of this cost into the market consumers would pay more than under the $100 million expansion.
- Additionally, by passing some of it's cost into the market the generator may increase the wholesale price[76] which would also be received by other generators, further increasing total cost to consumers.

We believe that the simplest examination of this example would consider that a $280 million network investment would be unlikely to provide lower cost – as opposed to a lower TUOS charge - to users than a $100 or $150 million investment. As indicated above, attempting to add further rigour into the analysis leads quickly into complex assumptions which should decrease confidence in the outcomes, but appears unlikely to change them.

Stanwell considers that if implemented, this proposal would further decrease the genuine optionality of "Optional Firm Access", supported by the commissions' statement that:

> "*the theoretical ideal of the optional firm access model is that access should only be provided in response to firm generators' willingness to pay*"[77].

[76] Acknowledging that there's a hugely subjective discussion regarding whether congestion would have occurred with and without firm access and what impact that would have on wholesale price.
[77] AEMC 1st Interim Report, Page 134

This theoretical ideal would exclude non-firm access, but would still not provide fixed access or full compensation for contracted access not being provided. We consider it an interesting view of the market given the commissions' recognition that "*new entry should occur where investors have a reasonable expectation over time of making a risk adjusted rate of return sufficient to support an investment case*"[78] and that such an expectation would be predicated on sufficient demand for their service being present.

10.2 Consultation questions

10.2.1 Should the reliability mechanism be a "core" or "recommended" element of OFA?

Stanwell considers that the proposed model is in direct contradiction to one of the core elements contained in table 10.1. Should this be considered acceptable, we would be guided by the commissions' characterisation of the model as "*We consider that this proposal lies outside the core model of optional firm access. That is, optional firm access can be implemented without the proposal outlined in this appendix*".

Whether the proposal would be considered "recommended" or "optional" is more open to debate. The categorisation will likely depend on the overall view regarding the desired extent of changes to the RIT-T, noting that the required changes relating to this element are significantly complex, but that significant changes to RIT-T will be occurring regardless.

10.2.2 Would generators purchase reliability access?

Stanwell consider it likely that if this model were incorporated into OFA it would further reduce the optionality of Optional Firm Access and that generators would therefore be likely to participate in contingent auctions, subject to the concerns regarding disclosure of commercially sensitive information discussed above.

Whether more participation is considered preferable may largely depend on whether you have read ROAM Consulting's modelling report relating to the TFR, particularly section 6.4.

10.2.3 What commitments should be associated with bids?

Stanwell agree that if a contingent auction process were to occur in response to the PADR then the material aspects of those bids and the PADR must be binding in order to minimise the possibility of an uneconomic solution being progressed. Penalties for each party should be commensurate with the effect of the breach.

For generators we consider that the price, volume, start date, end date and location contained in the bid would need to be binding on all bids until the PACR is completed and the firm access agreement is completed. The penalty for generator withdrawal would primarily relate to the cost difference between the solution which incorporated their bid and the alternative solution that is developed in the absence of that bid, plus an administrative charge relating to the additional work to determine the alternative.

For TNSPs we consider that the same factors must be binding – that is volume, start date, end date and location of the firm access request. While the TNSP is expected to have provided pre- and post-contingent pricing as part of the process it is unclear whether these need to be held firm[79]. It is unclear what penalties would apply in the event that the TNSP varied one of the "binding" parameters however Stanwell consider that at a minimum all bids

[78] AEMC 1st Interim Report, Page 111

[79] However Stanwell consider that is the pre-augmentation cost were to change such that it is less than the generator bid price then firm access should automatically be assigned at LRIC.

would become non firm if this occurred. It is also unclear whether varying the basis of the auction would require a new round of auctions to be conducted and what mechanism could be used to allow for this.

10.2.4 How could the current RIT-T process be modified to take this process into account?

As Stanwell does not support the proposal we have not dedicated resources to detailed analysis of the required RIT-T changes.

11 Initial transitional access allocation (1st Interim Report: Appendix B)

11.1 Stanwell comments

As indicated in response to section 8, Stanwell largely consider that the details of transitional access are more appropriately considered once the OFA model is no longer in a significant state of flux.

We consider that any methodology will contain subjectivity and tradeoffs which will be contentious, and agree that the establishment of some design principles at an early stage of OFA development may reduce the level of contention:

- Stanwell supports the intention that the initial allocation of transitional access attempts to minimise sudden and significant changes in the market or participant's margins as a result of regulatory change. We agree that this can be approximated by allocating existing network capacity among existing generators in a way that replicates the implicit access level that they currently receive.
- We believe the 4 stage process outlined by the commission is broadly appropriate, although we strongly disagree with their proposed approach to step 3 (sculpting) as detailed in earlier responses.
- We support the 4 transitional objectives described by the commission and repeated in section 9.2.1 of the first interim report. We do not support the 5th proposed transitional objective proposed by HoustonKemp Consulting which we believe is counter to the first 4.
- We believe consideration needs to be given to the effect of non-scheduled and intermittent generation and load on the peak scenario being used for initial allocation of transitional access and planning as well as operational delivery.
- We support the use of recent or reasonably model-able near future network capability as appropriate for determining initial allocation of transitional access.
- We consider that the currently proposed approach to regional demand is likely to be an over-simplification that will lead to distortions, and encourage the commission (and AEMO) to consider the use of less arbitrary assumptions, as discussed in the following responses.

In relation to the specific modelling performed to date, Stanwell acknowledges that future application of the current proposed methodology will appropriately produce different results due to changes to network configurations and generation fleet.

We support the 2 stage approach to allocate transitional access to generators then interconnectors, despite recognising that clamping the interconnectors may have the effect of reducing reflectivity of results. At this stage Stanwell has no proposed alternative which would improve reflectivity at a reasonable level of complexity and so continuation of the current assumption seems appropriate.

We accept, with some reservation, the proposed approach of having all units offer 10 equal tranches of volume at equivalent prices in order to avoid undue penalty of specific units under the modelled binding constraint(s). In particular we note that some units would not be able to structure their offers in such a manner, and this is expanded on in 11.2.1 below.

Stanwell also notes the commissions concerns regarding the requirement for some conservatism in setting the initial transitional access allocation to allow the TNSP not to be in breach of its planning requirement, however we consider that this is less of a risk than is implied:

- As noted in the commission's first interim report, evaluation and enforcement of the FAPS compliance is likely to be extremely difficult. In the situation where a TNSP has "planned" to provide the contracted level of access on a reasonable basis and that situation does not occur, it would result in an operational derating of firm/transitional access but not a breach of the planning standard.
- Accordingly, as long as the assumptions used are "reasonable" (and acknowledging the issues related to the use of subjective terminology), the only impact of allocating higher levels of TA than are actually delivered would be on the incentive scheme related to the FAOS. As this is proposed to be low powered, with TNSPs only paying a portion of shortfall charges and subject to caps, we do not consider this to be a significant risk to the TNSP[80].
- We do however consider that there may be issues relating to flowgate support generators where there is no network support agreement in place.
- In any event, there appears to be no consequence for the TNSP not meeting its planning standard.

Stanwell also note the concern of the commission regarding possible manipulation of offers in the lead up to the calculation of transitional access in order to gain a higher share of this access than would otherwise be warranted[81]. While Stanwell generally consider than most generators will be made available at times of market stress, we accept the commissions' concerns about manipulation of the transitional access allocation methodology. For scheduled units, where participant strategy is an integral part of dispatch decisions, we believe that the currently proposed methodology based on capacity provides a reasonable approximation of the possible access requirements at peak times. As discussed in the next section, for intermittent units we believe there may be improvements to the methodology that would account for their particular circumstances.

11.2 Consultation questions

11.2.1 Is the proposed method to calculate transitional access appropriate?

Stanwell supports the intention that the initial allocation of transitional access attempts to minimise sudden and significant changes in the market or participant's margins as a result of regulatory change. We agree that this can be approximated by allocating existing network capacity among existing generators in a way that replicates the implicit access level that they currently receive.

We believe the 4 stage process outlined by the commission is broadly appropriate, although we strongly disagree with their proposed approach to step 3 (sculpting) as detailed in earlier responses. In relation to steps 1 and 2 which are the focus on this section, Stanwell believes that there are some rational and relatively non controversial alterations to the approach taken to date which would be likely to improve the rigor of the process without significantly increasing its complexity.

Stanwell agree that step 1 should calculate "*the level of firm access they would need to have unfettered access to the regional reference node – …calculated based on historical generation patterns*" but do not consider that the approach used is fully reflective of this intent. Particularly in respect of intermittent generation, Stanwell believe that some analysis of their historical generation patterns relative to the peak periods such as those used for planning would be appropriate. This is because intermittent units generate "as available"

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[80] For generators receiving firm access as a result of this planning there is a question of whether lower, firmer access levels are preferable to higher, less firm access levels, however Stanwell has not been able to form a specific opinion on this topic.
[81] AEMC 1st Interim Report, Page 154

and are typically only restricted by constraints or lack of fuel (assuming that the peak period does not have negative pricing in which case they would likely not want access). In instances where such generators consistently show low correlation between output and the planning condition (other than due to constraints), Stanwell believes that allocating them transitional access on a pro-rata basis with scheduled technologies would introduce undue inefficiencies and value transfers.

In relation to step 2, Stanwell urges that caution be used when attempting to "*…aim to maximise the allocation of access…*". While maximising the notional volume of access appears desirable, such action may unduly compromise individual plant based on their participation factor in the specific constraint(s) which are limiting access in the modelling. While some level of variation in transitional access allocation is likely to be broadly efficient and equitable, large variations may be more economically efficient but significantly less equitable. Such a situation would risk breaching the transitional objectives.

Stanwell also believe that the process by which a regional load is "grown" to allow the system to balance would also benefit from some additional rigor, while noting the issues described by the commission. This is further discussed in response to 11.2.2 below.
Finally, Stanwell note that the proposed method has little regard to the effect of non-scheduled generation which is likely to become an increasingly important consideration in coming years.

11.2.2 Are there any variations in the input assumptions that could be considered?

The proposed methodology uses recent demand and network information when determining transitional access allocations. While we broadly support this approach, particularly in reference to network capability, we note the risk that the reference period used may not be consistent with a planning scenario. For example an extremely hot/cool/wet/dry summer may significantly distort the reference demand. While this risk is somewhat diluted by the "growing" of demand to balance supply, the proposed approach of simply adding load at the RRN means that the resulting access allocations are likely to be affected by the base demand data. Stanwell would encourage the commission and its' modellers (likely to be AEMO) to consider multiple years of historical demand when deciding on the reference data to attempt to minimise such distortions.

Additionally, as noted above, Stanwell has concerns that the simple addition of load at the RRN may produce non-reflective network flows which will distort access allocations. Particularly with the recent publication of connection point data, we believe there is scope for consideration of this load growth being applied in a more informed manner, based for example on historical peaks, variability or percentage contribution to regional demand. While the results would almost certainly retain an element of subjectivity, they are likely to be more reflective than the currently proposed method, producing initial allocations which are more reflective of current implicit access.

11.2.3 What is the materiality of any issues with the proposed approach?

It is hard to comment on the materiality of these issues given that the results are acknowledged to vary considerably for changes in some inputs – for example the constraint affecting South West Queensland plant prior to April 2014 but not after this time.

With the limited information available at this stage, Stanwell would consider that the method of determining the base demand then growing it to allow system balance is likely to be the most material issue in the modelling. In the example modelling conducted to date this has been highlighted as a significant issue for both Tasmania (load centre ≠ regional node) and NSW (low base demand year requires significant additional load at the node, affecting which constraint binds) while being less of an issue for other states.

The treatment of intermittent and non scheduled generation (and load) will also be important.

11.2.4 What are some alternative methodologies?

Stanwell has no specific comment in relation to this question that has not been discussed in previous responses.