Major Energy Users Inc.

AEMC Transmission Frameworks Review

COMMENTS ON AEMC SECOND INTERIM REPORT

Submission by

The Major Energy Users Inc

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Executive Summary

The Major Energy Users Inc (MEU) welcomes and supports the recommendations of the AEMC's second interim report, which provide a significant step forward from the current approach. The MEU considers that the AEMC approach to the issues identified is sound and has teased out most of the essential elements that need to be considered.

Notwithstanding the above, the MEU considers that there are a number of aspects that the AEMC should consider or reconsider:

1. The MEU concern that RIT-T should include the transfer of wealth from consumers to generators caused by congestion and generators using constraints to increase prices

2. The viability of non-firm access

3. The conclusion that there is no evidence that there has been a lack of investment in inter-regional connection

4. Alignment of TNSP regulatory reviews

The MEU provides arguments addressing each of these issues.

In summary, however, the MEU supports:

1. Optional form access (OFA) as providing significant benefits to the NEM, and the MEU offers some minor improvements for consideration

2. The suite of measures proposed to improve transmission by planning

3. Common approaches to NEM wide transmission pricing with AEMO tasked to undertake a national role in pricing

4. Improvements in the process of negotiating connection arrangements

1. Introduction

1.1 An overview

The Major Energy Users Inc (MEU) welcomes the opportunity to provide its comments on the AEMC's Second Interim Report relating to the Transmission Frameworks Review.

In previous responses to the Transmission Frameworks Review, the MEU highlighted that the electricity market is weighed down by a myriad of problems resulting from:

- Increasing concentration of the energy supply industry, especially in retail
- Re-aggregation of generation and retail
- Emergence of vertically integrated energy supply businesses that have dominance in both generation and retail
- Increased barriers to new entrants in generation and retail
- Escalating network costs and hence electricity prices
- Extensive interventions by both Federal and State Governments that have created major distortions and resulted in raising costs and inefficiencies

To this list should be added concerns with the Limited Merits Review process although the MEU notes that the SCER appointed Expert Panel has identified that the MEU concerns in this regard are well founded and the Expert Panel is developing solutions.

The MEU has also previously noted that issues surrounding pricing of transmission services should be addressed as part of the Transmission Frameworks Review and the MEU is pleased to see that a key aspect of the Second Interim Report addresses this concern.

Overall, the Second Interim Report picks up and addresses several important aspects of the provision of transmission services. The MEU congratulates the AEMC on the depth of analysis and thought that has gone into the concepts detailed in the report.

The MEU considers that the recommendations made in the report provide a significant step forward to the current approach. Despite this general support for the proposals as detailed, there are some aspects and considerations that the MEU considers are necessary to ensure the best outcome is achieved for all users of the transmission system.

1.2 A Specific Issue the MEU has with the Second Interim Report

The MEU is concerned with an apparent inconsistency in the report.

In the generator access part of the report, there is a view stated that combined cost of generation and transmission need to be assessed to ensure the lowest overall cost is achieved, because this will deliver the most efficient outcome. This observation is inherent in a number of comments in the report such as:

> "The Commission is seeking to identify the set of arrangements that is most likely to promote efficient investment and operational outcomes for generation and transmission over the long term" (page 2)
>
> Those that supported change [to the current arrangements] … did so on the basis that … coordination between transmission and generation investment is not currently optimised (page 6)
>
> "[There is a] lack of clear and cost-reflective locational signals for generators, such that their locational decisions do not take into account the resulting transmission costs (page 20)
>
> "These [pricing] signals should promote more efficient use of the existing network and, by exposing generators to the long term transmission costs associated with their locational decision, help to co-optimise generation and transmission investment (page 32)

Having recognised that the most efficient outcome will be achieved by optimising investment in both generation and transmission (and hence the cost of these services to the market) the report then discusses the MEU concerns that the RIT-T should include the transfer of wealth from consumers to generators caused by congestion and generators using constraints to increase prices. The report comments:

> "Previous reviews have concluded that including wealth transfers away from generators in assessing the benefits of an investment is likely to negatively impact investment in generation, thereby damaging the long term interests of consumers. No evidence has been provided to suggest there is a case for revisiting this conclusion" (page 59)

The MEU points out that by co-optimising investments of generation and transmission, the report provides its own evidence that the two elements (generation and transmission) need to be considered together. Optimising the costs of generation and transmission to achieve the lowest overall (and therefore efficient) cost requires that the RIT-T needs to combine all of the costs and benefits from the various options for establishing the preferred option from the RIT-T.

There can be no doubt that a wealth transfer to generators is a cost to consumers. The NEO requires all assessments to be made in the long term interests of consumers and a benefit to consumers is the avoidance of a wealth transfer from consumers to generators. If this can be avoided by an investment in the transmission network to reduce congestion, then this should be included in any assessment of the benefits of that investment.

The report comments that including the wealth transfer into the RIT-T would be:

> "…likely to negatively impact investment in generation, thereby damaging the long term interests of consumers" (page 59)

The MEU does not see that this observation is consistent with the principle underpinning the OFA proposal for relieving congestion. In the OFA model, a generator can provide funding to a TNSP for it to obtain an exclusive benefit (that of firm access) to ensure that it is able to export its product at the price that it considers is appropriate. In contrast, the report then considers that consumers are not permitted to invest in additional transmission assets to relieve congestion that causes them quantifiable transfers of wealth to generators.

In practice, as the second interim report notes, the OFA would permit a generator or retailer to provide funding to increase the capacity of an interconnector so that it can better compete with other generators. The report posits that the generator or retailer:

> "…would be entitled to the price difference between two regions on its access amount." (page 40)

In contrast, the report denies this same ability to consumers to fund an augmentation that would also increase competition between generators, reduce the costs to consumers of congestion and reduce (even eliminate) unnecessary wealth transfers.

The MEU sees that the decision to exclude the benefits of augmentation to include the wealth transfers is quite inconsistent despite the second interim report commenting that there is no need to revise the RIT-T to include the market impacts of wealth transfers between generators and consumers resulting from congestion (page 59). The MEU considers there is a case to revisit the issue that it has raised.

2. Access and Congestion

The second interim report provides a view that there are basically two viable options for providing generator access.

The first is essentially a status quo option (non-firm access) and the second is an optional firm access (OFA) option. The report cites that the OFA option is a combination of options 2 and 4 detailed in the first interim report.

In its response to the First Interim Report the MEU expressed a preference for an alternative option but did express a view that of the five options proposed in the First Interim Report, it considered that option 4 was the next best, especially if features of its preferred option were used to enhance option 4.

In its response to the First Interim Report, the MEU proposed a number of commercial realities that needed to be recognised as part of the assessment of the way forward

In its preferred option, the MEU proposed there were some key aspects that need to be addressed in any model, viz:

1. The best approach for consumers (the focus of the NEO) is one which minimises the cost of delivered power. To ensure this is the case, the cost of generation and transmission need to be considered jointly.
2. Once built, a generation asset is a “sunk cost” and that decisions were made on its location based on conditions that applied at that time. Unfettered access at a later stage to an incipient generator which creates congestion for the existing (and incipient) generator is a risk which adds costs.
3. Requiring new entrant generators to bear the entire cost of relieving any congestion would be a barrier. To overcome this, all generators that benefit from congestion relief must contribute to any augmentation. If they contribute then they must have some benefit (eg preference in dispatch)
4. There should be no compulsion on a generator to contribute to congestion relief, but if it does not then it should not be dispatched.
5. Consideration has to be given a new entrant generator for the increased costs that it might incur if it located where it would not cause congestion compared to the lower costs it might incur if it located where congestion was likely. To locate most efficiently for the market requires that the lower cost option is identified when the costs of both generation and transmission are combined
6. If there is no congestion caused, then no costs are incurred.

The MEU assessment of the options is based on the above criteria.

2.2 Non-firm access option

This option essentially maintains the status quo. It suffers from the problems that generator locational signals are very weak and as a result provides the essential ingredients to increase the likelihood of increased periods of congestion resulting in higher costs for consumers.

When compared to the six key MEU criteria listed in section 2.1, the non-firm access option fails on a number of counts. The following table highlights in red where each criterion fails.

Criterion	Issue	MEU observation
1	Reflects combination of generation and transmission costs	**No**
2	Unfettered access for new generator	**Yes**, only limited by the risk that the new entrant might not be able to export all of its capacity all of the time
3	All generators contribute to congestion relief	**No**
4	Compulsion to contribute to congestion relief	No
5	Costs to locate to avoid congestion recognised	**No**
6	No cost if no congestion	Yes

It is quite clear that retaining the status quo approach will not address the issues of current (or increased) congestion as the generator location signals are too weak to get a change, and there is little pressure to ensure that the new generator will not locate to minimise congestion.

The MEU does not see how this option can enhance achievement of the NEO

2.3 Optional firm access (OFA) option

The OFA option provides considerably more incentive to locate where congestion will be minimised and provides a mechanism how additional augmentation might be funded to minimise congestion. The MEU appreciates the effort that the AEMC has gone into in providing as much detail as it has to provide a good understanding of the OFA option.

Using the same MEU criteria for assessment as for the non-firm access model, the following table highlights in red where the model fails some of the criteria.

Criterion	Issue	MEU observation
1	Reflects combination of generation and transmission costs	**No,** although the cost of firm access does, in part, reflect the combination of both elements. See note 1 below
2	Unfettered access for new generator	No, as it highlights that when assessing the costs associated with its location, it will incur some costs if it wants certainty of dispatch
3	All generators contribute to congestion relief	**No**, only those generators seeking firm access incur the costs. Other (non-firm) generators take the risk that they will not be notionally dispatched, See note 2
4	Compulsion to contribute to congestion relief	No
5	Costs to locate to avoid congestion recognised	Yes, as the costs for firm access can be assessed against the costs of a different location
6	No cost if no congestion	Yes, on the basis that if there is no congestion, generators would not seek firm access. See note 3 below

Note 1. The OFA disadvantages existing generators that made a decision to locate where they are now for valid reasons, and subsequently they will incur increased costs to ensure they can still access the market as they planned. This is not necessarily equitable as they have no control over decisions of the new generator that causes the problem.

Note 2. Although the OFA model does not require all generators to contribute to the congestion relief, it is equitable as it provides all generators with the ability to assess the benefits and costs for gaining firm access.

Note 3. There is a concern that when a generator pays for firm access but this firm access is less than the current capacity of the network, the TNSP does not need to augment the network to provide the firm access right[1]. But it means the TNSP gets a payment for doing nothing. Does the TNSP get to keep this additional revenue to take to profit or is it taken into the allowable revenue cap and consumers pay less?

[1] What would occur in this case is that the generator with firm access would be notionally dispatched and generators with non-firm access would be notionally allocated the spare capacity in accordance with their bidding strategy so the firm generator is financially "whole"

Note 4. There is no certainty that the price offered by a monopoly TNSP for firm access will be at the most efficient level. There needs to be some mechanism to ensure that the costs incurred for providing the firm access are efficient and reflect the actual costs involved in the provision of the service. This will require the involvement of the AER either in a direct role as a regulator or an indirect role as an arbiter. The second interim report provides for this AER intervention to occur

Note 5. The OFA option clearly works where there is existing congestion as it places all generators on the same footing. Where a new generator is assessing its locational options, it would assess the cost of buying firm access at its preferred location and the costs of locating elsewhere. If it locates elsewhere, then there would be no congestion at its preferred location (benefiting existing generators) but imposing a cost for its alternative location, providing a barrier to entry.

Note 6. Intermittent generation will suffer a higher premium on its output compared to dispatchable generation. Intermittent generation has a much lower load factor than dispatchable generation but will incur the same price for firm capacity ($/MW). This means that its cost structure will have a higher comparable cost in $/MWh as a result of the OFA disadvantaging intermittent generation.

Note 7. There will be an impact on price taking generation (eg wind generation, and some dispatchable generation with low turndown capacity such as brown coal fired generators) as these generators may have to acquire more firm capacity than other forms of generation.

Note 8. There is a residual concern with the OFA, that once firm access is acquired, then a generator with firm access will tend to price its output at a higher price and therefore game the mechanism to the detriment of consumers. The structure of the reimbursement mechanism does not readily expose the generator with firm access to the wider market (which would impose competition on pricing).

In relation to note 7, in its preferred model the MEU proposed a more preferable solution to the complex arrangement under the OFA option for generators being dispatched in preference to the generator with firm access to have to pay compensation to the firm generator. The MEU proposal involved AEMO in the dispatch process. On notification to AEMO by a TNSP that a specific generator has firm access to a specific output, AEMO could introduce into the dispatch engine a control that when the point of congestion is reached, that non-firm generators would be required to scale back output in preference to the firm generator. This would overcome the complexity of requiring compensation to be paid and would directly expose the generator with firm access to the market and its inherent competition.

The OFA option does not make it clear what occurs if there is sufficient requirement for firm access that augmentation is required. As augmentation in a transmission network is quite lumpy, it is feasible that the augmentation would provide more capacity than has been contracted as firm. This means that generators with non-firm access could have access without paying for it. This would be inequitable and needs to be addressed.

The MEU sees that the OFA approach is a better solution to the status quo, but considers there are a number of aspects that need to be addressed which when incorporated will likely deliver a more efficient outcome for consumers.

The MEU also notes that implementation of the OFA option would be a major exercise as it constitutes a significant change to the market design. Despite this, the MEU considers that the benefits that will arise from the change are worth the effort and strongly supports its integration into the market.

2.4 Comparison between the two models

The report summarises the benefits of the OFA option well when it states that it will provide (page 45):

- *Improved support for a deep and liquid contract market* - by providing:
  - a mechanism for generators to obtain firm financial access that is not affected by congestion; and
  - a mechanism for market participants to obtain inter-regional access, which should encourage contracting between generators and retailers in different regions

- *More efficient investment in generation and transmission* - by establishing:
  - clear and cost-reflective locational signals for new generation investment through access pricing, encouraging the co-optimisation of transmission and generation investment;
  - market-led development of the transmission network, where generators' procurement of firm access would fund and guide network expansion; and
  - a new mechanism for the efficient expansion of inter-regional transmission capacity which would allow financially interested parties to internalise the costs and benefits of interconnector capacity.

- *More efficient dispatch of generators* - by reducing the current incentives on generators to engage in disorderly bidding.

- *More efficient operation of transmission networks* - by exposing TNSPs to some part of the value of network availability.

The MEU agrees with the report that these are benefits that will accrue to the market.

Prima facie, the OFA model introduces significant benefits to the electricity market merely by providing a targeted means for ensuring that generators can take direct action so that they are not constrained off due to congestion in the transmission network. At that level alone, it would seem that the benefits of the OFA outweigh the costs that making the change will incur. The discussion about the wider benefits provided in the report is extensive and sound, and extends the range of benefits that will accrue from the change.

3. Planning and Pricing

The second interim report comments that there is no evidence that there has been a lack of investment in inter-regional capacity being provided. The MEU finds this observation quite incongruous as there has been considerable observation that there has been consistent price separation between regions, to the extent that a SSNIP test carried out by NERA (in the analysis for the AEMC of the generator market power rule change proposed by the MEU) led the AEMC to consider that all regions in the so-called national market should be assessed as separate markets. The same outcome of this NERA analysis was previously reached by the ACCC in an earlier review on co insurance of NSW generators in the NSW region. The MEU had previously provided this reference to the AEMC.

As the NEM is really a series of connected regions, then it must be concluded that there is insufficient interconnection between the regions to provide a relatively seamless national market.

In addition to insufficient capacity across regional boundaries, there is clear evidence that the full carrying capacity of interconnectors is limited by constraints within separate regions that reduce the actual flows across boundaries. At is most obvious, this lack of intra-regional carrying capacity can be seen by the performance of the Murraylink interconnector.

It would be expected that at times of price separation between Victoria and South Australia, Murraylink would be operating at or near its rated capacity of 220 MW. In practice, at times of price separation Murraylink does not operate at this level because of constraints within the Victorian and SA regions. Decisions to strengthen the intra-regional elements of the networks are made by different parties, neither of which have an interest in enabling greater flows to other regions.

It was with this scenario in mind, that the MEU sees the need to increase planning of the NEM to be looked at holistically and that price signals be provided to develop what should be a truly national transmission grid that has considerably fewer constraints occurring so that there is in practice a more seamless market.

The MEU does acknowledge that a national grid without any congestion would be quite unlikely, and that some congestion is to be expected when assessing the overall efficiency but unless there is greater coordination of planning so that a holistic view is developed, there will be no notion of whether the current degree of interconnection is actually at the efficient level – a view that the second interim report considers is the case based on its view that there is no evidence of greater need for interconnection at present.

With this view in mind, although the MEU does not agree with the AEMC that there is no evidence of the need for more interconnection, the proposals put as part of the report for greater coordination and development of better price signals, are supported by the MEU.

3.1 Better coordination in planning

The report proposes that there be better coordination of planning and a requirement for closer development of investment proposals to maximise the benefit of transmission investment across the NEM. The report proposes (page 56):

- *Enhancing the role of AEMO as national transmission planner (NTP)* to include a short, as well as a long, term focus on nationally coordinated planning by:
  - reviewing draft TNSP planning and investment test reports;
  - providing demand forecasts for use in transmission planning;
  - providing an expert independent advisory role; and
  - assuming the Last Resort Planning Power (currently with the AEMC)
- *Enhancing the role of TNSPs in driving coordination* by:
  - supporting increased consultation between TNSPs to identify and implement cross regional network investment options;
  - aligning the regulatory control periods for TNSPs; and
  - formalising TNSP input into the NTP's annual strategic planning report to ensure that both local and national perspectives are captured and reflected in the longer term planning process

As a suite of changes designed to improve the transmission planning, the MEU considers that the report has identified appropriate changes that are likely to provide considerable benefit to the market and thereby provide a long term benefit to consumers.

3.2 Alignment of TNSP regulatory periods

The only concern the MEU continues to have relates to the recommendation to align control periods for TNSPs. The MEU does not agree with the AEMC that this is needed to provide better planning and, to the contrary, is likely to result in harm to consumers as consumers will have considerable difficulty in resourcing adequate responses to five different but concurrent applications for revenue resets. The MEU also has concerns that the AER will have sufficient resources to properly carry out that task as well.

The MEU recognises that the concurrent review of all TNSP resets provides a benefit in terms of the AER being able to provide a better assessment of investment by one TNSP that impacts other regions, but the core aspect of planning which leads to this holistic approach will not be carried out by the AER but by the TNSPs in concert with AEMO. It will be the TNSPs together with

AEMO that develop the RIT-T to substantiate an investment program. The AER involvement in the planning process is limited to ensuring the capex required to implement the proposals arising from the planning function and this could be provided by the AER accepting the recommendations of the jointly prepared RIT-T – an approach that currently applies. As there is flexibility in the amount of capex that might be needed through the existing capex allowance backed up by contingent capex proposals, the implementation of specific investments as a result of coordinated planning will not be put at risk by having staggered regulatory periods for the TNSPs.

In contrast, the ability of consumers to be involved in TNSP regulatory pricing resets will be heavily constrained by having concurrent regulatory periods. The MEU points to the conclusions of the Expert Panel examining the limited merits review process.

In its Review of the Limited Merits Review Regime Discussion Paper Issues and Questions for Stage Two (page 2), the LMR Expert Panel commented:

> "Whilst Stage One of the Review covered a range of issues, the Panel is minded to focus first on two related, broad areas of problems that were identified:
>
> - The tendency for the scope of reviews of regulatory decisions to be unduly narrow, such that the overall merits of the reviewable decisions on allowable revenues/prices were themselves never assessed.
>
> - An insufficiency of attention to the National Electricity Objective (NEO) and National Gas Objective (NGO), and hence to the long-term interests of consumers, in the LMR process. The Panel also noted the associated, and arguably more important, lack of attention paid to these matters in business and regulatory decision making prior to the appeals stage.
>
> Many of the other problems raised in Stage One are linked to one or both of these issues (e.g. **they give rise to problems of accountability and transparency, and to insufficient attention being paid to consumer and network user voices** at the appeal stage)…" (emphasis added)

The MEU notes that this observation is made in the context of the LMR appeals process, but the principles have equal application to the wider regulatory process. The MEU points out that curtailing consumer and network user input by creating a massive amount of work to be carried out in a very short timeframe, not only has the potential to limit stakeholder involvement in the regulatory process but to actually cause it to reflect less consumer input into the final decision.

The MEU considers that extreme caution needs to be taken when assessing changes to the regulatory processes that, in attempting to improve the outcomes from the planning processes, stakeholder involvement preferably should be enhanced and not reduced as is likely from having concurrent TNSP revenue reset reviews.

The report goes on to state that there are concerns about the “peakiness” of the AER workload, the report makes no mention as to the impact that such a proposal might have on stakeholder input. The MEU agrees with the report that , although the AEMC endorses “in principle” alignment of the regulatory control periods, further thought must be given on the issue due to other consequential effects. One such issue concerns the likelihood of implementing concurrently the capex programmes of all five TNSPs after a review and the inflationary pressures on costs.

3.3 NEM wide transmission pricing

The MEU has been a consistent supporter of common approaches being used across the NEM, including in pricing methodologies.

The MEU has noticed that the different pricing methodologies used across the NEM regions have resulted in different outcomes in different regions. The MEU notes that in the recent release of the draft report on DSP3 there is a thrust to increase the ability of the demand side to participate in the market and to influence market outcomes. Whilst there are different approaches used in pricing in different regions, the ability of consumers to have a coordinated response to the DSP3 proposals will be constrained. The MEU therefore supports a consistent pricing methodology being used across all TNSPs.

The report notes that this transmission frameworks review has a wider application than the current rule change proposal for inter-regional charging that is still under investigation. The MEU is a supporter of inter-regional charging provided that it results in a cost reflective outcome. Up to now, the IR charging proposals have resulted in quite anomalous and unacceptable outcomes.

Provided that the new common pricing methodologies result in cost reflective prices and allow for equitable cross border charging, the MEU supports the more far reaching pricing change proposal. The MEU sees that when pricing is carried out within a region, there is a view that such pricing outcomes are reasonably cost reflective. Applying the same tools as those used intra-regionally to address transmission NEM wide should result in a similar degree of cost reflective outcomes that currently occur regionally.

The MEU notes that it would be AEMO that would undertake this NEM wide transmission pricing review – the MEU agrees that AEMO is an appropriate body for this task and would be an adjunct to the processes that AEMO already undertakes in setting marginal loss factors.

The report then posits that an aligned regulatory review would assist in this process. The MEU sees that an aligned review process would be an advantage in setting national pricing but does not accept that the two must occur together. Providing each TNSP advises AEMO of the regulatory recovery that is required each year, it is irrelevant as to whether the annual allowances were set at the same time or were set at different times. In this regard, the MEU notes that the TNSPs already have quite significant variations in the amounts they have to recover annually due to under/over recoveries in the previous year, the over recovery of losses from the marginal loss factors used and the allocation of the IR settlement residues. When these variations are considered, the need to have common regulatory periods becomes quite immaterial.

In particular, the MEU notes that the role of AEMO in Victoria would have to change, where AEMO is the planner, procurer of augmentations and operator of the transmission network whereas in all other regions the jurisdictional TNSP is responsible for these functions.

To overcome this inconsistency, the report recommends that AEMO no longer have these functions in Victoria and that they be transferred to the Victorian transmission network provider SP Ausnet resulting in SP Ausnet having the same functions in Victoria as other TNSPs have in their regions. The MEU sees that such an outcome is sensible and pragmatic, although it does require SP Ausnet to agree to accept the increased responsibilities.

3.4 Comparison with options proposed previously

The MEU considers that the report has developed a sensible and pragmatic outcome from its analytic work and has recognised (in the main) the concerns that stakeholders have raised in relation to the number of options proposed in the first interim report.

Other than its concerns about not incorporating the wealth transfers from consumers to generators in the RIT-T (see section 1.2 above) and the desire to align TNSP regulatory periods (see section 3.2 above) the MEU considers that the suite of planning and pricing proposals provides a considerable improvement to the current processes.

4. Improving the connection framework

The MEU notes that the AEMC has recognised that there is a considerable difference in the lack of an equitable negotiating position applicants for connection of the shared network have when dealing with a monopoly, whether this monopoly is a transmission network service provider or a distribution network service provider. DNSPs have little trouble in negotiating with TNSPs because DNSPs are permitted to pass through to consumers the outcome of any negotiations they have with TNSPs.

During the consultation process regarding the connection element of this framework review, there has been a common view from both consumers and generators that there is no real negotiation possible with a monopoly service provider[2]. The analysis undertaken by the AEMC supports the view provided by connection applicants (including MEU member companies) that the current process imposes many impediments and significant costs, and is quite one sided as the current approach favours the monopoly regardless of the size of the applicant.

4.1 Connections

The report correctly identifies that the process for negotiating connection arrangements is fraught and all of the negotiating power lies with the network provider.

In relation to the issues identified in the report, MEU members have reported that when dealing with NSPs, the attitude in frequently one of “take what we offer or have nothing”. This applies in terms of the detailed arrangements and standards of supply through to the price offered. In one example, the MEU member cited a case where the costs of a connection calculated by an experienced independent consultant was half the amount quoted by the NSP. When confronted with the independent cost build up, the NSP declared that they would not change their view on the cost. Other examples concern the lack of timeliness in responding to requests for connections and the numerous impediments raised that discourages connections or reduces the commerciality of new connections.

The proposals included in the report go some way to minimising the ability of an NSP to impose its costs on a new connection, and to develop a methodology whereby the connecting party can be assured that the costs associated with the connection are reasonable and not unnecessarily inflated. The MEU supports the proposals.

[2] This applies equally whether the monopoly is an electricity TNSP or DNSP and also applies to the same extent when dealing with gas NSPs.

However, the MEU considers there is a need to ensure there is an ability to seek a form of arbitration in specific instances. The MEU considers that constraining the AER to only be able to enforce requirements of guidelines will not be sufficient to ensure that the NSPs act in the most equitable way. Allowing the connecting party the ability to appeal to the AER should it consider it is not being provided with an equitable outcome, must be a provision within the Rules.

The MEU supports the principle that there should be standard terms of contract for a connection agreement. However, MEU members have reported that such standard terms currently in use are extensive and transfer considerable risk to the connecting party, perhaps more than is appropriate. It is suggested that because of this, there needs to be some methodology implemented which assesses the standard conditions of agreement to ensure they are equitable and balanced. It achieves little if the published standard agreements are heavily biased in favour of the NSP.

4.2 Extensions

The report describes well the challenges faced in managing extensions to the shared network. The MEU supports the proposals made in the report. This support is only qualified by other comments made in this section 4.

4.3 Clarifying the rules

The Report, in the analysis of the issues under this section, provides a good assessment of the challenges faced. The experience of MEU members in relation to the issue of how charges are shared when load and generators are both connected to the same assets provides an answer to one of the questions raised in the report.

Where a load and a generator are both connected to the LV side of the same transformers which provide step down/up provided by the TNSP, the payment for the use of the assets to connect to the shared network is all charged as an exit charge, with the generator not paying an entry charge. This means that the generator gets a “free ride” in relation to entry to the shared network at the expense of the consumer. This charging has been tested with the regulator and the decision made was that the generator should continue to get the “free ride”.

In box 6.4 describing the connection charging used in New Zealand provides a more equitable outcome in relation to the connection charge, where both the consumer and the generator both contribute to the cost of the connection in proportion to the Anytime Maximum Demand and Anytime Maximum Injection. Such an approach is equitable and consistent with other charging approaches.