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AEMC Ref: EPR0015: Draft Report

13 August 2009

The Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

DRAFT REPORT "REVIEW OF NATIONAL FRAMEWORK FOR ELECTRICITY DISTRIBUTION NETWORK PLANNING AND EXPANSION"

I refer to your request for submissions on the AEMC's Draft Report of the "Review of National Framework for Electricity Distribution Network Planning and Expansion". ETSA Utilities submission is provided below.

Introduction

ETSA Utilities is already subject to a similar reporting regime to that proposed in the AEMC Review. Our current requirements are detailed in ESCoSA Guideline 12 "Demand Management for Electricity Distribution Networks". These arrangements were implemented in 2003, reviewed during 2006 and amended in 2007 after extensive public consultation. We consider that these arrangements should be used as the basis for the national regime.

ETSA Utilities considers that the currently jurisdictional arrangements, in SA provide the appropriate balance between cost and benefits for the availability of information to Demand Management proponents. Any deviation from these arrangements should only be implemented where there is a net public benefit.

Executive Summary

We broadly agree with the AEMC that the new requirements will not be unduly arduous provided that:

1. They are a replacement for existing jurisdictional requirements and not an addition to them. The importance that this issue is addressed cannot be overstated. Further, we encourage the AEMC to engages with the jurisdictional regulators to ensure that they support the rule requirements.

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2. The recommended minor changes to the content of the DAPR be accepted, especially the ability of the DNSP's to use their own planning criteria to identify network limitations so that we avoid unnecessary duplication of our existing planning processes.

3. The recommended minor changes to the RIT-D are accepted to reduce some of the overhead in the execution of the tests and to improve our ability to respond to major customer connection requests under the new regulations.

We have estimated that without our proposed amendments the requirements as drafted would require approximately three additional full time equivalent employees.

In addition given the size and scope of the changes ETSA Utilities suggests that a review of the DAPR and the RIT-D processes be undertaken 24 months after they are placed in force to assess their cost and effectiveness.

Our detailed response has been split into two sections: the first section describes the significant concerns and issues we have with the Draft at a broad policy level and the second lists some detail points in the specification section that we believe could be improved.

Chapter 2 - Annual Planning Process

2.2 Scope and Requirements

ETSA Utilities is in broad agreement with this section except as noted in the detailed comments on the Framework specification at the end of this document.

2.3 Demand Side Engagement Strategy

Provision of the information required for the document can be achieved at reasonable cost. However, each non network proponent may require specific additional information to allow evaluation of the suitability of their proposal. Dependent on the level of response from potential proponents this may result in considerable cost to the DNSP to support the enquiries in a timely manner.

Consideration should be given by the AEMC to how these additional costs can best be passed through to end use customers or applicants.

We agree with Electricity Network Association response that there is no need for further specification on the content of the document

The merit of providing a public database is understood but commercially sensitive information (and privacy obligations), may prohibit the publishing of the detailed information required to understand the reasons for the acceptance or rejection of a proposal, as these will relate to technological advances or costs. In particular, one regular reason why non network solutions are not accepted is related to the cost, relative to the deferment savings – a simple NPV benefit test should be acceptable as a reason without the need to divulge specific details? (Due to the nature of the work required in different parts of the network the costs can vary dramatically for similar capacity augmentations – what may not be accepted at one location due to cost vs deferment savings may well be attractive in another location).

Assuming this simple test will apply, it is proposed that only those proposals that address the criteria as stated in the Demand Side Engagement Facilitation Process Document in point (iv) and (v) would be published. These are deemed as being beneficial in educating non network proponents of successful or non successful applications.

Furthermore, ETSA Utilities believes that the AER rather than the individual DNSP is the appropriate body to build and maintain the database. Having a single nationwide resource rather than a disparate collection organised by each individual DNSP would:

- Reduce the overall costs of the database(s);
- Improve ease of access by interested parties; and
- Simplify cross jurisdiction comparison and therefore improve the promulgation of best practice.

2.4 Publication of Distribution Annual Planning Report

ETSA Utilities supports the publication date of December 31st as this provides time to complete the planning process in the light of revisions to forecast peak demand from the previous summer's heat wave.

ETSA Utilities sees no need for a mandatory public forum to discuss the DAPR as the distribution system is essentially local in nature (unlike the transmission system) and therefore public engagement is best done locally in response to specific developments or concerns. We also believe that there is plenty of opportunity for community groups, councils, interested parties etc. to raise specific concerns through existing communication channels and as a consequence that a public forum will simply add to costs without any additional benefits (ie no increase in feedback from the community).

2.5 Joint Planning

ETSA Utilities believes that current Joint Planning regulations/arrangements are working both successfully and cost effectively in South Australia.

Any change to these practises should be justified by a cost benefit analysis and only done if there are demonstrated savings or significant additional benefits.

Chapter 3 - Annual Reporting Requirements

3.2 Context of Annual Planning Report

ETSA Utilities considers that it is imperative that the existing jurisdictional requirements are replaced by this proposal. Otherwise, significant additional costs will be incurred to comply with the two sets of reporting requirements.

In addition, significant costs will be incurred by some DNSPs with the addition of two items to the DAPR as these require a major duplication of the existing planning processes for most jurisdictions. These items are:

- The requirement for winter and summer load forecasting rather than just peak load forecasting; and
- The use of criteria other than the DNSP's own planning criteria to identify system constraints.

ETSA Utilities considers that the aim of the requirements is to identify when a DNSP is likely to undertake work to reinforce the network. This will enable proponents to make proposals to reduce demand to enable the deferral of the work.
The majority of DNSPs' plan their reinforcement works using two pieces of information, namely:

- the summer or winter peak demand forecast (generally not both); and
- the DNSP's System Planning Criteria.

The use of the above two requirements in the AEMC proposal duplicates cost of preparing the forecasts and provide signals to proponents that indicate that reinforcement work is required when it is not. A summer and winter forecast should only be prepared when those forecasts will lead to reinforcement work by the DNSP.

3.3 Scope of Reporting Requirement

Definitions of sub-transmission and primary distribution feeders

ETSA Utilities believes that the reporting requirements should include all elements of the sub transmission network including lines and not just sub transmission assets and zone substations as it is often the elements in a network that are the limiting constraint. If lines are excluded as proposed it will be difficult for DM respondents to understand the context of much of the work being undertaken.

We agree with the reporting of '*primary distribution feeders'* as redefined below on an exception basis and with a shorter forward view, as work on these is typically less expensive and more subject to variation in demand.

In the document there are two definitions of a sub transmission asset. In the main body of the report it states as 'greater than 33 kV' and in the definitions section of the framework it uses '33 kV or greater'. This latter definition is problematic as ETSA Utilities uses 33 kV as a rural distribution voltage and would therefore include such items as:

- 33 kV / 433 V distribution transformer (currently 708 installed)
- SWER isolating transformer (currently 115 installed)
- 33 kV / 33 kV regulators (10 installed)
- Small 33 kV / 11 kV transformers (currently 67 < 5 MVA installed)

ETSA Utilities believes that it would be clearer to define sub transmission assets as in the main body as being all assets connected with a primary voltage greater than 33 kV.

From the definition of 'Distribution line' in the NER the definition of 'Primary Distribution Feeder' includes all distribution lines operating at 11 kV or higher, whether or not they would be regarded as a primary distribution feeder in the traditional engineering sense. In particular using this definition the following would be required to be reported as separate lines:

- All 19.1 kV and 12.7 kV SWER lines
- All 11 kV spurs that branch off the 33 kV rural distribution feeders
- All single phase spurs that branch off of either 11 kV or 33 kV distribution feeders
- All 66 kV sub transmission lines

The definition also misses a number of historical primary feeders in Adelaide currently supplied at 7.6 kV. It also conflicts with the AER definition used to define feeders for the STPIS scheme which defines these by function rather than voltage level.

ETSA Utilities believes that it would be more appropriate for the DAPR to use the same definition of feeder as used in the AER's STPIS scheme as this will allow reuse of information between the two reporting requirements and remove a major source of confusion to the general public. Alternatively we offer the following definitions:

> *Sub Transmission line* – a line connecting a *sub transmission asset* to either the *transmission* system or another *sub transmission asset*.
>
> *Primary distribution feeder* – a line connecting a *sub transmission asset* to either other *distribution lines* that are not *sub transmission lines* or to *distribution assets* that are not *sub transmission assets.*

Smart Metering

Limiting the reporting of SCADA investment to that associated with smart metering precludes investments made in SCADA and smart grid technologies for other reasons (eg that may enhance the real time metering information on a much wider scale and at critical points within the network). We believe that it is probably better to simply request that the DAPR report significant investments in this area and leave it up to the DNSP to decide how best to report its broader progress.

At a simplistic level the metering could be summarised with the number of meters installed or percentage of load that has been metered. This may provide some minimal benefit to non network proponents with some assurance of the error levels of the provided forecasts and timing of peaks.

3.4 Identifying System limitations

ETSA Utilities suggests that system limitations should be defined in terms of the planning criteria used by the individual DNSP and not in generic terms such as 'normal cyclic rating under normal operating conditions'. The consequences of having two sets of criteria (one for identifying required work and one for reporting) would be:

- The DNSP reporting constraints where no work is required and not reporting constraints where it is required urgently;

- A significant increase in the costs involved in preparing the DAPR as our existing planning documents and processes could not be used.

ETSA Utilities believes that any attempt to achieve national consensus on reporting would be better handled through first obtaining a national consensus on planning criteria.

ETSA Utilities does not produce winter load forecasts as our network has been summer peaking for many years. To do so would double the cost of producing the forecasts and would only be required for reporting in the DAPR. We strongly suggest that the requirement for summer and winter forecasts be replaced by a requirement for a single peak forecast (summer or winter) and possibly by the number of hours per year that 95% of peak is expected to be reached if some measure of diversity is required.

There are a significant number of problems when reporting or forecasting the level of embedded generation in our networks:

- It is difficult to be precise about the location of micro units (< 30 kW) as these have little impact on peak system performance and are therefore not tracked by locality;
- We only become aware of embedded generation when a import/export meter is requested. We believe that there is likely to be considerable off grid and local supply micro units where power is not exported to the network that will consequently be invisible to the DNSP's;
- Forecasting the future penetration of DM is virtually impossible as this depends on micro economic factors such as government subsidies over which the DNSP has no control.
- Where units are of a significant size companies may approach the DNSP with a proposal in confidence which will not therefore be able to be included in the forecasts until the project reaches a committed stage, further making the forecast unreliable.
- Finally we have little or no visibility or knowledge of when units are decommissioned, removed from the network for repair or simply not run.

Consequently ETSA Utilities suggests that reporting on embedded generation be at the system level by recorded installed capacity by category (PV < 1 MW, wind < 1 MW, Other < 1 MW, PV > 1 MW, Wind > 1 MW etc.) and at the Sub Transmission level only where the unit has an installed peak capacity > 1 MW and is monitored in the DNSP's SCADA system.

ETSA Utilities is also concerned with the information required to be reported for primary distribution feeders, as based on our ESCoSA Guideline 12 reporting experience we believe that the proposed list will add significant costs with no benefit to DM proponents. In particular:

- The reporting of all options considered, which will essentially be the same list of options repeated for each feeder but requiring separate explanations of why the majority are too expensive or not technically appropriate; and
- The reporting of all potential connection points at which DM may be applied as there may be up to a thousand customers on an urban feeder and it also raises issues of customer confidentiality concerning the reason for which electronic data is collected.

In its place we suggest the following elements;

- Feeder identifier and the zone sub station from which it originates;

- The size, season and year, and cause of the constraint (Overload at N, lack of N-1 transfer capacity etc.);
- The proposed solution to the constraint (load transfers to other feeders etc.); and
- The size, duration and broad location at which demand reduction must occur if the preferred solution to the constraint is to be deferred for one year.

While ETSA Utilities currently reports regionally, it develops and ranks projects on a state wide basis. It does occasionally develop regional plans for a portion of its network out to 20 or more years, typically as a response to a requirement for a major infrastructure project such as a new transmission connection point. However, such plans are expensive and difficult to get right and are therefore only warranted on an exceptional basis. Consequently ETSA Utilities sees no economic justification for the compulsory development of these plans where a major investment is not planned.

3.5 Reporting on Network Investments

ETSA Utilities supports the reporting requirement to provide, a summary of the STT or Final Project Assessment report for each project assessed during the current calendar year and a list of those projects that will be assessed during the coming year. However, we believe that this should be a concise summary and not duplicate information which is readily available in the already published documentation. In particular, the requirement to report on all options rather than just the preferred option and to include impacts on connection and DUOS charges is excessive.

Chapter 4 - Regulatory Investment Test for Distribution

4.2 Amalgamation of Reliability and Market Benefits Limb

ETSA Utilities strongly supports the adoption of a single test which should include all relevant costs and benefits. However we have significant concerns about the details of the tests and the cost implications of some of those details.

We have one reservation with this section in that negative net present values should be permitted whenever a DNSP is compelled to resolve a constraint by an external party or agreement and not just by its schedule 5 obligations. In particular this should also include the DNSP's planning criteria as published in the DAPR as these have been established to ensure compliance with jurisdictional service standard obligations (eg reliability standards).

4.3 Scope of investment subject to the RIT-D

ETSA Utilities is uncomfortable with the $2 million threshold as this is the current ESCOSA Guideline 12 amount which has been fixed since 2003. Since then increases in construction costs have significantly reduced the real level of the threshold. We suggest that this should be increased to at least $3 million in line with inflation or preferable 1% of annual revenue requirement, as this is half of the AER's 'material projects' threshold of significant projects which is 2%.

We also believe that there is a need for the definition of the term 'economically feasible' as otherwise this is likely to become a point of major contention and appeal.

4.4 *Exemption from the RIT-D*

ETSA Utilities believes that the wording with regard to large customer connections (> $2 million) is contradictory as it is difficult to identify any connection assets that would not eventually be part of the shared network, therefore seeming to defeat the point of the exemption. This is also reflected in the description of the text regarding Urgent and Unforseen Investments which specifically excludes large customer connections that may be required at short notice.

Further, the question of just what is a negotiated service or a direct service needs clarification in the case of where a new customer connection causes an augmentation of the network that is only partly paid for by the customer.

We believe that the approach taken by ESCOSA (see table below) under the Guideline 12 test is a better approach and has the benefit of 6 years of actual experience and a thorough review of its effectiveness with substantial public consultation by ESCOSA .

Table 3:1 – Input Criteria for the Reasonableness Test [1]

WHERE AN RFP IS APPROPRIATE	WHERE AN RFP MAY NOT BE APPROPRIATE
Where the capacity constraint is load growth driven; The load reduction may be achieved within the required time frame; and The indicative cost of demand management is comparable with or less than the least cost network option based on knowledge of previous evaluations or nature of load obtained in data gathering exercises. (e.g. via public information gathering process for specific constraints)	New development release areas (large release areas where dedicated assets are required to supply new customers). *ETSA Utilities to assist developers, builders, and local councils in identifying demand management and energy efficiency measures in new developments that can be used to reduce electricity demand* Network enhancement is required for 'quality of supply' reasons or age/condition related asset replacement – (*i.e. infrastructure expenditure that is not primarily related to capacity constraints).* New large spot loads where there is insufficient time to investigate/implement a demand side program. Where constraints result from a known single or a dominant group of customer(s). *In such cases ETSA Utilities or a demand management service provider would obtain all relevant information regarding demand side solutions from the customer without the need for a formal request for proposal.*

This point is of considerable importance as the inclusion of large customer connection projects for which little notice is given in the RIT-D process will impact significantly on the ability of a DNSP to act quickly to meet the requirements of customers.

In addition as the length of time to complete an RIT-D is in the order of a year but the exemption only applies to projects that must be completed within 6 months a problem occurs for those projects for which the DNSP has received notice of between 6 months and 1 year. ETSA Utilities suggests that this be resolved by increasing the exemption period to 1 year.

ETSA Utilities believes that with the proposed increased threshold (ie $3m) it is not necessary to exclude primary distribution feeders as the bulk of the work will be excluded by the increased

[1] Demand management for electricity distribution networks - electricity industry guideline no. 12 – ESCOSA. Available from http://www.escosa.sa.gov.au/site/page.cfm?u=55#e72

threshold and the elements that aren't, are significant enough to make the Specification Threshold Test sensible. This is provided that the fore mentioned issues with large customer connections are resolved satisfactorily.

4.5 *Specification Threshold Test (STT)*

ETSA Utilities requests that the clause in the specification 3 (c) (i) 2 be clarified to reflect the main text and remove any doubt about the application of this clause. In particular to clarify that this clause only applies when the **end solution** may have an adverse impact on end use customers and not the constraint itself.

A reasonable estimate for the cost taken to do the test for a specific augmentation project is likely to be in the order of $4,000 given the writing, review and publication requirements as specified by the AEMC. If a DNSP considers that the RIT-D is a certainty, due to the size or nature of the project or the obvious potential for DM, the DNSP should not be required to undertake a STT. ETSA Utilities suggests that an STT should only be mandatory where a DNSP will not be producing a specification and putting the project out to public comment.

4.6 *The Project Specification Stage*

ETSA Utilities notes that the major element of interest to DM solution providers – the annual deferred augmentation charge – i.e. the value of any deferral in the network solution has not been included in the reporting requirements. Also, the costs of non DNSP options are unknown and should be excluded from the specification stage as the determination of these costs is after all one of the major reasons for the specification.

4.7 *Project Assessment Process - Consideration of Market Benefits and Costs*

ETSA Utilities strongly supports AEMC instruction to the AER to include some worked examples of the application of the test. In particular, the treatment of DUOS, TUOS and connection charges needs to be clarified and the inclusion of 'other parties' costs – which parties and which costs.

Chapter 5 - Dispute Resolution Process

5.2 *Scope*

ETSA Utilities broadly supports the Dispute Resolution Process as defined in Chapter Five and in particular:

- The use of the AER as an impartial arbiter of the dispute;
- The limitation of the dispute to the RIT-D's and how appropriately the DNSP has carried out its obligations under the rules. In particular, we support the exclusion of forecasts made in the APR;
- The time frames as outlined are also acceptable, provided that the AER is given the power to impose a deadline data on the furnishing of additional information in order to avoid one party or the other from delaying the determination indefinitely.

Detailed Comments on the Specification Framework

Annual planning process and report

Section 3 a (i)

- No definition has been provided for 'distribution feeders', 'system level' and 'embedded generation'.
- Forecasts should also be required for sub transmission lines and transmission connection points, the latter with a 10 year horizon
- Forecasts should also be for contingency conditions as substantial load transfers may occur across the sub transmission network.

Section 4 b (vi)

Suggest add a reference to the relevant sections of the rules as has been done for clause (xii) e.g. section 5.5 (f)

Section 4 b (viii)

Should be changed to include only that information that the DNSP is responsible for producing and not include broad references to the mountain of information on DM that is publicly available from other sources.

Section 4 (e)

Should be changed so that the AER constructs and maintains the database from publicly available information provided by the DNSP's e.g. Results of the Tests and RIT-D's.

Section 4 (f)

The reference to 'specific constraints' should be removed with all participants on the register being advised of all publications. ETSA Utilities currently has over 220 parties on its register and to identify interest by specific constraint would be both time consuming and require the interested party to notify ETSA Utilities of each constraint that it was interested in, defeating the purpose of the register.

Section 4 (g) (new clause)

'The document should be provided to the AER for publication as part of the database established under clause 4 (e)'

Section 6 a (iii) this clause is ambiguous as its meaning could be taken to include small components such as cross arms, insulators, protection relays etc. Suggest that it is changed to reflect the actual types of assets that the AEMC wish to have included in the annual report e.g. sub transmission lines, primary feeders, zone sub stations.

Section 6 a (iv) the relationship between this clause and clauses 6 b (I) and 6 (d) needs to be clarified. If it is intended that this clause should include the planning criteria which are used to identify network elements requiring augmentation then this should be plainly stated.

Section 6 b (ii) the paper lacks a definition of zone substations and it is unclear how these differ from sub transmission assets. We suggest that 'sub transmission lines' are added to the list, perhaps both could be replaced by the term 'Sub transmission network'. As 'total capacity' and 'firm delivery capacity' are not defined ETSA Utilities assumes that this is in terms of the DNSP's own planning criteria, an approach we agree with.

Section 6 b (iii) similar comments to clause 6 b (ii) with regard to definition and scope. In addition 'embedded generation' needs to be defined and a size limit included as it is impossible to forecast the presence or absence of small residential units of only a few kVA. As stated previously suggest a minimum size of 1 MVA per unit.

Section 6 b (iv) Suggest adding the term 'approximate' before location as location is often not clearly identified until after property has been secured.

Section 6 b (vi) the term 'potentially unreliable assets' is undefined and without a specified failure rate meaningless as all assets are 'potentially' unreliable. Suggest that the clause be rewritten to reflect what is actually required. Perhaps 'all major assets scheduled for replacement due to age within the planning period' with major assets being defined as an asset with a value of > $2 million.

Section 6 c The term 'normal cyclic rating' is undefined and in standard use applies to a transformer, not a line. A better term might simply be 'capacity' with capacity being defined by the planning criteria included in section 6 a (iv). This would then include those situations where a line is constrained by contingency transfer capability, voltage levels or protection issues and not just by the line thermal rating.

Section 6 c (i) The term location is ambiguous and we believe originating Zone Substation would be clearer. Also some form of feeder ID might be useful.

Section 6 c (iii) as above for 'normal cyclic rating'

Section 6 c (iv) As the number of potential solutions is large and the list of feeders is long we suggest only the preferred solution be included.

Section 6 c (v) Suggest change 'month' to 'season'. Suggest also adding the number of hours that the reduction is forecast to be required for as this can be easily determined from the Load Duration curve for the feeder and is vital to a proper understanding of the economics of a Demand Management solution. Connection points in this sense would mean customer connection points of which there may be over 1,000 on an urban feeder. We suggest a much higher level is chosen, perhaps feeder and zone sub station.

Section 6 d (i) Suggest adding sub transmission lines. The term 'Zone Substations' is undefined and is probably made redundant by the phrase 'Sub transmission assets', perhaps both could be replaced by the term 'Sub transmission network'.

Section d (1) 2 Considerable small asset replacement occurs on an ongoing basis to a sub transmission network; often for only a few thousand dollars per unit. Suggest that a threshold be added so that only major assets are included as a result of this clause, perhaps $2 million.

Section 6 d (ii) As above for the requirement for 'month' of overload.

Section 6 d (viii) Similar comments to section 6 c (v) regarding month and duration.

Section 6 e (vii) Connection charges for new supply tend to be very specific to the timing, size and nature of the load as they are calculated by how they impact future augmentation dates of related assets. As such, how a 'generic' charge is impacted by a particular augmentation is impossible to say except on the most trivial basis as an increase in the threshold level for payment of the charge. It is also expensive and difficult to calculate as it is a function of the network as a whole, from the load back in some cases to the transmission connection point. DUOS charges are also problematic as they are in the end not set by the DNSP but by the regulator and are determined by a complex mix of depreciation and consumption. Any figure derived from the asset value of the augmentation is therefore likely to be ultimately misleading. Perhaps a way forward might be to set a threshold and only include those projects that will raise the DUOS charge by a significant amount, perhaps 1%.

Regulatory Investment Test - Distribution

Section 2 a (vi) Few, if any connection assets will not become part of the DNSP's shared network therefore this clause would appear to be meaningless.

Section 2 c (i) As the time frame for the completion of the process from identification of the need to completion of the RFP evaluation is in the order of 1 year the 6 month limitation on this exclusion introduces a 6 month gap in the process. Suggest that this frame should be extended to 12 months or to the minimum period required for the full RIT-D process to be completed.

Section 2 c (ii) The problem with this clause is in its consequences. If the circumstances were within the control of the DNSP – e.g. a planning failure to account for a heatwave then the DNSP is bound by this clause to follow the RIT-D process and consequently to let the network be materially adversely affected. ETSA Utilities recommends that this clause be removed. The public embarrassment of admitting the failure in the APR should be sufficient punishment without inflicting damage or risk of damage on innocent third parties.

Section 2 c (iv) ETSA Utilities requests that the AEMC add a new clause to the list of exemptions to specifically include requests from external parties for connection within a period that does not permit the performance of an RIT-D.

Section 3 (b) ETSA Utilities believes that this clause should be deleted. Credible options at this stage of the process should be identified based solely on their ability to address the constraint, economic and technical feasibility and likely availability. Questions of ownership, energy source, technology etc. are vital but only at the end of the process and then based on commercial negotiation and in the light of evidence brought to light by the RIT-D process.

Section 4 a (v) Suggest the addition of the words 'Existing or committed' are added to qualify the type of embedded generation units.

Section 6 b (iii) That this clause be rewritten to reflect the accompanying text in the main document to reflect that this only applies where the final solution to the constraint will materially impact the end user and not the presence of the constraint itself.

Section 6 c (ii) Given that ETSA Utilities currently has in the order of 220 parties registered on its Register of Interested Parties we would prefer to inform them by E – Mail of the presence of the completed test on the web site and not send to them the test itself. (Sending large files uninvited to e mail boxes is considered by many to be a significant breach of etiquette) Therefore we suggest that this clause be changed to read 'Notice of completion of the Specification Test report …'

Section 7 a (i) Similar comments to section 6 b (iii.

Section 7 c (vi) 3 It is unlikely that the DNSP can comment with any accuracy at all on the likely costs of options that may be provided by external parties as these involve a significant number of variables such as profit margin and internal labour costs that the DNSP has no visibility to or experience with. ETSA Utilities therefore recommends that clause three be merged into clause two and that cost data is only to be supplied for network investment options proposed by the DNSP.

Section 7 e Same comments as for clause section 6 c (ii). An Email notifying the registered parties of the presence of the document on the DNSP web site should be all that is required.

Section 8 b Similar comments to section 7 e.

Section 8 f ETSA Utilities believes that it is in the public interest that if an interested party requests a meeting then that meeting should be had. To provide a clause stating that the meeting is only required if two parties request the meeting is just to invite gaming of the regulations and will not deter nuisance requests.

Section 9 a (i) Similar comments as to those made for clause 8 b (iii)

Section 10 c Similar comments to section 7 e.

Section 10 f ETSA Utilities fully supports the use of the final assessment reports in considering the regulatory proposals under Chapter 6 of the NER.

Section 11 (i) A new clause to empower the AER to set a date by which additional information must be supplied for it to be considered in the dispute resolution process. Currently as stated a third party may significantly hold up the process by being late in delivering information requested to the AER.

> "(iii) the AER may set a date by which requested information must be provided for it to be considered in the determination."

If you have any queries or questions on our submission please contact Mr Grant Cox on 08 8404 5012

Yours sincerely,

Eric Lindner
General Manager Regulation & Company Secretary
ETSA Utilities

GTC/no EU_Submission_the_Review_National_Framework_EDNPC&E_Aug09.doc