Measurement of Outputs and Operating Environment Factors for Economic Benchmarking of Electricity Transmission Network Service Providers

Briefing Notes prepared for
Australian Energy Regulator

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EXECUTIVE SUMMARY

The Australian Energy Regulator (AER 2012a) has indicated that economic benchmarking will be one of a suite of assessment techniques to be detailed in its forthcoming expenditure forecast assessment guidelines. The AER is consulting extensively with network service providers in developing its approach to economic benchmarking. This includes conducting a series of workshops to seek feedback on the appropriate outputs, inputs and operating environment variables to be used in economic benchmarking.

The AER has engaged Economic Insights to assist with this consultation process. These briefing notes provide background material for the fifth workshop which is on measuring outputs and operating environment factors to be used for economic benchmarking of electricity transmission network service providers (TNSPs).

Outputs – issues for discussion

Data requirements

The TNSP output data requirements to implement economic benchmarking are listed in table 1 in section 3.2 along with preliminary variable definitions and an indication of whether the variable is currently collected in TNSP Information Disclosure Requirements (IDRs). The variables listed are required to support the short listed outputs and a range of anticipated sensitivity analyses.

1) *Are there any variables missing from table 1 in section 3.2 that should be there?*

2) *Are the definitions proposed appropriate for economic benchmarking?*

3) *Should any of the definitions be altered to ensure consistency across TNSPs?*

Network capacity, peak demand and throughput

Many analysts have likened an NSP's role to the provision of a road network. The road network operator has to make sure roads go to appropriate places and have sufficient capacity to meet peak demands but the road operator has little control over the volume of traffic on the road, either in total or at any particular time. Consequently, the primary functional output of an NSP is provision of adequate – but not excessive – capacity to meet demand. This points to the inclusion of system capacity as an output, either directly or by using peak demand as a proxy.

There are arguments for and against including system capacity versus smoothed maximum demand as a functional output. On balance, we are of the view that both measures warrant further investigation and sensitivity analysis should be undertaken. System capacity taking in both line length and transformer capacity is likely to be the best option in the short term as it requires a minimal number of observations to implement. Once sufficient data observations become available inclusion of smoothed maximum demand should be investigated, along with more sophisticated measures of TNSP system capacity.

Given that throughput is what customers consume directly, the relative robustness of throughput data and its inclusion in nearly all previous economic benchmarking studies, we recommend that throughput still be considered for inclusion as an output, although it is likely to receive a relatively small weight in light of its small impact on network costs.

4) *How should system capacity be measured?*
5) *If peak demand is used, should it be actual, smoothed, weather corrected or forecast peak demand?*
6) *Is there a case for including throughput as a TNSP output?*

Calculating output weights

There are three broad options available to form cost–reflective output weights for use in economic benchmarking:

- estimate the weights from an econometric cost function;
- use weights from previous cost function studies from a broadly comparable sample, or
- obtain estimates of the relative cost of producing each of the specified outputs from the TNSPs themselves.

Provided a relatively small number of outputs are included, the log linear cost function can be estimated on cross sectional data while the Leontief cost function can be estimated with a relatively small number of observations for each of the included TNSPs. While drawing on the results of previous cost function studies is reasonable where the earlier studies were of industries directly comparable to the one at hand, it has the potential limitation of restricting the choice of outputs to the same components as used previously.

While it is desirable to estimate the output weights to be used in economic benchmarking by objective and reproducible independent means, another alternative is to request the TNSPs to provide estimates of how their total costs should be allocated across the included output components. This process could also provide a useful 'sanity check' for output weights estimated by other means. The cost allocation should use a fully distributed costs method where possible and be consistent with approaches being developed in the category analysis workstream.

Including reliability measures as outputs

There was some concern expressed at the second workshop that basing the reliability output heavily on the current STPIS parameters may not be appropriate as they are geared to time–series rather than cross–sectional comparisons. Economic Insights agrees that using the market impact component of the STPIS for economic benchmarking may be problematic in this regard. However, we consider variants of the four STPIS service component indicators – average circuit outage rate, loss of supply event frequency, average outage duration and proper operation of equipment – are potentially suitable.

It is desirable to have a way of including standard reliability measures as outputs in economic benchmarking studies, including index–based methods which are the most likely methods to be able to be implemented initially. We propose two alternative means of doing this be further investigated.

The first method involves including total outage minutes or total number of outages as an undesirable output. By giving the reliability measure a negative weight, it is then treated as a 'bad' rather than a 'good' output and reducing the value of the measure (ie improving reliability) will be consistent with increasing overall output.

The second method we believe warrants further investigation is to form a benchmark level of the maximum acceptable overall outages and subtract the actual level of outages from this benchmark level. This subtraction would produce a variable with the standard output characteristics where a higher value represented more of the output.

Rather than include reliability as an output, some studies have included customer–minutes lost as an input whose cost is added to the NSP's operating and capital costs. This approach also warrants consideration.

A good case can be made that reliability outputs should be valued according to the customer's valuation rather than the TNSP's costs of improving reliability. We recommend adopting the STPIS valuations of customer outages. For the first approach of including outages as an undesirable output, the value of customer outages would enter as negative.

For the second approach above of including the difference between observed reliability and a benchmark worst acceptable reliability performance, the transformed reliability output would simply be valued according to the STPIS customer valuations. That is, the TNSP with good reliability performance would be rewarded by its good performance being associated with more 'revenue' in forming the output weight, just as would be the case with any other output.

7) *Is reliability better included on the outside or the input side of economic benchmarking?*

8) *What is the best way of including reliability as an output?*

The revised short list

Economic Insights recommends that the following short list be considered for use as TNSP outputs in economic benchmarking studies:

- measured and smoothed non–coincident terminal maximum demands
- system capacity (taking account of both transformer and line/cable capacity)
- number of entry and exit points, possibly adjusted for voltage levels
- throughput (total or by broad user type or by location)
- number of unplanned outage events
- loss of supply event frequency
- aggregate unplanned outage duration, and
- number of protection system failure events.

9) *Have any important outputs been left off the short list?*

Operating environment factors – issues for discussion

We have expanded our short list of operating environment factors for possible inclusion to the following:

- weather
  - number of extreme cooling degree–days (above, say, 25° C)
  - number of extreme heating degree–days (below, say, 12° C)
  - number of extreme wind days with peak wind gusts over, say, 90 km/hour
- terrain
  - bushfire risk (number of days over 50 per cent of line length subject to equivalent of NSW severe or higher bushfire danger rating)
  - rural proportion (percentage of line length classified being as in a rural area)
  - vegetation encroachment (percentage of route line length requiring active vegetation management)
- network characteristics
  - route length of lines
  - proportion of energy dispatch from non–thermal generators
  - greatest distance from node having at least 30 per cent of generation capacity to node having at least 30 per cent of load.

In addition to seeking stakeholder feedback on this revised short list we also seek stakeholder input in developing a measure of the following:

- network density variable to reflect degree of meshing versus extension of network.

One possible indicator is MVA system capacity per route kilometre of line.

10) Have we included the main operating environment factors?

11) Do TNSPs face higher costs operating in rural areas compared to urban areas?

1 BACKGROUND

The Australian Energy Regulator (AER) has initiated a work stream on expenditure forecast assessment (EFA) guidelines for electricity distribution and transmission as part of its Better Regulation program responding to the Australian Energy Market Commission's recent rule changes for electricity network regulation (AEMC 2012a). The rule changes clarify the AER's powers to undertake benchmarking and add a new requirement for the AER to publish annual benchmarking reports on electricity network businesses.

The AER has indicated that economic benchmarking will be one of a suite of assessment techniques to be detailed in the EFA guideline. The AER is consulting extensively with network service providers in developing its approach to economic benchmarking. This includes conducting a series of workshops to seek feedback on the appropriate outputs, inputs and operating environment variables to be used in economic benchmarking and their specification, putting necessary data reporting mechanisms in place, and how economic benchmarking would be used in assessing NSPs' expenditure proposals.

The AER has engaged Economic Insights to assist with this consultation process. In March 2013 a series of workshops were conducted discussing what the appropriate outputs, inputs and operating environment factors would be for economic benchmarking used as part of building blocks determinations. Briefing notes were prepared for each of these workshops (Economics Insights 2013a,b,c).

The consultation process is now moving into its second phase discussing specific measurement and data issues associated with the outputs, operating environment factors and inputs for use in economic benchmarking. These briefing notes provide background material for the second workshop of the second phase (and the fifth overall) on measuring outputs and operating environment factors to be used for economic benchmarking of electricity TNSPs.

The second section of the briefing notes discusses a number of output quantity and price issues arising from the first phase discussions. These include:

- whether network capacity or peak demand should be included as an output
- how output weights should be derived
- how reliability should be included as an output, and
- whether throughput should be included as an output.

The third section lists the revised output short list based on discussions and feedback to date. It also lists the output data requirements for economic benchmarking of TNSPs and presents some preliminary output variable definitions. Finally, the fourth section discusses a number of operating environment factor considerations and presents a revised short list of key indicators.

2 TNSP OUTPUT QUANTITY AND PRICE ISSUES

The primary issue for discussion at the fifth workshop is whether the TNSP output data requirements to implement economic benchmarking listed in table 1 in section 3.2 are complete. That is, are there any variables missing from table 1 in section 3.2 that should be there? The table also lists preliminary variable definitions and gives an indication of whether the variable is currently collected in TNSP IDRs. We are interested in feedback on whether the definitions are appropriate for economic benchmarking and whether any definitions should be altered to ensure consistency across TNSPs.

Before presenting the data requirements table in section 3, in this section we discuss and provide further analysis on several issues raised in the second workshop.

2.1 Network capacity, peak demand and throughput

There was considerable discussion at the second workshop on how the output of a TNSP could be best represented and measured and whether it was more appropriate to include system capacity or peak demand as the primary functional output TNSPs supply. Grid Australia (2013, p.21) suggested the outputs of transmission network are best described as follows:

> 'Transmission networks provide capacity, to a level of reliability, in compliance with National Electricity Rule requirements, jurisdictional requirements and other regulatory obligations.'

It went on to note that the requirements on TNSPs under the NER include:

- requirements around stability, voltage unbalance, fault level tolerance and other aspects of the technical envelope of networks
- requirements relating to connections, such as the connection of new load and generation
- references throughout the Rules requiring functions to be performed in accordance with good electricity industry practice, and
- investment drivers considered under the Regulatory Investment Test – Transmission, which include both reliability and market benefits.

Economic Insights (2013b) noted that NSP representatives had previously likened an NSP's role to the provision of a road network. The road network operator has to make sure roads go to appropriate places and have sufficient capacity to meet peak demands but the road operator has little control over the volume of traffic on the road, either in total or at any particular time. The implication of this analogy is that it is then appropriate to measure the NSP's performance by the availability of its network and the condition in which it has maintained it rather than by the throughput of the network (ie the volume of traffic using the road, either in total or at a particular time).

Grid Australia (2013, p.21) noted that it 'agrees with the analogy in the Economic Insights paper that transmission networks provide outputs similar to roads, in the sense of capacity and entry and exit points'.

A criticism, however, of including system capacity as a functional output is that it does not distinguish between those TNSPs who have provided sufficient system capacity to meet forecast or actual peak demands and other requirements and those who have provided excess capacity. Further, its use may create an incentive to overestimate future capacity needs and thus to provide excess capacity in the future. There was some discussion at the workshop of whether the use of peak demand was a better measure of the load a TNSP has to be able to accommodate and whether it was an appropriate proxy for required system capacity. Economic Insights (2013b, p.11) noted that system peak demand tends to be somewhat volatile over time due to the influence of variable climatic conditions and other factors outside network control. If peak demand were to be included as an output, it may be more appropriate to include either a smoothed series or a 'ratcheted' variable that reduced the effect of such volatility. Given the prospect of decreases in energy usage and peak demands, a smoothed and possibly weather corrected series is likely to be more appropriate than a ratcheted series. For similar reasons, a number of NSP representatives at the first workshop suggested that the forecast peak demand series that the NSP's previous price determination had been based on was a more appropriate peak demand series than actual peak demand.

Grid Australia (2013, p.22) disagreed with the use of both peak demand and throughput as follows:

> 'Neither energy nor peak demand are outputs of a transmission network, or (for the most part) within the control of TNSPs. Rather, they are determined through the interaction between generators and consumers (via retailers) determining supply and demand in the electricity market. Therefore, Grid Australia does not support their inclusion as outputs for benchmarking purposes.'

Economic Insights agrees that actual peak demand is a poor indicator of the load capacity a TNSP is required to provide and, due to its volatility, using actual peak demand would likely lead to inappropriate volatility in efficiency results. A high degree of smoothing of actual or weather corrected peak demand would overcome the volatility problem while also giving a more accurate indication of required capacity. Ideally the probability of exceedance would also be taken into account in forming the smoothed series.

While forecast non–coincident maximum demand from the most recent regulatory determination may provide an indication of the loads the TNSP was expected to be able to meet and which were built into the building blocks revenue requirement, it also has some limitations. Once the building blocks allowance is set, TNSPs are expected to respond to the incentive to be efficient and this may include responding to lower than forecast demand and/or revised forecast demand. Furthermore, using forecast peak demand from the determination may provide an incentive for TNSPs to over–inflate forecasts in future reviews.

Maximum demands will provide an indication of the transformer capacity required by the TNSP, all else equal. They do not distinguish between the amount of lines required by two TNSPs who may have similar forecast maximum demands but one of which transmits power between generation centres and load centres in close proximity and the other of which transmits between dispersed generation and load centres. One would expect the TNSP with more dispersed generation and load centres to require a higher length of line to deliver the same forecast maximum demand. This will require that TNSP to use more inputs to deliver the same forecast maximum demand and, hence, make it appear less efficient unless it either gets some credit on the output side for its greater line length requirement or, alternatively, distance between generation and load centres is included as an operating environment factor.

Including system capacity as an output provides one means of recognising lines as well as transformer requirements. For example, Economic Insights (2009) included a broader measure of electricity distribution system capacity that recognised the role of lines as well as transformers (for DNSPs). This was the simple product of the installed distribution transformer kVA capacity of the last level of transformation to the utilisation voltage and the totalled mains circuit length (inclusive of all voltages but excluding services, streetlighting and communications lengths). The advantage of including such a measure is that it recognises the key dimensions of overall effective system capacity. It also reflects actual capacity available rather than a forecast capacity requirement that may or may not be met. And it does not have the volatility beyond the TNSP's control which is a problem with the actual peak demand measure. A comparable simple measure could be readily implemented for TNSPs.

Grid Australia (2013, pp.22–3) supported the use of system capacity as a TNSP output but observed the following:

> 'System capacity is an appropriate output variable, as it reflects the service provided by TNSPs.
>
> 'The capacity output should include transformer capacity as well as line and cable capacity. A simple product based on bulk supply point capacity is unlikely to be a suitable summary measure, as it does not take into account inter–regional and intra–regional power transfers that utilise the transmission network.'

Economic Insights recognises that the simple product of TNSP line length and the sum of terminal point and directly–connected end–user transformer capacity is a relatively basic system capacity measure which may not fully capture the complexities of TNSP functions. However, we are of the view that it represents a useful starting point for subsequently developing more sophisticated measures of system capacity for use in economic benchmarking of TNSPs.

There are arguments for and against including system capacity versus smoothed maximum demand as a functional output. On balance, we are of the view that both measures warrant further investigation and sensitivity analysis should be undertaken. System capacity taking in both line length and transformer capacity is likely to be the best option in the short term as it requires a minimal number of observations to implement. Once sufficient data observations become available inclusion of smoothed maximum demand should be investigated, along with more sophisticated measures of TNSP system capacity.

Most workshop participants noted that changes in throughput are not a significant cost driver for TNSPs and, hence, throughput should not be considered a significant output. However, others noted that because throughput is what customers see directly and pay for, it should not be ignored. We also note that throughput has been included as an output in nearly all previous network economic benchmarking studies (see AER 2012a, p.77).

Given that throughput is what customers consume directly, the relative robustness of throughput data and its inclusion in nearly all previous economic benchmarking studies, we recommend that throughput still be considered for inclusion as an output, although it is likely to receive a relatively small weight in light of its small impact on network costs.

2.2 Calculating output weights

There was general agreement at the second workshop and in submissions on AER (2012a) that a functional outputs approach was more appropriate than a billed outputs approach for use in economic benchmarking used in a building blocks context. This is because some NSPs impose charges on energy throughput even though changes in aggregate energy throughput usually have little impact on the costs they face and dimensions that customers may value highly such as reliability are not explicitly charged for at all (although, in the case of TNSPs, the drivers may enter as components of the TNSPs' service quality incentive scheme). As a result, observed revenue shares will be of limited usefulness (in a building blocks context) in forming weights for those economic benchmarking techniques that aggregate output quantities into a measure of total output or for assessing the reasonableness of shadow weights for those techniques that allocate shadow weights in forming an efficiency measure.

Grid Australia (2013, p.21) noted:

> 'the setting of revenues and the conversion of this revenue into tariffs are specified in separate parts of Chapter 6A in the Rules, such that the actual form and structure of tariffs charged to customers is not a direct consideration in the setting of revenues. In that regard, while it is important to consider the price impact on customers that might derive from a revenue allowance, the form and structure of tariffs borne by customers are not outputs that feed directly into setting this amount.'

Rather, it will be necessary to form output weights based on the weights implicitly used in building blocks determinations. These are generally taken to be cost–reflective output weights.

There are three broad options available to form cost–reflective output weights for use in economic benchmarking:

- estimate the weights from an econometric cost function;
- use weights from previous cost function studies from a broadly comparable sample, or
- obtain estimates of the relative cost of producing each of the specified outputs from the TNSPs themselves.

We examine each of these options in turn.

Estimating cost function–based output weights

Most economic benchmarking studies using a functional outputs approach have formed estimates of cost–reflective output weights from econometric cost function models. This is done by using the relative shares of output cost elasticities in the sum of those elasticities because the cost elasticity shares reflect the cost of providing relevant output components.

The sophistication and complexity of the cost function that can be estimated depends on the extent of data and number of observations available. Very simple cost functions can be estimated with only a limited number of observations. For example, Lawrence (2000) estimated a simple log–linear cost function using 10 cross sectional DNSP observations which included a constant, three output quantities and an input price index.

Lawrence (2003) had access to more observations and was able to estimate a multi–output Leontief cost function using data for 28 DNSPs over 7 years. The cost function included the three outputs of throughput, system line capacity and connections. It included four inputs: operating expenses, overhead lines, underground lines and transformers. This simple model produced output cost share estimates for the three outputs included of 22 per cent for throughput, 32 per cent for network line capacity and 46 per cent for connections.

This functional form essentially assumes that DNSPs use inputs in fixed proportions for each output and is given by:

(1) $$C(y^t, w^t, t) = \sum_{i=1}^{M} w_i^t \left[\sum_{j=1}^{N} (a_{ij})^2 y_j^t (1+b_i t)\right]$$

where there are M inputs and N outputs, w_i is an input price, y_j is an output and t is a time trend representing technological change. The input/output coefficients a_{ij} are squared to ensure the non–negativity requirement is satisfied, ie increasing the quantity of any output cannot be achieved by reducing an input quantity. This requires the use of non–linear regression methods. To conserve degrees of freedom a common rate of technological change for each input across the three outputs was imposed but this can be either positive or negative.

The estimating equations were the M input demand equations:

(2) $$x_i^t = \sum_{j=1}^{N} (a_{ij})^2 y_j^t (1+b_i t)$$

where the i's represent the M inputs, the j's the N outputs and t is a time trend representing the seven years, 1996 to 2003.

The input demand equations were estimated separately for each of the 28 DNSPs using the non–linear regression facility in Shazam (White 1997) and data for the years 1996 to 2003. Given the limited number of observations and the absence of cross equation restrictions, each input demand equation was estimated separately.

The output cost shares for each output and each observation were then derived as follows:

(3) $$h_j^t = \left\{\sum_{i=1}^{M} w_i^t [(a_{ij})^2 y_j^t (1+b_i t)]\right\} / \left\{\sum_{i=1}^{M} w_i^t \left[\sum_{j=1}^{N} (a_{ij})^2 y_j^t (1+b_i t)\right]\right\}.$$

A weighted average of the estimated output cost shares for each observation was then used to form an overall estimated output cost share where the weight for each observation, b, is given by:

(4) $$s_b^t = C(b, y_b^t, w_b^t, t) / \sum_{b,t} C(b, y_b^t, w_b^t, t).$$

Lawrence (2007) estimated a similar cost function model for the three Victorian gas distribution businesses using data for the years 1998 to 2006. For the equivalent three output components in gas distribution this produced an output cost share for throughput of 13 per cent, for customers of 49 per cent and for system capacity of 38 per cent. For a two output specification covering throughput and customer numbers it produced an output cost share for throughput of 25 per cent and for customers of 75 per cent.

As more observations become available then more complex cost functions can be estimated including flexible cost functions that include second order terms allowing second–order approximations instead of the first–order approximations of the simpler cost functions described above. The translog cost function is the most commonly used flexible cost function.

Economic Insights (2012a) provides an example of a simple second order operating cost function (as opposed to total cost function) for gas distribution businesses as follows:

$$\begin{aligned} (5) \quad & \ln C_{OM} = b_0 + b_D \ln D + b_C \ln C + \ln W_{OM} + 0.5 b_{DD} \ln D \ln D + 0.5 b_{CC} \ln C \ln C \\ & + b_K \ln K + b_t t \end{aligned}$$

where C_{OM} is operating cost, D is deliveries (or throughput), C is customer numbers, W_{OM} is the opex input price, K is pipeline length and t is a time trend. Note that the opex input price enters the operating cost function with a coefficient of one in this instance to ensure homogeneity of degree one in prices and pipeline length is included as a proxy for fixed capital inputs. Second order terms are included for outputs. In this instance the key operating environment characteristics of customer density and energy density enter through the inclusion of the two output variables and the capital quantity variable. The density drivers cannot be included as separate terms in addition to their constituent components due to multicollinearity.

The data used in this study were actual data for 11 gas distribution businesses covering actual data from 1999 onwards (where available) and forecast data from the latest regulatory determinations (where available) out to as far as 2017. In all, 144 observations were available. This study produced estimated output *operating* cost shares of 45 per cent for throughput and 55 per cent for customer numbers.

The sample of economic benchmarking studies listed above have used increasingly more sophisticated cost functions to estimate cost–reflective output weights as more observations have become available. Provided a relatively small number of outputs are included, the log linear cost function can be estimated on cross sectional data while the Leontief cost function can be estimated with a relatively small number of observations for each of the included NSPs.

Using weights from previous cost function studies

Another common approach used in economic benchmarking studies has been to draw on the output weights obtained in earlier comparable economic benchmarking studies. For example, later Australian DNSP economic benchmarking in Lawrence (2005) and later New Zealand DNSP economic benchmarking in Economic Insights (2009) both used the cost–reflective output weights derived in Lawrence (2003). Similarly, Economic Insights (2012a) economic benchmarking of the Victorian gas distribution businesses used the cost–reflective gas distribution output weights estimated in Lawrence (2007).

While drawing on the results of previous cost function studies is reasonable where the earlier studies were of industries directly comparable to the one at hand, it has the potential limitation of restricting the choice of outputs to the same components as used previously. Another limitation of this option for economic benchmarking of TNSPs is that there are relatively few earlier studies of TNSP efficiency to draw on.

Obtaining relative cost estimates directly from TNSPs

While it is desirable to estimate the output weights to be used in economic benchmarking by objective and reproducible independent means, another alternative is to request the TNSPs to provide estimates of how their total costs should be allocated across the included output components. This process could also provide a useful ‘sanity check’ for output weights estimated by other means.

It would be necessary for the AER to provide guidance on how TNSP costs should be allocated across the nominated output components. The approach adopted should be consistent with that being developed in detail as part of the category analysis workstream.

Two broad methods of cost allocation that are commonly used in other industries are the fully distributed costs method and activity based cost accounting. The fully distributed cost method of cost allocation allocates the total costs incurred by an entity across all the nominated outputs. Under this approach costs are normally categorised as directly attributable costs and shared costs. Directly attributable costs are those that can be directly identified with or attributed to a particular nominated output. A direct relationship can sometimes be established based on functional responsibility. However, the main principle that is used to identify directly attributable costs is cost causality, ie directly attributable costs include all those costs that are causally related to a particular nominated output or at least clearly causally related.

The shared costs are those that are not clearly causally related to the particular nominated output. The fully distributed cost method allocates shared cost by an appropriate method, that is normally chosen on the basis of being the best proxy of cost causality, even though conceptually a direct cost causation relationship does not exist. The three most popular allocators are relative outputs, relative directly attributable costs and relative revenues.

Although a well defined cost causality relationship can often not be established for the chosen indicator, there is a sense in which the supply of nominated output entails cost causation. That is, because the same shared costs may be used for a variety of purposes so that there is an opportunity cost in supplying the service for one nominated output rather than another.

However, because the allocation of shared costs is not unique, the resulting output weights may not bear a close resemblance to marginal costs.

Activity based cost accounting systems are a further refinement of the fully distributed cost approach. Such systems are effectively a systematic and detailed approach for establishing causal links between costs and nominated outputs and hence implementing the fully distributed cost methodology. The approach entails representing the business as a series of activities, each of which consumes resources and therefore generates costs.

The stages in an activity based costing system are as follows:

- costs are estimated for each discrete activity that can be identified within the business with a number of cost activity pools formed. Activities can be thought of as intermediate stages within the production process which contribute to one of more end products or services but do not constitute an end product or service in their own right
- costs of specific activity pools are then allocated to a nominated output depending on the number of 'activity units' consumed by the nominated output, and
- the total cost of the nominated output is the sum of the costs attributed from each cost activity pool.

Ideally, an activity is a task or group of tasks for which a single cost cause (or 'driver') can be established without incurring too many transactions costs. The implementation of the concept entails focusing on the purpose of the expenditure and identifying indicators that reflect cost causation. However, activity based cost accounting cannot be used where cost causation cannot be established. Where cost causation cannot be established, appropriate allocators are selected as in the fully distributed cost methodology described above. The main advantage of activity based cost accounting is in the transparency of the cost allocation process.

As noted above, the exact approach adopted should be consistent with that being developed in detail as part of the category analysis workstream but is likely to be a type of fully distributed costs model. The amount and allocation of shared costs would also need to be disclosed.

Once a cost allocation method is finalised, we believe it would be appropriate for the AER to implement requirements similar to those in the AER (2008a) cost allocation guidelines. This would require a TNSP's detailed principles and policies for attributing costs directly to, or allocating costs between nominated outputs to be sufficiently detailed to enable:

1) the AER to replicate the reported outcomes through the application of those principles and policies, and
2) the TNSP to demonstrate that it is meeting the specified requirements.

This means that a TNSP would be required to include information on the following matters to enable the AER to replicate its reported outcomes:

1) for directly attributable costs:
    a. the nature of each cost item
    b. the nominated output to which the cost item is to be directly attributed
    c. the characteristics of the cost item that associate it uniquely with a particular nominated output in order to make it a directly attributable cost, and
    d. how and where records will be maintained to enable the basis of attribution to be audited or otherwise verified by a third party, including the AER.
2) for shared costs:

a. the nature of each cost item

b. the nominated outputs between which each cost item is to be allocated

c. the nature of the allocator, or allocators, to be used for allocating each cost item

d. the reasons for selecting the allocator, or allocators, for each cost item and an explanation of why it is the most appropriate available allocator, or set of allocators, for the cost item

e. whether the numeric quantity or percentage of the allocator, or allocators, to be applied for each cost item could be expected to:

    i. remain unchanged over the regulatory control period, or

    ii. change from time to time throughout the regulatory control period.

f. how and where records will be maintained to enable the allocation to be audited or otherwise verified by a third party, including the AER.

A TNSP would not be allowed to allocate the same cost more than once which means that:

- the same cost may not be treated as both a direct cost and a shared cost
- a direct cost may only be attributed once to a single nominated output, and
- a shared cost may only be allocated once between nominated outputs.

The AER would likely need to consult with TNSPs in advance of collecting these costs estimates to develop consistent, robust definitions of costs and to ensure as consistent a treatment as possible across TNSPs.

2.3 Reliability

There was general agreement amongst workshop participants that reliability should, if possible, be included as a TNSP output.

Grid Australia (2013, p.23) noted:

> 'Grid Australia strongly supports the inclusion of reliability as a key output as it is a material driver of expenditure on transmission networks. Grid Australia acknowledges the issues associated with developing a measure for reliability and would be willing to assist in further consideration of this.'

In addition, reliability should be included to ensure TNSPs do not improve their measured efficiency performance by neglecting network maintenance and other initiatives important to maintaining and, where appropriate, further improving reliability levels.

In this section we review three issues raised at the second workshop:

- what are the appropriate reliability measures for TNSP benchmarking?
- how can reliability indexes be included as output quantities? and
- what weight should reliability outputs get?

Appropriate reliability measures for economic benchmarking

There was some concern expressed at the second workshop that basing the reliability output heavily on the current STPIS parameters may not be appropriate as they are geared to time–series rather than cross–sectional comparisons. Grid Australia (2013, p.23) noted:

> 'the STPIS was specifically designed to provide incentives for TNSPs to continuously improve or maintain performance against their own historical performance in relation to operational measures (rather than capital investment). The parameters are therefore well defined for providing incentives to each TNSP but are not suited to comparison between TNSPs. For example, each TNSP has different thresholds for loss of supply events, in order to set meaningful targets given the different inherent performance characteristics of each network. Also, the market impact component counts dispatch intervals with a market impact of outages, but does not seek to normalise this for factors outside a TNSP's control such as market participant behaviour ...'

Economic Insights agrees that using the market impact component of the STPIS for economic benchmarking may be problematic since it measures the change in a price level which will be influenced by a range of factors, not all of which are under TNSP control, and which will vary according to time and location. We therefore propose to remove the market impact measure from our short list of outputs.

We note that the definitions of loss of supply events do vary across TNSPs according to their inherent performance characteristics, although the major differences are between what constitutes a 'small' event and a 'large' event. This means the loss of supply event indicator already includes some adjustment for operating environment differences. We consider use of the variable to be a worthwhile starting point for economic benchmarking purposes pending further refinement and co–ordination with included operating environment factors.

Economic Insights (2013b) noted that the loss of supply frequency and average outage duration indicators both reflect the TNSP's success in meeting and managing expected demand and maintaining the quality, reliability and security of both transmission services and the transmission system. They also reflect the quality of the service provided to network users and the cost of improving this dimension of performance can be quite significant.

The loss of supply event frequency indicator measures the number of unplanned outages when there has been a loss of supply. This is further broken down into small events and large events. It is designed to encourage TNSPs to reduce response times to small and medium customer interruptions and to reduce the number of interruptions to large customers.

The average outage duration measures the average length of unplanned outages where a loss of supply to customers has occurred. It is intended to focus the TNSP on those unplanned outages with the greatest impact on customers. As was the case with DNSP reliability measures, we propose to include total outage duration as the output rather than average outage duration as normalisation of the indicator is not required for economic benchmarking.

Economic Insights (2013b, p.13) also noted that average circuit outage rate and the proper operation of equipment measures were important indicators of 'secondary deliverables'. That is, they provide useful information on the TNSP's ability to meet and manage expected demand and maintain the quality, reliability and security of both transmission services and the transmission system. However, they are not a service directly provided to end–customers but rather lead indicators of potential unreliability.

Grid Australia (2013, p.22) stated the following with regard to secondary deliverables:

> 'Outputs described by Economic Insights as 'secondary deliverables', such as system security, are required under the National Electricity Rules and to uphold the National Electricity Objective, and as such should be included as outputs.'

We agree that, in the case of transmission, key secondary deliverables warrant some recognition as outputs for economic benchmarking purposes. We therefore propose to promote the average circuit outage rate and the proper operation of equipment measures to the short list of TNSP outputs.

The average circuit outage rate measures the actual number of times defined transmission circuits are unavailable due to unplanned (fault/forced) outages divided by the total number of defined (lines/transformer/reactive) circuits. Again, for economic benchmarking purposes, the total number of unplanned outage events will be used rather than the average per circuit.

The proper operation of equipment sub–component measures the number of incidents where a protection or control system has failed or where there has been incorrect operational isolation of equipment during maintenance. It is intended to be a lead indicator of reliability.

Including reliability as an output quantity

Outputs in efficiency studies have generally been measured in such a way that an increase in the measured quantity of an output represents more of the output and, hence, a desired result. But both the frequency and duration of outages are measured by indexes where a decrease in the value of the index represents an improvement in service quality. It would be necessary to either include the indexes as undesirable or 'bad' outputs (ie a decrease in the measure represents an increase in overall output) or else to convert them to measures where an increase in the converted measure represents an increase in output. One of the ways of addressing this tried initially was to invert the reliability measures to produce an increase in the measure equating to an increase in output. However, this generally led to a non–linear transformation which produced distorted results. Another option tried was to look at the minutes the system was on–supply rather than the minutes it is off–supply. However, since most systems are interrupted for a relatively small number of minutes each year, using the number of minutes the system is uninterrupted effectively produces a constant variable that is of limited use.

The key reliability indexes of SAIDI and SAIFI have been the main reliability measures used in economic benchmarking studies to date (which have mainly related to distribution). They have mainly been included in econometric models where the need for more output to be represented by an increase in the variable is less of an issue. Some econometric studies have transformed the indexes into a more convenient form by multiplying them by total customer numbers (eg Coelli et al 2010). This produces measures of total customer minutes lost and total customer interruptions.

Some economic benchmarking studies have included reliability as an input rather an output in recognition of a DNSP’s ability to substitute between using opex and capital, on the one hand, and reduced reliability and associated penalties on the other (see Coelli, et al 2008).

It is desirable to have a way of including standard reliability measures as outputs in economic benchmarking studies, including index–based methods which are the most likely methods to be able to be implemented initially. We propose two alternative means of doing this be further investigated.

The first method involves including total outage minutes or total number of outages as an undesirable or ‘bad’ output. This involves allocating a negative price to the measure and, hence, a negative weight in forming the total output measure. By giving the reliability measure a negative weight, it is then treated as a ‘bad’ rather than a ‘good’ output and reducing the value of the measure (ie improving reliability) will be consistent with increasing overall output. This approach follows the method developed by Pittman (1983) for including outputs of industrial pollution in studies of manufacturing productivity performance. It can be readily implemented using standard indexing methods and computer programs. A variant of this approach was adopted in Lawrence (2000) where interruption indexes were included as an undesirable output in an economic benchmarking study of 10 Australian DNSPs. How this undesirable output was weighted will be discussed further below.

The second method we believe warrants further investigation is to form a benchmark level of the maximum level of acceptable overall outages and subtract the actual level of outages from this benchmark level. This subtraction would produce a variable with the standard output characteristics where a higher value represented more of the output. That is, a low value of outage duration representing higher reliability when subtracted from the benchmark level would produce a higher output quantity than would a high value of outage duration representing lower reliability when subtracted from the benchmark. The problem with this approach is that there is likely to be a degree of arbitrariness in setting the target benchmark level of worst acceptable reliability. This could be related to jurisdictional standards but would need to be a common value across similar included TNSPs for economic benchmarking purposes. It would need to be set sufficiently high that it exceeded the worst observed performance to ensure the result of the subtraction was positive in all cases.

What weight should reliability outputs get?

End–customers normally prefer better quality service to inferior quality service and are prepared to pay a premium for better service. However, the size of the premium they are prepared to pay will depend on their individual preferences and the amount of quality involved. End–consumers typically exhibit reduced marginal willingness to pay as the amount of quality increases. That is, as they attain higher quality levels, end–consumers value additional improvements in quality less so they are prepared to pay less to go from a very good service to an excellent service than they were to go from a poor service to a mediocre service.

TNSPs, on the other hand, face increasing marginal costs of improving quality. For instance, improved maintenance practices and some basic strengthening of the network may improve service quality from poor to medium at modest cost. However, to go from medium to high service quality levels is likely to require major capital expenditure to strengthen and possibly duplicate parts of the network and make greater use of undergrounding which will come at a much higher cost.

The optimal level of service quality will occur where the end–consumer's marginal willingness to pay is equal to the TNSP's marginal cost to improve service quality. For service quality levels below the optimum, end–consumers value a small increase in service quality by more than it costs the TNSP to produce it while for service quality levels higher than the optimum level, it costs the TNSP more to produce a small increase in quality than end–consumers value it.

For economic benchmarking purposes we need to decide whether reliability outputs should be valued according to the cost to the TNSP of improving reliability or according to the value placed on reliability by the end–consumer. The methods outlined in the previous section can be used to obtain estimates of the costs to the TNSP of reliability outputs. There are also a range of estimates of the value end–consumers place on reliability, the most recent of which is AEMC (2012b) (although this is an upper bound as it relates to outages at the most inconvenient time of the day). The DNSP STPIS service quality incentive scheme operated by the AER also contains incentive rates based on end–consumers' valuation of reliability performance (AER 2008b) and, for consistency, is likely to the best source of estimates of customer valuation of reliability for economic benchmarking purposes.

A good case can be made that reliability outputs should be valued according to the end–customer's valuation rather than the TNSP's costs of improving reliability. Given that end–customers will value successive improvements in reliability successively less highly whereas they will cost TNSPs increasingly more to supply, it is important that TNSPs not be given an incentive to keep increasing reliability beyond the point where their marginal costs exceed end–customers' marginal valuations of additional reliability.

Some European regulators have adopted a broadly similar approach although the cost of outages has been included as an additional input rather than reliability being explicitly included as an output. For example, the Finnish regulator includes the 'disadvantage to the customer caused by electricity supply outages' while the Norwegian regulator includes the cost of outages based on customer willingness to pay derived from a reference power price (WIK–Consult 2011).

In an economic benchmarking study of DNSPs, Lawrence (2000) also valued the (undesirable) outage output using an estimate of end–customer inconvenience from outages. Lawrence (2000) allocated a directly calculated value to the reliability variable based on end–customer valuation of inconvenience while using the cost elasticity approach to allocate weights to the other three output components based on the DNSPs' costs of supplying the other outputs (throughput, customer numbers and system capacity).

For the reliability variable the value of minutes off supply was calculated in Lawrence (2000) by deriving the average kilowatt hours the DNSP supplies for every minute it is supplying electricity and multiplying this by 8.7 cents (the then average price paid by consumers for electricity) and also by a penalty factor of 100 (reflecting the much higher inconvenience cost of power supplies interrupted) by the number of minutes off supply. The interruptions index then received a negative weight based on the estimated cost of interruptions to customers. It should be noted that the choice of the 100 times penalty factor was somewhat arbitrary but the study predated the major studies of end–consumer valuation of reliability in Australia. If this process were to be adopted now, the end–customer valuations of reliability included in the distribution STPIS (AER 2008b) could be used instead. On average, this procedure adopted at the time involved a weight of around 8 per cent of DNSP revenue being allocated to the reliability output across the 10 included DNSPs.

As a practical way forward for economic benchmarking of TNSPs, we recommend adopting the distribution STPIS valuations of end–customer outages (AER 2008b). For the first approach of Lawrence (2000) of including interruptions as an undesirable output following the method developed by Pittman (1983), the value of customer outages would enter as the negative weight applied to TNSP interruptions. This process would require an estimate to be made of the number of end–customers that would be affected by an outage for the TNSP.

For the second approach above of including the difference between observed reliability and a benchmark worst acceptable reliability performance, the transformed reliability output would simply be valued according to the distribution STPIS end–customer valuations. Again, this process would require an estimate to be made of the number of end–customers that would be affected by an outage for the TNSP. It would lead to a TNSP with good reliability performance receiving a higher weight for that good performance than a TNSP with bad performance would receive for its performance. That is, the TNSP with good reliability performance would be rewarded by its good performance being associated with more 'revenue' in forming the output weight, just as would be the case with any other output.

3 THE REVISED OUTPUT SHORT LIST AND DATA REQUIREMENTS

3.1 The revised short list

Based on the discussion in section 2, Economic Insights recommends that the following short list be considered for use as TNSP outputs in economic benchmarking studies:

- measured and smoothed non–coincident terminal maximum demands
- system capacity (taking account of both transformer and line/cable capacity)
- number of entry and exit points, possibly adjusted for voltage levels
- throughput (total or by broad user type or by location)
- number of unplanned outage events
- loss of supply event frequency
- aggregate unplanned outage duration, and
- number of protection system failure events.

While a case can be made for the inclusion of additional output components, most economic benchmarking techniques are limited on practical implementation grounds to a relatively small number of outputs and so the most important ones have to be prioritised for inclusion. Consequently, most studies would use a subset of the output variables on the short list. System capacity and non–coincident maximum demand would generally be used as alternatives rather than both being included as outputs.

3.2 Data requirements

The TNSP output data requirements to implement economic benchmarking are listed in table 1 along with preliminary variable definitions and an indication of whether the variable is currently collected in TNSP Information Disclosure Requirements (IDRs). The variables listed are required to support the short listed outputs, possible alternative specifications which may be developed and a range of anticipated sensitivity analyses.

Stakeholders views are sought on whether the definitions proposed are appropriate for economic benchmarking purposes and whether any of the definitions should be altered to ensure consistency across TNSPs.

Table 1: **Electricity TNSP output variables and preliminary definitions**

Variable	Unit	Definition of variable	Data in IDR?
TUOS Revenue for Prescribed Transmission Services	$m	Annual Revenue earned from the provision of Prescribed Transmission Services only. Annual Revenue for the relevant year – in $ of the year.	Network charges disclosed
Revenue Grouping by chargeable quantity		Grouping to match tariff charging arrangements – ie not all TNSPs may have charges for all quantities	May be some segregation in sheet PTS Rev Analysis
From Fixed Customer (Exit Point) Charges	$m		
From Variable Customer (Exit Point) Charges	$m		
From Fixed Generator (Entry Point) Charges	$m		
From Variable Generator (Entry Point) Charges	$m		
From Fixed Energy Usage Charges (Charge per day basis)	$m		
From Variable Energy Usage charges (Charge per kWh basis)	$m		
From Energy based Common Service and General Charges	$m	Where Common Service and General Charges are recovered on an energy basis	
From Fixed Demand based Usage Charges	$m	Where charges are made based on a “nominated / agreed” demand basis	
From Variable Demand based Usage Charges	$m	Where charges are made based on a “measured / actual” demand basis	
Revenue Grouping by type of connected equipment			
From Other connected transmission networks	$m		
From Distribution networks	$m		
From Directly connected end–users	$m		
From Generators	$m		
Total	$m		
Revenue/penalties from incentive schemes	$m		

Variable	Unit	Definition of variable	Data in IDR?
ENERGY DELIVERY		The amount of electricity transported out of the TNSP's network in the relevant regulatory year (measured in GWh). Metered at the downstream charging location rather than the import location to the TNSP	May be some segregation in sheet PTS Rev Analysis
Total Energy delivered	GWh		
Energy Grouping by Downstream Connection type			
To Other connected transmission networks	GWh		
To Distribution networks	GWh		
To Directly connected end–users (please specify voltages)	GWh		
Total energy delivered	GWh	Energy measured at the output location or interconnector receiving end	
SYSTEM CAPACITY			
Transmission System Capacities			
O/H Line circuit length by voltage level – km and typical / averaged MVA capacity of circuit at each voltage		Calculated as circuit length (measured in kilometres) of lines in service (the total length of lines including interconnectors, backbone and spurs). A double circuit line counts as two lines. Indicate estimated typical or weighted average circuit capacity for the overall voltage class under normal circumstances to be used for MVA x km capability product – limit may be thermal, voltage drop or other limitation as relevant	Physical data generally not included
500 kV	km & MVA		
330 kV	km & MVA		
275 kV	km & MVA		

Variable	Unit	Definition of variable	Data in IDR?
220 kV	km & MVA		
132 kV	km & MVA		
(Other transmission voltages)	km & MVA	Alternatively, “legacy voltages” or “alternative voltages” eg 110 kV may be captured into the nearest relevant voltage currently in use.	
Other (please specify)	km & MVA		
Total overhead circuit kilometres	km		
U/G Cable circuit length by voltage level – km and typical / averaged MVA capacity of circuit at each voltage		Similarly to OH	Physical data generally not included
500 kV	km & MVA		
330 kV	km & MVA		
275 kV	km & MVA		
220 kV	km & MVA		
132 kV	km & MVA		
(Other transmission voltages)	km & MVA	Alternatively, “legacy voltages” or “alternative voltages” eg 110 kV may be captured into the nearest relevant voltage currently in use.	
Other (please specify)	km & MVA		
Total underground circuit kilometres	km		

Variable	Unit	Definition of variable	Data in IDR?
Installed transmission system transformer capacity	MVA	Transformer capacity involved in transformation level indicated below. Give summation of normal assigned continuous capacity / rating (with forced cooling etc if relevant). Include only energised transformers, not cold spare capacity. Include capacity of tertiary windings etc as relevant. Assigned rating may be nameplate rating, or rating determined from results of temperature rise calculations from testing. Do not include step-up transformers at generation connection location	Physical data generally not included
Transmission substations (eg 500 kV to 330 kV)	MVA	Transformer capacity at intermediate locations for transmission service function	
Terminal points to DNSP systems	MVA	Transformer capacity at connection point to DNSP	
Transformer capacity for directly connected end–users owned by the TNSP	MVA	Transformer capacity at connection point to directly connected end user where the capacity is owned by the TNSP	
Transformer capacity for directly connected end–users owned by the end–user	MVA	Transformer capacity at connection point to directly connected end user where the capacity is owned by the directly connected end user. Alternatively give summation of non-coincident individual maximum demands of directly connected end users whenever they occur (ie the summation of a single annual MD for each customer) as a proxy for capacity within the end user's installation.	
Other (please specify)	MVA		
System Demand	MW and MVA	As measured at the downstream / output connection locations	Physical data generally not included
Transmission System coincident maximum demand	MW and MVA	Raw coincident transmission system maximum demand without adjustment for weather etc	

Variable	Unit	Definition of variable	Data in IDR?
Transmission System non-coincident summated maximum demand	MW and MVA	Summation of actual raw demands at the TNSP downstream connection and supply locations at the time when this summation is greatest ie no weather normalisation etc	
Transmission system planned capacity on 50 % POE basis	MW and MVA	Capacity indicated or required at time of relevant load forecasting on 50% probability of exceedance basis	
Transmission system planned capacity on 10 % POE basis	MW and MVA	Capacity indicated or required at time of relevant load forecasting on 10% probability of exceedance basis	
Transmission system achieved capacity	MW and MVA	Capacity available in response to planned capacity requirements measured on similar basis	
PERFORMANCE TO STPIS COMPONENTS		Definitions etc as specified in the December 2012 Electricity transmission network service providers Service target performance incentive scheme documents.	Service Standards performance has been sought, but new scheme data differs
1 - Service Component			
Service Parameter 1 – Average Circuit outage rate		Note, in particular, “outage” means “loss of connection” rather than loss of supply by a connected system or customer. To allow summation into an overall Average Circuit outage rate, both numerator (No. of Events with defined circuits unavailable per annum) and denominator (Total No. of defined circuits) are needed as well as the calculated percentage rate for each item.	
Lines outage rate - fault	percent		
Number of Lines fault outages	number		
Number of defined Lines	number	As used to calculate the outage rate above	
Transformers outage rate - fault	percent		
Number of Transformer fault outages	number		
Number of defined Transformers	number	As used to calculate the outage rate above	

Variable	Unit	Definition of variable	Data in IDR?
Reactive plant outage rate - fault	percent		
Number of Reactive plant fault outages	number		
Number of defined Reactive plant	number	As used to calculate the outage rate above	
Lines outage rate – forced outage	percent		
Number of Lines forced outages	number		
Transformer outage rate – forced outage	percent		
Number of Transformers forced outages	number		
Reactive plant outage rate – forced outage	percent		
Number of Reactive plant forced outages	number		
Service Parameter 2 – Loss of supply event frequency – number in ranges specified	number	Values for x and y are specified for individual TNSPs in the STPIS documents	
Number of events greater than x system minutes per annum	number		
Number of events greater than y system minutes per annum	number		
Service Parameter 3 – Average outage duration			
Average outage duration	minutes		
System Parameter 4 – Proper operation of equipment – number of failure events			
Failure of protection system	number		
Material failure of Supervisory Control and Data Acquisition (SCADA) system	number		
Incorrect operational isolation of primary or secondary equipment	number		
2 - Market Impact Component			
Market Impact Parameter	Number of dispatch intervals	Definition etc as specified in the December 2012 Electricity transmission network service providers Service target performance incentive scheme documents.	
3 - Network Capability Component		Not relevant for economic benchmarking of network performance	

Variable	Unit	Definition of variable	Data in IDR?
Unsupplied system minutes	minutes	The amount of energy (MWh) not supplied to consumers divided by the maximum demand (MW) and multiplied by 60 to bring it to minutes	Published in AEMC Market Performance Review
System losses	percent	Losses as percentage of Energy input to transmission system network	

4 OPERATING ENVIRONMENT FACTORS

There was general agreement at the workshop that it is important to allow for a range of key operating environment factors, to the extent possible, when making efficiency comparisons across TNSPs. Economic Insights (2013b) suggested inclusion of climatic effects, terrain and length and capacity measures on the short list of operating environment factors.

Grid Australia (2013, pp.24–5) identified a relatively long list of potential operating environment factors as follows:

- 'location(s) and type(s) of generation on each network
- variability of generation dispatch patterns due to intermittent generation, for example where contributions from hydro or wind generation are material
- location(s) and distribution of loads, whether centralised or distributed among major flow paths, across each network
- length/distance and topology, that is, the degree of meshing or extension of each transmission network, potentially reflected as "network density"
- system operating voltage and power carrying capabilities of lines
- major circuit structures (for example, single circuit or double circuit, which can impact on credible contingencies in the NEM)
- weather, that is, natural performance characteristics of the network related to storms, bushfires and other weather-related events which in turn can depend on factors such as altitude, wind and the propensity for natural phenomena such as cyclones
- terrain
- peak demand
- different jurisdictional standards such as planning standards
- age and rating of existing network assets
- the timing of a TNSP in its investment cycle, given the lumpy nature of investments
- extent of implications of NER "technical envelope" requirements, such as those in the schedules in Chapter 5 (e.g. voltage stability, transient stability, voltage unbalance, fault levels, etc), and
- variations in cost drivers between jurisdictions.'

Economic Insights agrees that, in an ideal world, it would be desirable to adjust for many of the factors identified by Grid Australia while noting that there is overlap between some of the factors listed and items identified in section 2 as outputs. However, given degrees of freedom and multicollinearity constraints, it will only be possible to adjust for the most important operating environment factors initially. Consequently, we propose a revised initial operating environment factor short list as set out in table 2 below.

Table 2: **Revised operating environment factor short list**

Variable	Definition	Source
Weather factors		
Extreme heat days	Number of extreme cooling degree–days (above, say, 25° C)	BoM
Extreme cold days	Number of extreme heating degree–days (below, say, 12° C)	BoM
Extreme wind days	Number of days with peak wind gusts over, say, 90 km/hour	BoM
Terrain factors		
Bushfire risk	Number of days over 50 per cent of service area subject to equivalent of NSW severe or higher bushfire danger rating	BoM & FAs
Rural proportion	Percentage of route line length classified as rural	TNSPs
Vegetation encroachment	Percentage of route line length requiring active vegetation management	TNSPs
Network characteristics		
Line length	Route length of lines	IDR
Variability of dispatch	Proportion of energy dispatch from non–thermal generators	TNSPs
Concentrated load distance	Greatest distance from node having at least, say, 30 per cent of generation capacity to node having at least, say, 30 per cent of load	TNSPs

In addition to seeking stakeholder feedback on this revised short list we also seek stakeholder input in developing a measure of the following:

- network density variable to reflect degree of meshing versus extension of network.

Weather

Extremely hot days now place very high loads on TNSP networks due to the high penetration of domestic air conditioners (among other things). Similarly, extremely cold spells can also place high demands on TNSP networks as greater use is then made of space heating. While the fuel source primarily used for space heating will vary from region to region, with gas being the major source in very cold areas, the increasing penetration of domestic air conditioners is likely to see increasing demand for electricity as greater use is made of reverse–cycle air conditioning for heating. Extreme hot and cold days can both be expected to place unusually high demands on energy networks and networks have to be built to handle those extremes. Consequently, when undertaking efficiency comparisons it is desirable to allow for variations in extreme conditions across TNSPs. That is, if we have two otherwise identical TNSPs but one operates in a climate of greater temperature extremes (but the same overall average temperature) then the one operating in the more extreme conditions will require more inputs to handle the higher peak demands it faces. As well as impacts on peak demand, extreme hot and cold conditions will also impact operationally on the TNSP.

A common way of measuring the need for cooling and heating is by calculating the number of ‘degree–days’. A degree day is determined by calculating the mean daily temperature for the day and forming a difference between that daily mean and a base temperature. The mean daily temperature can be calculated by taking the average of the daily maximum and minimum temperatures.

The Australian Energy Market Operator (AEMO 2011, p.1) defines cooling degree days as follows:

> ‘A measurement designed to reflect the amount for energy required to cool a home or a business. The number of degrees that a day’s average temperature is above a base temperature (18.5° C), the temperature above which buildings need to be cooled.’

It similarly defines heating degree days as follows:

> ‘A measurement designed to reflect the amount for energy required to heat a home or a business. The number of degrees that a day's average temperature is below a base temperature (e.g. 18.5° C), the temperature below which buildings need to be heated.’

For the current application instead of using a so–called ‘balance point’ above which cooling is required and below which heating is required in calculating the number of degree–days, we suggest calculating extreme cooling degree days relative to a higher base temperature, say 25° C and extreme heating days relative to a lower base temperature, say 12° C. The precise values of the baselines would need to be determined in consultation with industry and meteorological experts.

The temperature data required to calculate the numbers of extreme degree days are collected by the Bureau of Meteorology. An average result would need to be taken for a representative sample of weather reporting stations spread across each TNSP’s load centre area and route length.

Extreme wind days can also pose problems for TNSPs and make it more likely trees and windborne debris will make contact with lines. High winds are also associated with extreme weather conditions such as cyclones and tornadoes. We propose to measure these effects by the number of days recorded with wind gusts above, say, 90 km/hour. This is the start of the ‘storm’ wind force classification which is above ‘gale’ force but less than ‘hurricane’ force. The wind data required to calculate the numbers of extreme degree days are collected by the Bureau of Meteorology. An average result would need to be taken for a representative sample of weather reporting stations spread along each TNSP’s route length.

Terrain

Economic Insights (2013b) noted that the terrain of a TNSP’s service area can have an important effect on its costs while being clearly beyond the TNSP's control. However, we also noted that there is currently a dearth of terrain summary indicators. Following discussions with stakeholders, we believe a useful start can be made by including three simpler and tractable indicators.

The first relates to the bushfire risk the TNSP faces as a result of its line locations and terrain. TNSPs operating in high bushfire risk areas will need to undertake more stringent vegetation management, inspection and maintenance programs, thus increasing their costs relative to TNSPs operating in more temperate areas. A readily tractable way of measuring the bushfire risk faced by a TNSP is to measure the number of days in a year that over half its line length is subject to a bushfire danger rating of equivalent of NSW 'severe' or higher (ie severe, extreme or catastrophic). The source data are held by state and territory fire authorities and by the Bureau of Meteorology. It is noted that the basis of bushfire danger classifications may vary somewhat across jurisdictions.

The second simple indicator of terrain we believe worthy of inclusion on the short list is the percentage of the TNSP's total line length that is classified as being in a rural area. This provides a ready way of distinguishing the extent to which the TNSP operates in rural areas as opposed to urban areas. Rural areas will often impose higher costs on the TNSP, particularly where lines traverse mountainous and forested areas and where there is a higher bushfire danger risk.

The third simple terrain indicator relates to the degree of vegetation growth and encroachment on TNSP lines. TSNPs traversing forested and other heavily treed areas will typically have to spend more on vegetation management than TNSPs traversing grass land and other non–treed areas. We propose to capture this effect by the percentage of a TNSP's route line length requiring active vegetation management. This information would need to be collected from TNSPs but be subject to external verification and review.

Network characteristics

As noted by Grid Australia, the characteristics of a network will have an impact on TNSP costs and many of these effects are beyond management control.

The distance a transmission line has to cover and the capacity required to service the size of the end load centre will, of course, be important drivers of TNSP costs and may also be important drivers of measured TNSP efficiency. Generators have traditionally been located close to coal fields and the main transmission lines have run from those generators to the major cities. Other transmission lines of possibly longer length and generally lesser capacity service regional load centres. The length and capacity of transmission lines required are largely beyond TNSP control and are primary cost drivers. As with other operating environment factors, a decision on whether to include route length as a proxy for TNSP length and capacity would need to be made in conjunction with the output specification to be used to minimise double counting and multicollinearity problems.

Some TNSPs will have relatively short distances between concentrated generation centres and concentrated large load centres. This will typically place these TNSPs at an advantage compared to TNSPs with more diffuse generation centres and more diffuse and smaller load centres. The greatest distance from a node having at least, say, 30 per cent of generation capacity to a node having at least, say, 30 per cent of load could be a useful indicator of this factor.

Similarly, a TNSP serving a concentrated group of thermal generators will generally have an advantage compared to a TNSP with a similar load but having to serve many diffuse non–thermal generators such as hydro and wind turbines which only generate for part of the day. The proportion of dispatch from non–thermal generators could be a useful indicator of this factor.

Finally, we require an indicator to measure transmission network density to reflect the degree of meshing versus extension of the network. Generally, a more meshed network will be able to provide higher levels of reliability than a more 'stringy', less meshed network. One possible indicator is MVA system capacity per route kilometre of line. We seek stakeholders views on how such an indicator should be formed.

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