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

Briefing Notes prepared for
Australian Energy Regulator

16 April 2013

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CONTENTS

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 fourth workshop which is on measuring outputs and operating environment factors to be used for economic benchmarking of electricity distribution network service providers (DNSPs).

Outputs – issues for discussion

Data requirements

The DNSP 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 DNSP Regulatory Information Notices (RINs). 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 DNSPs?*

Network capacity or peak demand?

Many analysts have likened a DNSP'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 a DNSP 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 with adjustment for customer density differences as an operating environment factor should be investigated.

Given that system capacity and peak demand both have some limitations as outputs, an alternative could be to include customer numbers disaggregated by customer class and reliability as outputs. Together these variables could measure the DNSP's success in providing adequate capacity to meet customer needs.

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 using disaggregated customer numbers and reliability an alternative to using system capacity or peak demand?*

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 DNSPs 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 DNSPs. 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 DNSPs 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

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 customer–minutes lost or total customer interruptions (ie transformed SAIDI or SAIFI, respectively) 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 customer 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 DNSP'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 DNSP's costs of improving reliability. We recommend adopting the STPIS valuations of customer outages (known as the value of customer reliability) to ensure consistency between incentive schemes and economic benchmarking. 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 DNSP 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 DNSP outputs in economic benchmarking studies:

- customer numbers (total or by broad class or by location)
- smoothed non–coincident peak demand
- system capacity (taking account of both transformer and line/cable capacity)
- reliability (total customer minutes off–supply and/or total customer interruptions), and
- throughput (total or by broad customer class or by location).

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

Scope of Services

In addition to providing the core 'poles and wires' component of distribution networks, DNSPs also provide a range of supplementary services. These include customer funded connections, disconnections, emergency recoverable works, various metering services, inspection services, public lighting, energising/de–energising networks and other customer–specific services. The regulatory treatment of these 'non–core' activities has varied widely across the state and territories and legacy arrangements continue to impact current regulatory determinations.

For economic benchmarking purposes we ideally need a common coverage of activities and, importantly, costs across all DNSPs. Given the current wide range of regulatory treatments of non–core activities, common coverage could be achieved by going with either a wide definition of included activities for economic benchmarking purposes or a narrow definition.

The most practical way forward is to adopt a narrow definition which includes only the network services group. This has the advantages of covering the core 'poles and wires' activity and only requiring data from the DNSP itself on standard control services. However, it will require DNSPs which have other items classed as standard control services to exclude those activities. That is, connection services and metering, in particular, will need to be excluded from reported data using the relevant ring fencing arrangements.

10) *Do you foresee any problems with adopting the narrow network services group coverage of DNSP activities?*

Operating environment factors – issues for discussion

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

- density
  - customer density (customer/kilometre of line)
  - energy density (MWh/customer)
  - demand density (kVA non–coincident peak demand/customer)
- 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 service area subject to severe or higher bushfire danger rating)
  - rural proportion (percentage of line length classified as short rural or long rural)
  - vegetation encroachment (percentage of route line length requiring active vegetation management)
- service area
  - route length of lines.

The decision on which operating environment factors to include will need to be made in conjunction with the output specification used to minimise double counting and possible multicollinearity problems.

11) *Have we included the main operating environment factors?*

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 first workshop of the second phase (and the fourth overall) on measuring outputs and operating environment factors to be used for economic benchmarking of electricity DNSPs.

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 DNSPs and presents some preliminary output variable definitions. The fourth section discusses issues associated with the scope of services to be covered by economic benchmarking. Finally, the fifth section discusses a number of operating environment factor considerations and presents a revised short list of key indicators.

2 DNSP OUTPUT QUANTITY AND PRICE ISSUES

The primary issue for discussion at the fourth workshop is whether the DNSP 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 DNSP RINs. 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 DNSPs.

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

2.1 Network capacity or peak demand?

There was some discussion at the first workshop as to whether it was more appropriate to include system capacity or peak demand as the primary functional output DNSPs supply. Economic Insights (2013a) noted that DNSP representatives had previously likened a DNSP'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 DNSP'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 any particular time.

Other analysts, such as Turvey (2006), have made a similar point:

> 'what the enterprise provides is not gas, electricity, water or messages; it is the capacity to convey them. It follows that, to compare efficiencies, it is necessary to compare differences in capacities with different costs.'

A criticism, however, of including system capacity as a functional output is that it does not distinguish between those DNSPs who have provided just enough system capacity to meet peak demands 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. A number of workshop participants advocated the use of peak demand as a better measure of the load a DNSP has to be able to accommodate and as a more appropriate proxy for required system capacity. Economic Insights (2013a, p.11) noted that system peak demand tends to be quite 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 DNSP representatives at the workshop suggested that the forecast peak demand series that the

DNSP's previous price determination had been based on was a more appropriate peak demand series than actual peak demand.

Another DNSP representative suggested that, while the road network analogy was useful, a more relevant analogy might be to consider the case of a customer who has a requirement for electricity but there is no distribution network. The customer needs a way of getting the energy he requires from the transmission terminal station to his premises. The energy will be acquired from the NEM by the customer's retailer and is available at the terminal station at the relevant voltage.

In the absence of a distribution network the customer must construct its own poles and wires and transformers from the terminal station to its premises. Those facilities must have the capacity to meet the customer's demand, whatever it is, with the required reliability. The optimal size, and hence cost, of those facilities will be determined by the customer's:

- forecast maximum peak demand at some time in the future where the optimum capacity is a trade–off between building less capacity now in the knowledge that expansion will be required at some later time, and building more capacity now at higher cost but deferring the need for expansion. Once capacity is installed it cannot be readily removed or down–sized.
- reliability requirements which will determine, among other things, the level of redundant/standby capacity required. Once again that would be an optimisation and could involve standby transformers and circuits or even a second line of poles and wires from a different terminal station or back-up generation onsite.

The capacity which will be provided is not determined by:

- energy throughput/load factor, although load factor may determine whether the customer builds 'distribution' assets at all. For example, if a customer has a very low load factor and/or is a long way from the terminal station, it may determine that it can meet its total energy, capacity and reliability requirements more economically by generating onsite.
- actual peak demand as it is from time to time.

This example implies that the principal output of the facilities that the customer installs, which are in fact distribution assets, is the capacity to carry energy when and as required from the terminal station to the customer's premises. There is also a correlation between installed capacity and reliability – all else equal, a system that has greater capacity/redundancy can be expected to meet demand, whatever it is from time to time, more reliably than one with less capacity/redundancy. Furthermore, capacity cannot track short term variations in actual peak demand, so there is invariably be some level of spare capacity in the system.

Once distribution is expanded to form a network then connections also become an output. And a network, as an aggregator, can take advantage of diversity so that total network capacity is only some fraction of the sum of individual customers' capacity requirements. A network also offers the benefits of economies of scale.

In its submission on the AER (2012a) Issues Paper, Jemena (2013, p.8) summarised the situation as follows:

> ‘an NSP’s principal functions are to provide connections and ensure that there is sufficient capacity to meet network users’ peak requirements, whatever they are and whenever they occur, in all but extreme “1 in N” circumstances.
>
> ‘We note that benchmarking studies often use observed peak demand as a proxy for capacity. We see this as problematic in that it implies that an efficient business is one that has just enough capacity to meet actual peak demand. That may have superficial attraction but it is not achievable in practice and is not dynamically efficient—capacity can only be increased in finite increments and, when additional capacity is required, it is more efficient to install “excess” capacity to meet forecast demand growth for a period than to expand in frequent small increments. It follows that there will always be spare capacity in a network. At the same time, there will be local bottlenecks as local peak demand increases to the limit of capacity installed at some earlier date to serve that locality. For an established NSP, total installed capacity changes only incrementally from year to year in response to the forecast trend in maximum peak demand and as local bottlenecks are addressed. It certainly does not change in response to short term variations in actual peak demand due to weather variations between years.
>
> ‘Actual throughput and actual peak demand are not significant cost drivers in the short term: the provision of capacity to accommodate forecast maximum peak demand is a much more significant driver of input requirements and costs. The distributor is (and must be) compensated for the incurred cost of providing prudently installed capacity notwithstanding the fact that actual peak demand will vary and may reach the limit of capacity only rarely.’

SP AusNet (2013, p.22) noted in its submission:

> ‘forecast peak demand, as approved in regulatory determinations, is what businesses are required to provide sufficient capacity for. As such, it drives investment planning and decision–making, and forms a basis for regulated revenues. In contrast, actual peak demand is not relevant as this is outside the control of the business and is not a driver of revenues.’

And SA Power Networks (2013, p.2) noted:

> ‘Network capacity should be considered with regard to peak demand forecasts. Networks seek to ensure supply during periods of extreme peak demand at an efficient level of costs.
>
> ‘Measures of spatial peak demand should be used rather than the system demand.’

Economic Insights agrees that actual peak demand is a poor indicator of the load capacity a DNSP 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 DNSP 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, DNSPs 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 DNSPs to over–inflate forecasts in future reviews.

Maximum demands will provide an indication of the transformer capacity required by the DNSP, all else equal. They do not distinguish between the amount of lines required by two DNSPs who may have similar maximum demands but one of which is rural and the other of which is urban. One would expect the rural DNSP, having a lower customer density, to require a higher length of line to deliver the same forecast maximum demand. This will require the rural DNSP 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, customer density 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. 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 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 supplied rather than a forecast capacity requirement that may or may not be met. And it does not have the volatility beyond the DNSP’s control which is a problem with the actual peak demand measure.

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 with adjustment for customer density differences as an operating environment factor should be investigated.

Given that system capacity and peak demand both have some limitations as outputs, an alternative could be to include customer numbers disaggregated by customer type (eg residential, commercial, small industrial, large industrial and other) and reliability as outputs. Together these variables could measure the DNSP’s success in providing adequate capacity to meet customer needs. Such a specification also warrants further investigation and analysis.

2.2 Calculating output weights

There was general agreement at the first 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 DNSP pricing structures have often evolved on the basis of convenience rather than on any strong relationship to underlying relative costs. 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.

In its submission on AER (2012a), United Energy noted:

> 'UE agrees … that the absence of prices that reflect costs necessitates a move away from simple revenue shares as the basis for weighting the outputs. In no way [are revenue shares] likely to be a true representation of either the value to the end customer of a particular output, or the cost to the business of providing that output.'

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

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:

$$\ln C_{OM} = b_0 + b_D \ln D + b_C \ln C + \ln W_{OM} + 0.5 b_{DD} \ln D \ln D + 0.5 b_{CC} \ln C \ln C + b_K \ln K + b_t t \tag{5}$$

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 DNSPs.

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.

Obtaining relative cost estimates directly from DNSPs

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 DNSPs 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 DNSP 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 DNSP'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 DNSP to demonstrate that it is meeting the specified requirements.

This means that a DNSP 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 DNSP 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 need to consult with DNSPs in advance of collecting these costs estimates to develop consistent, robust definitions of costs and to ensure as consistent a treatment as possible across DNSPs.

2.3 Reliability

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

In its submission on the AER (2012a) Issues Paper, SP AusNet (2013, p.22) noted:

> 'Reliability is an important output variable, as it is something which customers value which is reflected in the NER capex and opex objectives. While there are practical challenges in expressing reliability as outputs in benchmarking functions, it is worthwhile trying to overcome these challenges given the importance of reliability as an output.'

Similarly, the Major Energy Users Group (2013, p.31) observed:

> 'Ultimately consumers measure the value of the network in terms of amount of energy used and the reliability of supply as measured by SAIDI, SAIFI and other similar measures. Less investment is needed if these measures are low and more is needed when they are high. So using these measures provides a good indication of what investment is needed and where.'

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

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

- is there a lag between expenditure changes and changes in reliability?
- how can reliability indexes be included as output quantities? and
- what weight should reliability outputs get?

Possible lags between expenditure and reliability changes

Several DNSP representatives at the first workshop suggested there was likely to be a lag between changes in expenditure and observed changes in reliability. However, no explanations were given as to why this might be the case. There will be some timing issues between years when expenditure is incurred and when a change in reliability might be observed. For example, expenditure at the end of one regulatory year may only lead to improved measured reliability in the next regulatory year. However, we would expect expenditure on improving reliability to be spread over the year which would considerably lessen this impact.

Lags could also be observed if there is a program of expenditure required to upgrade troublesome feeders which takes some time to implement. For instance, only obvious weak points may be easily identified and remedied initially. However, this may then lead to other weak points on the feeder becoming more obvious which then require further expenditure and so on over a number of years.

Some DNSPs in remote parts of Australia have previously observed that it normally takes around three years for capital expenditure aimed at improving the performance of worst feeders to have a significant effect. This is because it takes time to complete interrelated projects aimed at strengthening the system overall. This would point to a relationship between input use now and reliability performance in two to three years' time. Others have observed that the lag may go in the opposite direction as it takes time for DNSPs to recognise problem areas, get approval for expenditure and then to implement the work program. This would point to a relationship between input use now and reliability performance two years ago.

The reverse is also likely the case. That is, if a DNSP stops spending on maintaining and improving its network then it may take a number of years for the network to 'run down' and the DNSP's reliability performance to drop off noticeably.

Reliability variables have been included in very few economic benchmarking studies to date (see ACCC/AER 2012, AER 2012a). Those that have included reliability measures (eg Coelli et al 2008, 2010 and Lawrence 2000) have typically not lagged them.

While there may be some grounds for expecting there to be a small lag between expenditure on reliability improvement initiatives and observed changes in reliability, we are of the view that initial economic benchmarking studies should include current year reliability. Once a longer time series of data becomes available there will be an opportunity to undertake more formal testing of whether any lag is in fact present and which direction it goes in and to undertake sensitivity analysis of economic benchmarking results to including a lag on reliability variables. It would also be useful to examine the effects of including a rolling average reliability measure rather than a single year reliability measure. We expect the majority of the relationship to be captured in the current year.

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 interruptions 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 which is what SAIDI measures. 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. 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. We believe this representation is more consistent with the framework of economic benchmarking where we are looking at total outputs rather than outputs per customer. SAIDI and SAIFI are useful for communication purposes in that an individual customer can more readily understand what they mean but the overall total numbers of customer–minutes lost and customer interruptions are more appropriate for economic benchmarking studies.

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). Regulators in Finland and Norway have also used economic benchmarking models which included customer–minutes lost as an input whose cost is added to the DNSP's operating and capital costs, in recognition of the costs interruptions impose on customers (WIK–Consult 2011). This approach also warrants consideration.

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 customer–minutes lost or total customer interruptions (ie transformed SAIDI or SAIFI, respectively) 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 customer 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 SAIDI representing higher reliability when subtracted from the benchmark level would produce a higher output quantity than would a high value of SAIDI 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 DNSPs (eg grouped by CBD, urban, short rural and long rural) 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. The weighting method used would need to recognise diminishing customer valuations of improved reliability versus increasing DNSP marginal costs of providing further improvements.

A decision has to be made on whether priority should be given to including outage duration or number of outages performance in initial economic benchmarking studies. Most economic benchmarking studies to date have included duration of interruptions or minutes off–supply as the measure of reliability performance. We recommend that priority be given to including outage duration in the initial round of economic benchmarking studies in line with previous practice. However, we note that a case can be made that the number of customer interruptions is of most concern to customers in systems with high levels of reliability. That is, four separate interruptions of 15 minutes duration each on separate days may cause a customer more inconvenience than one interruption of 60 minutes duration at a similar time of the day.

While the number and length of interruptions are likely to be of most concern to customers and, hence, should receive highest priority for inclusion as outputs in economic benchmarking, other aspects of overall service quality such as momentary interruptions, customer service, quality of supply, etc are candidates for future inclusion.

What weight should reliability outputs get?

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. Consumers typically exhibit reduced marginal willingness to pay as the amount of quality increases. That is, as they attain higher quality levels, 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.

DNSPs, 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 consumer’s marginal willingness to pay is equal to the DNSP’s marginal cost to improve service quality. For service quality levels below the optimum, consumers value a small increase in service quality by more than it costs the DNSP to produce it while for service quality levels higher than the optimum level, it costs the DNSP more to produce a small increase in quality than consumers value it.

For economic benchmarking purposes we need to decide whether reliability outputs should be valued according to the cost to the DNSP of improving reliability or according to the value placed on reliability by the consumer. The methods outlined in the previous section can be used to obtain estimates of the costs to the DNSP of reliability outputs. There are also a range of estimates of the value 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 consumers' valuation of reliability performance (AER 2008b) and, for consistency, is likely to be the best source of estimates of customer valuation of reliability for economic benchmarking purposes.

If the STPIS is working as intended, we would expect customer valuations of reliability to be approximately equal to DNSP marginal costs of further improving reliability. However, we believe a good case can be made that reliability outputs should be valued according to the customer's valuation rather than the DNSP's costs of improving reliability. Given that customers will value successive improvements in reliability successively less highly whereas they will cost DNSPs increasingly more to supply, it is important that DNSPs not be given an incentive to keep increasing reliability beyond the point where their marginal costs exceed customers' marginal valuations of additional reliability.

Some European regulators have adopted a broadly similar approach although, as noted above, 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).

Lawrence (2000) also valued the (undesirable) reliability output using an estimate of customer inconvenience from outages. Lawrence (2000) allocated a directly calculated value to the reliability variable based on 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 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 consumer valuation of reliability in Australia. If this process were to be adopted now, the customer valuations of reliability included in the STPIS 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 we recommend adopting the STPIS valuations of customer outages. 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 interruptions. This method is easy to implement and produces relatively robust results.

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. This would lead to a DNSP with good reliability performance receiving a higher weight for that good performance than a DNSP with bad performance would receive for its performance. That is, the DNSP 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.

2.4 Throughput and other issues

Most workshop participants noted that although DNSPs generally derive the bulk of their charges from energy throughput, changes in throughput are not a significant cost driver and, hence, throughput should not be considered a significant output. For example, United Energy and Multinet (2013, p.10) noted:

> 'UE particularly agrees with the concerns expressed by the AER over the use of energy (throughput) as an output, given that this is not a material cost driver, and given that recent empirical evidence illustrates the risk of declining (or at least plateauing) energy consumption in combination with increasing demand and therefore augmentation related capital expenditure.'

Similarly, the MEU (2013, p.31) noted:

> 'Whilst energy used (because it is easily measured) is the measure that consumers assess their costs by, it is not the main driver of investment needed in a network.'

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. Disaggregation by type of customer and broad time of use (ie peak, off–peak, etc) should also be considered and the relevant data collected.

United Energy and Multinet (2013, pp.10–12) argued that ideally the probabilistic nature of energy supply should be taken into account in specifying outputs. It argued that 'value of energy at risk' could conceptually be considered a key output of DNSPs. This would align with the methodology some DNSPs use to derive their capital augmentation programs, allow greater granularity by allowing different users to be accorded different values and be more consistent with a cost/benefit framework whereby inputs would only be added if their cost was less than expected revenue from additional output.

Economic Insights has sympathy with moves to include more allowance for the probabilistic nature of the environment DNSPs operate in. However, we believe this is in the category of future refinement and the priority is to first fully develop a simple deterministic framework. United Energy and Multinet (2013, p.11) noted:

> ‘That said, UE notes that engineering calculations of the value of energy at risk are complicated by the many combinations and permutations of energy flows across different segments of the network, and multiple scenarios of potential asset failures, with the result therefore being that significant further work would need to be done before confirming whether such an approach (even a scaled back version of existing approaches) could, in practice, be used to calculate a business wide energy at risk amount (noting that UE is unable to undertake a whole of network calculation of the value of energy at risk at present). Furthermore, even if it could be undertaken in practice, consideration would need to be given to those parts of the distribution network whose augmentation is not underpinned by energy at risk calculations, and also, those networks where deterministic standards are in place.’

It was also noted that the probabilistic nature of the risk of asset failure should also ideally be taken into account. Just as asset failure will likely impact on reliability, it will also have other potential impacts such as bushfire ignition. If the DNSP’s input decisions reduce the risk of starting a bushfire, United Energy and Multinet argued this reduced risk should ideally be recognised as an output. Again, while we are sympathetic with the principle being advanced, we believe this an area for future refinement once a more basic framework is operational.

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 DNSP outputs in economic benchmarking studies:

- customer numbers (total or by broad class or by location)
- non–coincident peak demand
- system capacity (taking account of both transformer and line/cable capacity)
- reliability (total customer minutes off–supply and/or total customer interruptions), and
- throughput (total or by broad customer class or by location).

More specific definitions of the short listed outputs are provided in appendix A.

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 peak demand would generally be used as an alternatives rather than both being included as outputs.

3.2 Data requirements

The DNSP 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 DNSP Regulatory Information Notices (RINs). 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 DNSPs.

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

Variable	Unit	Definition of variable	Data in RINs?
DUOS REVENUE for regulated business activities		Annual Revenue earned from the provision of Standard Control Services only. Annual Revenue for the relevant year – in $ of the year. Use actual billing period data – ie without correction for "change in unread consumption" of metered customers in adjacent reading billing periods	Yes, no segregation by classes, chargeable quantity, etc. Given in $'000 nominal.
Revenue Grouping by chargeable quantity			
Revenue from Fixed Customer Charges	$m	Supply availability charges independent of usage	
Revenue from Energy Delivery charges where time of use is not a determinant	$m	Revenue from metered supplies without time of use metering	
Revenue from On–Peak Energy Delivery charges	$m		
Revenue from Shoulder period Energy Delivery Charges	$m	Revenue from metered supplies with time of use metering. Include regularly controlled load in Off-peak.	
Revenue from Off–Peak Energy Delivery charges	$m		
Revenue from energy delivered for uses which are "calculated" rather than "metered"	$m	Revenue from delivery of annual energy for traffic controls, phone or transport cubicles etc	
Revenue from Contracted Maximum Demand charges	$m	Annual Revenue from charges related to a "contracted" maximum demand, charged whether the demand is actually reached.	
Revenue from Measured Maximum Demand charges	$m	Annual revenue from charges related to measured maximum demands, whether "monthly reset" or "ratcheted"	
Revenue from other Sources	$m		
Total Revenue of the above	$m		
Revenue Grouping by Customer type or class			No segregation
Revenue from Domestic Customers	$m	Revenue generally from those with personal residential use	
Revenue from Commercial Customers	$m	Revenue generally from those not on demand tariffs	
Revenue from Small Industrial Customers	$m	Revenue generally from those on LV demand tariffs	
Revenue from Large Industrial Customers	$m	Revenue generally from those on HV demand tariffs	
Revenue from non-metered supplies	$m	Revenue from delivery of annual energy for traffic controls, phone or transport cubicles etc	

Variable	Unit	Definition of variable	Data in RINs?
Revenue from Other Customers	$m	Including eg agricultural, irrigation, etc	
Total Revenue of the above	$m		
Revenue (penalties) allowed (deducted) through incentive schemes (eg S factor) – $m	$m		
ENERGY DELIVERY			
Total Energy delivered	GWh	The amount of electricity transported out of the DNSP's network in the relevant regulatory year (measured in GWh). Metered or estimated at the customer charging location rather than the import location from the TNSP	
Energy Grouping - Delivery by chargeable quantity		Quantities relating to the chargeable revenue items listed above	Yes. Segregation sought is by customer type (domestic or non-domestic) and by supply voltage (S/T, HV or LV)
Energy Delivery where time of use is not a determinant	GWh	Energy to metered supplies without time of use metering or where time of use charging is not applied	Segregation by time of use not sought. “Controlled load” sought.
Energy Delivery at On-peak times	GWh	Energy to metered supplies with time of use metering used for time of use charging. Include regularly controlled load in Off-peak.	
Energy Delivery at Shoulder times	GWh		
Energy Delivery at Off-peak times	GWh		
Energy delivered for uses which are “calculated” rather than “metered”	GWh	Energy calculated as supplied for eg street lighting, traffic controls, phone or transport cubicles etc	Not sought
Energy - Received from TNSP by time of receipt			
Energy into DNSP network at On-peak times	GWh	Energy received into the DNSP network as measured at supply points from the TNSP.	
Energy into DNSP network at Shoulder times	GWh		

Variable	Unit	Definition of variable	Data in RINs?
Energy into DNSP network at Off-peak times	GWh		
Energy Grouping - Customer type or class		Energy relating to the Customer Classes above	Yes.
Domestic Customer Energy Deliveries	GWh	Generally those with personal residential use	Segregation by customer type (domestic or non-domestic) and by supply voltage (S/T, HV or LV)
Commercial Customer Energy Deliveries	GWh	Generally those not on demand tariffs	
Small Industrial Customer Energy Deliveries	GWh	Generally those on LV demand tariffs	
Large Industrial Customer Energy Deliveries	GWh	Generally those on HV demand tariffs	
Other Customer Energy Deliveries	GWh	Including eg agricultural, irrigation, etc	
Delivery time period definitions			Not sought
On-peak changing periods	Days & hours	Days and hours when charges are at On-Peak time rates	
Shoulder charging periods	Days & hours	Days and hours when charges are at Shoulder time rates	
Off-peak charging periods	Days & hours	Days and hours when charges are at Off-Peak time rates	
SYSTEM DEMAND			
System Demand characteristics			
Non–coincident Summated Raw System Annual Peak Demand	MW and MVA	Summation of actual raw maximum demands at the TNSP supply locations level independent of when they occur ie no weather normalisation etc	Yes – sought in MW and MVA. Raw and normalised sought. Summer and winter sought. Detail sought by zone substation
Coincident Raw System Annual Peak Demand	MW and MVA	Summation of actual raw demands at the TNSP supply locations at the time when this summation is greatest ie no weather normalisation etc	Yes – sought in MW and MVA. Raw and normalised sought
Demand supplied[1]			

[1] For customers charged on this basis

Variable	Unit	Definition of variable	Data in RINs?
Summated Chargeable Contracted Maximum Demand	MW and MVA	Summation here is of chargeable (monthly) demand bases for an annual charged quantity	
Summated Chargeable Measured Maximum Demand	MW and MVA	Summation here is of chargeable (monthly) demand bases for an annual charged quantity	
CUSTOMER NUMBERS			
Distribution Customer Numbers by Customer type or class		The average of the number of customer connection points measured on the first day of the Relevant Reporting Year and on the last day of Relevant Reporting Year. A metered customer is identified as having a National Metering Identifier. Customer Numbers relating to the Customer Classes above.	No segregation by customer type – see below
Domestic Customer Numbers	number	Generally the number with personal residential use	
Commercial Customer Numbers	number	Generally the number of non-domestic customers not on demand tariffs	
Small Industrial Customer Numbers	number	Generally the number on LV demand tariffs	
Large Industrial Customer Numbers	number	Generally the number on HV demand tariffs	
Unmetered Customer Numbers	number	Customers where calculation is made for delivery of annual energy for eg street lighting, traffic controls, phone or transport cubicles etc	Yes. Segregated by CBD, Urban, Sort Rural, Long Rural
Other Customer Numbers	number	Including eg agricultural, irrigation, etc.	
Distribution Customer Numbers by Location on the network		Network type segregation as defined in STPIS scheme documents for DNSPs.	Yes. Segregated by CBD etc, Domestic / Non-domestic, and by supply voltage ie S/T, HV or LV
Customers on CBD network		Customers of all types and classes in CBD areas.	
Customers on Urban network		Customers of all types and classes in Urban areas.	
Customers on Short rural network		Customers of all types and classes in Short rural areas.	
Customers on Long rural network		Customers of all types and classes in Long rural areas.	

Variable	Unit	Definition of variable	Data in RINs?
Total Customer Number	number		Yes. Start and end of period. Whole network and segregation by CBD, Urban, Rural short, Rural Long. Segregation also by voltage level, S/T, HV, LV Residential, LV non-residential.
SYSTEM CAPACITY			
Distribution System Capacities Variables		Distribution system includes Overhead and Underground lines and cables in service that serve a distribution function, including distribution feeders, and the low voltage distribution system. These lines typically have a voltage of less than 33 kV. Distribution System excludes the final connection from the mains to the customer and also wires or cables for communication, protection or control and for connection to unmetered loads.	Feeder classification - (a) CBD; (b) Urban; (c) Rural Short; (d) Rural Long.

Variable	Unit	Definition of variable	Data in RINs?
O/H network circuit length and typical / averaged MVA capacity of circuit at each voltage		Calculated as circuit length from the Route length (measured in kilometres) of lines in service (the total length of feeders including all spurs), where each SWER line, single-phase line, and three-phase line counts as one line. A double circuit line counts as two lines. Indicate estimated typical or weighted average capacity for the overall voltage class under normal circumstances to be used for MVA x km capability product – limit may be thermal or by voltage drop etc as relevant	Length sought, but segregation is by function (S/T, HV and LV). Capacity not sought. Demand sought.
O/H Low voltage distribution	km & MVA	0.4 MVA used in previous analysis[a]	
O/H HV 11 kV	km & MVA	4 MVA used in previous analysis[a]	
O/H HV 22 kV	km & MVA	8 MVA used in previous analysis[a]	
O/H HV 33 kV (if used as distribution voltage)	km & MVA	15 MVA used in previous analysis[a]	
O/H SWER	km & MVA		
(Other distribution voltages)	km & MVA	Alternatively, "legacy voltages" eg 6.6 kV may be captured into the nearest relevant voltage currently in use.	

Variable	Unit	Definition of variable	Data in RINs?
Sub-transmission capacity variables		Sub-transmission system includes those parts of the distribution system (including power lines and towers, cables, pilot cables and substations as the case may be) that transfer electricity from the regional bulk supply points supplying areas of consumption to individual zone substations, Includes overhead or underground lines and cables that serve a sub-transmission function in a Central Business District (CBD) or Urban area. Included in this category are sub-transmission lines that serve small groups of customers. These lines typically have a voltage of 33 kilovolts (KV) or more.	
O/H S/T 44/33 kV (if used as subtransmission)	km & MVA		
O/H S/T 66 kV	km & MVA		
O/H S/T 132 kV	km & MVA	80 MVA used in previous analysis[a]	
(Other S/T voltages)	km & MVA	Alternatively, “legacy voltages” eg 110 kV may be captured into the nearest relevant voltage currently in use.	
Total overhead circuit km	km		
U/G network circuit length and typical / averaged MVA capacity of circuit at each voltage		Similarly to OH	Length sought, but segregation is by function (S/T, HV and LV). Capacity not sought. Demand sought
U/G Low voltage distribution	km & MVA	0.4 MVA used in previous analysis[a]	
U/G HV 11 kV	km & MVA	4 MVA used in previous analysis[a]	

Variable	Unit	Definition of variable	Data in RINs?
U/G HV 22 kV	km & MVA	8 MVA used in previous analysis[a]	
U/G HV 33 kV (if used as distribution voltage)	km & MVA	15 MVA used in previous analysis[a]	
(Other distribution voltages)	km & MVA	Alternatively, "legacy voltages" eg 6.6 kV may be captured into the nearest relevant voltage currently in use.	
U/G S/T 44/33 kV (if used as subtransmission)	km & MVA		
U/G S/T 66 kV	km & MVA		
U/G S/T 132 kV	km & MVA	80 MVA used in previous analysis[a]	
U/G (Other S/T voltages)	km & MVA	Alternatively, "legacy voltages" eg 110 kV may be captured into the nearest relevant voltage currently in use.	
Total underground circuit km	km		
Distribution power transformer total installed capacity	MVA	Transformer capacity involved in lowest level transformation to the utilisation voltage of the customer. Do not include intermediate transformation capacity here (eg 132 kV or 66 kV subtransmission to 22 kV or 11 kV distribution level). Give summation of normal nameplate continuous capacity / rating (with forced cooling etc if relevant). Include only energised transformers, not cold spare capacity.	Transformer number and MVA capacity sought. Segregation by function (Distribution or Zone Substation)
Distribution power transformer capacity owned by utility	MVA	Transformation capacity owned by the respondent Give nameplate continuous rating including forced cooling if relevant	Not separated

Variable	Unit	Definition of variable	Data in RINs?
Distribution power transformer capacity owned by HVCs	MVA	Transformation capacity from HV to customer utilisation voltage owned by customers connected at HV. This might include eg 11 kV or 22 kV to eg 3.3 kV as well as to LV Alternatively give summation of individual maximum demands of HVCs whenever they occur (ie the summation of single annual MD for each customer) as a proxy for capacity within the HVC.	Not separated
Subtransmission power transformer capacity	MVA	Transformer capacity involved in intermediate level transformation capacity (ie subtransmission voltage eg 132 kV or 66 kV etc subtransmission to distribution level eg 22 kV or 11 kV) Give summation of normal assigned continuous capacity / rating (with forced cooling etc if relevant). Include only energised transformers, not cold spare capacity Assigned rating may be nameplate rating, or rating determined from results of temperature rise calculations from testing.	Transformer number and MVA capacity sought. Segregation by function (Distribution or Zone Substation)
RELIABILITY			
SAIDI (System Average Interruption Duration Index)		The sum of the duration of each unplanned sustained Customer interruption (in minutes) (without any removal of excluded events and MEDs) divided by the total number of Distribution Customers. Unplanned SAIDI excludes momentary interruptions (one minute or less).	
Distribution–related unplanned SAIDI (whole of network)	System minutes	The number of Distribution Customers used to derive SAIDI should reflect the relevant network type: Whole network – total Distribution Customers, etc	Yes. Whole network and segregation by CBD, Urban, Rural short, Rural long

Variable	Unit	Definition of variable	Data in RINs?
SAIFI (System Average Interruption Frequency Index)		Unplanned Interruptions (SAIFI) (without any removal of excluded events and MEDs) - The total number of unplanned sustained Customer interruptions divided by the total number of Distribution Customers. Unplanned SAIFI excludes momentary interruptions (one minute or less). SAIFI is expressed per 0.01 interruptions.	
Distribution–related unplanned SAIFI (whole of network)		The number of distribution customers used to derive SAIFI should reflect the relevant network type: Whole network – total Distribution Customers, etc	Yes. Whole network and segregation by CBD, Urban, Rural short, Rural long. Sought also at feeder level.
ENERGY NOT SUPPLIED			
Energy Not Supplied - Total	GWh	The estimate of energy not supplied to be based on average customer demand (multiplied by number of customers interrupted and the duration of the interruption). Average customer demand to be determined from (in order of preference): (a) average consumption of the customers interrupted based on their billing history (b) feeder demand at the time of the interruption divided by the number of customers on the feeder (c) average consumption of customers on the feeder based on their billing history (d) average feeder demand derived from feeder maximum demand and estimated load factor, divided by the number of customers on the feeder.	
Energy Not Supplied (planned)	GWh	Total energy not supplied minus Energy Not supplied – Unplanned	Sought at feeder level
Energy Not Supplied (unplanned)	GWh	The estimate of energy not supplied (due to unplanned outages) based as above	Sought at feeder level

Variable	Unit	Definition of variable	Data in RINs?
SYSTEM LOSSES			
Line losses – %	percent	Distribution Losses - Calculated as (electricity imported minus electricity delivered) x 100 / (electricity imported) where electricity imported = (total electricity inflow into DNSP's distribution network including from embedded generation) minus (the total electricity outflow into the networks of the adjacent [connected] distribution network service providers or the transmission network(s)).	Yes – as percent of purchases

[a] Used in Lawrence (2003, 2005) based on Parsons Brinckerhoff (2003)

4 SCOPE OF SERVICES

In addition to providing the core ‘poles and wires’ component of distribution networks, DNSPs also provide a range of supplementary services. These include customer funded connections, disconnections, emergency recoverable works, various metering services, inspection services, public lighting, energising/de–energising networks and other customer–specific services. Some DNSPs have also previously set up related businesses such as the supply of cable data services. The regulatory treatment of these ‘non–core’ activities has varied widely across the state and territories and legacy arrangements continue to impact current regulatory determinations.

In undertaking DSNP determinations, the AER first classifies services according to whether they are distribution services or non–distribution services. Distribution services are then classified according to whether they are direct control services, negotiated services or unclassified services. A negotiating framework is specified for negotiated services which are then subject to a negotiate/arbitrate form of regulation under the distribution determination. Unclassified services are not covered by the distribution determination.

Direct control services are then further split into standard control services and alternative control services. Standard control services are generally subject to price or revenue cap forms of control using a building blocks–based determination. Alternative control services are subject to similar forms of control but the determination need not be building blocks–based.

AER (2011) notes that it has proven useful in recent determinations to group distribution services according to the following seven service groups:

- network services
- connection services
- metering services
- public lighting services
- fee–based services
- quoted services, and
- unregulated services.

While network services or core ‘poles and wires’ activities are classed as standard control services in all states and territories, the diverse treatment of the other six ‘non–core’ activities is illustrated in table 2 where the classification of customer–funded connections and customer–specific services is compared across the six jurisdictions in the NEM. Customer–funded connections range from being standard control services in Victoria and the ACT to being unregulated in NSW while customer–specific services range from being standard control services in the ACT to being unregulated in NSW.

For economic benchmarking purposes we ideally need a common coverage of activities and, importantly, costs across all DNSPs. Given the current wide range of regulatory treatments of non–core activities, common coverage could be achieved by going with either a wide definition of included activities for economic benchmarking purposes or a narrow definition.

Table 2: **Comparison of regulatory classification of customer–funded connections and customer–specific services**

	Customer funded connections		Customer specific services	
	Activity description	**Classification**	**Activity description**	**Classification**
NSW service	Design and construction of new connection assets; design and construction of customer-funded network augmentations	Unregulated	Services requested by the customer which includes: asset relocation works; conversion to aerial bundled cable; temporary, stand-by, reserve or duplicate supplies, other customer-requested services which are non-standard	Unregulated
ACT equivalent service	Customer initiated replacements and relocations.	Standard control	Miscellaneous services	Standard control
QLD equivalent service	Design and construction of large customer connections	Alternative control	Services provided on a quoted service basis	Alternative control services
VIC equivalent service	New connections requiring augmentation works	Standard control	Services provided on a quoted service basis	Alternative control services
SA equivalent service	The provision of connections to the extent that a distribution network user is required to make a financial contribution in accordance with the Electricity Distribution Code.	Negotiated services	Non-standard and customer requested services	Negotiated services
TAS equivalent service	Where capital contributions are made by customers. That is, the customer contributes upfront to the cost of connection services.		Aurora (TAS DNSP) provides a range of non-standard services on a quoted service basis.	Alternative control

Source: AER (2011, p.13)

While going with a wider coverage (eg the first six service groups identified above) may be more consistent with the overall functions a distribution network is expected to perform, it is unlikely to be practical given that it would need to include reporting on activities beyond those currently classified as standard control services, some of which are likely to be supplied by an entity or entities other than the DNSP in some jurisdictions.

The most practical way forward is to adopt a narrow definition which includes only the network services group from the list above. This has the advantages of covering the core 'poles and wires' activity and only requiring data from the DNSP itself on standard control services. However, it will require DNSPs which have parts of the second to fifth service groups listed above classed as standard control services to exclude those activities. That is, connection services, metering and public lighting, in particular, will need to be excluded from reported data using the relevant ring fencing arrangements (see AER 2012b).

It was noted at the first workshop that Victorian DNSPs have to do the planning for transmission connection points whereas this is the responsibility of TNSPs in other states. The materiality of this issue is not clear at this point but it may warrant further consideration.

5 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 DNSPs. Economic Insights (2013a) suggested inclusion of customer density, energy density and climatic effects on the short list of operating environment factors. We have expanded our short list for possible inclusion as set out in table 3 below.

Table 3: **Revised operating environment factor short list**

Variable	Definition	Source
Density factors		
Customer density	Customers/route kilometre of line	RIN
Energy density	MWh/customer	RIN
Demand density	kVA non–coincident peak demand (at zone substation level)/customer	RIN
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 severe or higher bushfire danger rating	BoM & FAs
Rural proportion	Percentage of route line length classified as short rural or long rural	RIN
Vegetation encroachment	Percentage of route line length requiring active vegetation management	DNSPs
Service area factors		
Line length	Route length of lines	RIN

Density

As noted in Economic Insights (2013a), density variables are likely to be the most important operating environment factors affecting efficiency comparisons. A DNSP with lower customer density will generally require more poles and wires to reach its customers than will a DNSP with higher customer density but the same consumption per customer making the lower density DNSP appear generally less efficient unless the differing customer densities are allowed for. And being able to deliver more energy to each customer means that a DNSP will usually require fewer inputs to deliver a given volume of electricity as it will require less poles and wires than a less energy dense DNSP would require to reach more customers to deliver the same total volume. This points to including energy density as an operating environment factor which also takes in more effects than a customer mix variable.

Several DNSPs noted that demand density (kVA non–coincident peak demand/customer) is probably a more important operating environment factor to include than energy density as it is peak demand rather than throughput that determines the amount of infrastructure that has to be installed. We have added demand density to the short list.

All of the data required to include the density operating environment factors are included in the output data requirements listed in table 1 above. The choice of which density variables to include in economic benchmarking applications has to be made in conjunction with which output variables to include to avoid double counting of effects and multicollinearity issues. For instance, if both throughput and customer numbers are included as separate outputs, the need to include energy density as an operating environment factor is greatly reduced.

Weather

Extremely hot days now place very high loads on DNSP networks due to the high penetration of domestic air conditioners (among other things). Similarly, extremely cold spells can also place high demands on DNSP 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 distribution 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 DNSPs. That is, if we have two otherwise identical DNSPs 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.

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 DNSP’s service area.

Extreme wind days can also pose problems for DNSPs 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 across each DNSP’s service area.

Table 4: **Candidates for inclusion in development of ‘climatic difficulty’ index**

Factor	Definition
Maximum temperature	Maximum temperature daily recorded by the Bureau of Meteorology within DNSP's service area.
Minimum temperature	Minimum temperature daily recorded by the Bureau of Meteorology within DNSP's service area.
Peak wind gusts	Daily peak wind gusts recorded by the Bureau of Meteorology within DNSP's service area.
Heatwaves	For the DNSP’s service area: • Number of days with a maximum temperature of, say, 30 degrees or higher • Number of three or more consecutive days with an average temperature above, say, 25 degrees
Dry spells (10, 20, 30 and 40 days)	Number of dry spells (say,10, 20, 30 and 40 days) recorded by the Bureau of Meteorology within DNSP's service area.
Storm Events	Number of storm events as defined and recorded by the Bureau of Meteorology within DNSP's service area.
Lightning strikes	Number of lightning strikes recorded by the Bureau of Meteorology within DNSP's service area.

Over time it may be possible to develop a more sophisticated index of 'climatic difficulty' based on a wider range of factors. Possible candidates for inclusion in the development of such an index are listed in table 4 along with preliminary definitions.

Terrain

Economic Insights (2013a) noted that the terrain of a DNSP's service area can have an important effect on its costs while being clearly beyond the DNSP'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 DNSP faces as a result of its service area location and terrain. DNSPs operating in high bushfire risk areas will need to undertake more stringent vegetation management, inspection and maintenance programs, thus increasing their costs relative to DNSPs operating in more temperate areas. A readily tractable way of measuring the bushfire risk faced by a DNSP is to measure the number of days in a year that over half its service area is subject to a bushfire danger rating of 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 DNSP's total line length that is classified as short rural or long rural. This provides a ready way of distinguishing the extent to which the DNSP operates in rural areas as opposed to urban areas. Line length classified as CDB, urban, short rural and long rural is currently collected as part of DNSP RINs. As noted above, rural areas will generally have lower customer and demand densities than urban areas, thus requiring more poles and wires per customer, all else equal.

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

Service area

In its submission on the briefing notes for the first workshop, SA Power Networks (2013, p.2) noted that:

> 'Line length in kilometres needs to be recognised as an environmental factor, and should be used as the most cost reflective measure of service area.'

We agree that a DNSP's route line length is probably the most effective measure of a DNSP's service area. Economic Insights (2013a) noted the difficulties with trying to use land area measurements of service area, particularly where only small parts of a remote region might actually be serviced by the DNSP. Route length gives a more accurate indication of the spread of the DNSP's network.

DNSP RINs currently appear to concentrate on collecting circuit line length data. This would need to be supplemented by separate reporting of route length.

As with other operating environment factors, a decision on whether to include route length as a proxy for service area would need to be made in conjunction with the output specification to be used to minimise double counting and multicollinearity problems.

APPENDIX A: SHORT LISTED OUTPUTS DEFINITIONS

Table A1: **Short listed outputs and preliminary definitions**

Output	Suggested definition
Customer numbers (total or by broad class or by location)	The average of the number of customers measured on the first day of the Relevant Reporting Year and on the last day of Relevant Reporting Year Including inactive, unmetered, disconnected customers where supply is available from the network Segregation by Customer Class (eg Domestic, commercial, small LV industrial, large HV industrial etc) Segregation by location on the network (eg CBD, Urban, Short rural, Long rural)
Non–coincident peak demand	Summation of actual raw maximum demands (MVA and MW) at the TNSP supply locations (grid exit points) independent of when they occur (i.e. no weather normalisation etc).
System capacity (taking account of both transformer and line/cable capacity)	Assigned ratings (MVA) of all energised zone substation power transformers. Excluding VTs, CTs, station service transformers, non-energised and spare units. Nameplate ratings (MVA) of all energised distribution power transformers. Excluding VTs, CTs, station service transformers, non-energised and spare units Power transformer capacity involved in intermediate level transformation capacity (i.e. subtransmission voltages132kV/ 66kV/33kV) to distribution level (i.e. 22kV/11kV/6.6kV) Assigned and nameplate rating to recognise forced air and/or oil cooling adjustments where appropriate.
Reliability (total customer minutes off–supply and/or total customer interruptions)	SAIDI - The sum of the duration of each unplanned sustained Customer interruption (in minutes) (after removing excluded events and MEDs) divided by the total number of Distribution Customers. Unplanned SAIDI excludes momentary interruptions (one minute or less). SAIFI - Unplanned Interruptions (SAIFI) (after removing excluded events and MEDs) - The total number of unplanned sustained Customer interruptions divided by the total number of Distribution Customers. Unplanned SAIFI excludes momentary interruptions (one minute or less). SAIFI is expressed per 0.01 interruptions.

Output	Suggested definition
Throughput (total or by broad customer class or by location).	Energy delivered to customers, measured at the customers locations. Total annual energy and Segregation by Customer Class (eg Domestic, commercial, small LV industrial, large HV industrial etc) Segregation by location on the network (eg CBD, Urban, Short rural, Long rural)

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