Data Collection for Incentive Regulation – Output and Input Measures

Report prepared for
Australian Competition and Consumer Commission

21 October 2004

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AUSTRALIAN CAPITAL TERRITORY   NEW SOUTH WALES   VICTORIA

CONTENTS

1 INTRODUCTION

Meyrick and Associates' (2003c) report titled *Scoping Study into Data Collection Issues for Incentive Regulation* compiled an overarching list of variables it would be desirable to collect to support possible future applications of incentive regulation to electricity distribution and transmission. This list included around 20 different output variables, 45 different input variables and several operating environment variables. The objective of the study was to investigate the data necessary to keep options open to support a range of output and input specifications and modelling approaches that may be considered in any future implementation of incentive regulation.

This report addresses the next stage of the project which involves culling the overarching list of outputs, inputs and operating environment variables to no more than 10 key output variables, 10 key input variables and a few operating environment variables. These variables focus specifically on those required for total factor productivity (TFP) measurement.

The output measures for both distribution and transmission are listed and defined and a brief rationale given for the inclusion of each variable in the following section of the report. We then list, define and discuss input measures in section 3 before looking at operating environment issues in section 4. Wherever possible we use the regulatory reporting framework developed by the Utility Regulators' Forum (2002) to minimise the data collection burden.

2 OUTPUT MEASURES

2.1 Electricity distribution

The key output measures required for electricity distribution TFP measurement are:

- Throughput by broad customer class
- Customer numbers by broad class
- Line and cable length by voltage level
- Coincident peak demand
- Distribution related system average interruption frequency index (SAIFI)
- Distribution related system average interruption duration index (SAIDI)
- Line losses
- Revenue from distribution service by broad customer class

Definitions of the distribution output measures are presented in table 1 and discussion of the rationale for including each follows.

Table 1: **Distribution Output Measure Definitions**

<table>
<tr><th>Output</th><th>Definition</th></tr>
<tr><td>Throughput by broad customer class</td><td>GWh of energy delivered by the distribution network to the following broad customer classes:
• Domestic (less than 70 MWh annual consumption) including controlled supply to off–peak appliances etc
• Commercial and small industrial (greater than 70 MWh but less than 40 GWh annual consumption)
• Large industrial (greater than 40 GWh annual consumption)
• Other (public lighting, unmetered, etc)
• Total energy delivered</td></tr>
<tr><td>Customer numbers by broad class</td><td>The number of customers (average of beginning and end of period) defined as connection points assigned a unique national metering identifier or agreed points of supply for the following broad classes:
• Domestic (less than 70 MWh annual consumption) noting that controlled supply to a domestic customer assumes also uncontrolled supply, and so is counted only once
• Commercial and small industrial (greater than 70 MWh but less than 40 GWh annual consumption)
• Large industrial (greater than 40 GWh annual consumption)
• Other (public lighting, unmetered, etc)
• Total customer numbers</td></tr>
<tr><td>Line length by voltage level</td><td>Network circuit kilometres (route length multiplied by number of circuits per pole at year end) for the following voltage classes:
• Low voltage distribution
• High voltage distribution:
    o 11 kV
    o 22 kV
    o 33 kV (if used as a distribution voltage)
• Single wire earth return (SWER)
• Sub–transmission:
    o 44/33 kV (if used as a sub–transmission voltage)
    o 66 kV
    o 110 kV
    o 132 kV
• Other voltages (please specify)
• Total circuit kilometres
Data for each voltage is to be given separately for overhead and underground circuits. Dedicated circuits for public lighting supply or control should be excluded.</td></tr>
<tr><td>Coincident peak demand</td><td>Maximum coincident network demand in megawatts</td></tr>
</table>

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Table 1: **Distribution Output Measure Definitions (cont'd)**

Output	*Definition*
Distribution related SAIFI	The total number of sustained customer interruptions attributable solely to distribution (post exclusions) divided by the total number of distribution customers. SAIFI excludes momentary interruptions (one minute or less). Excluded events defined using the Utility Regulators Forum (2002) criterion of the outage being caused by an exceptional natural or third party event having a SAIDI impact of greater than 3 minutes, the impact of which the distributor could not reasonably have been expected to mitigate through prudent asset management.
Distribution related SAIDI	The sum of the duration of each sustained customer interruption (in minutes) attributable solely to distribution (post exclusions) divided by the total number of distribution customers. SAIDI excludes momentary interruptions (one minute or less). Excluded events defined using the URF (2002) criterion of the outage being caused by an exceptional natural or third party event having a SAIDI impact of greater than 3 minutes, the impact of which the distributor could not reasonably have been expected to mitigate through prudent asset management.
Line losses	Energy entering the network from all sources (including transmission, embedded generation and cogeneration) less all energy deliveries (including to metered customers, unmetered customers, public lighting, own use and theft), expressed as a percentage of energy entering the network from all sources.
Revenue by broad customer class	Distribution use of system (DUOS) charges (ie excluding transmission fees) for the following broad customer classes: • Domestic (less than 70 MWh annual consumption) including controlled supply • Commercial and small industrial (greater than 70 MWh but less than 40 GWh annual consumption) • Large industrial (greater than 40 GWh annual consumption) • Other (public lighting, unmetered, etc) • Total

The throughput, customer numbers and line length variables cover the three major distribution output dimensions included in most distribution TFP studies. Many analysts have drawn the analogy between an electricity distribution system and a road network. The distributor has the responsibility of providing the 'road' and keeping it in good condition but it has little, if any, control over the amount of 'traffic' that goes down the road. Consequently, they argue it is inappropriate to measure the output of the distributor solely by a volume of sales or 'traffic' type measure. Rather, the distributor's output should be measured by the availability of the infrastructure it has provided and the condition in which it has maintained it – essentially a supply side measure.

Meyrick and Associates (2003a,b) and Tasman Asia Pacific (2000a,b) formed comprehensive output measures which contained three components – throughput, network line capacity and the number of connections. Throughput effectively measures the amount of 'traffic' on the

network while line capacity measures the broad amount of infrastructure capacity the distributor makes available to potentially carry traffic. The customer or connection component recognises that some distribution outputs are related to the very existence of customers rather than either throughput or system line capacity. This will include customer service functions such as call centres and, more importantly, connection related capacity (eg having more residential customers requires more small transformers and poles). This three output specification has the advantage of incorporating key features of the main density variables (customers per kilometre and sales per customer).

When measuring throughput it is important to recognise that different types of customers have different demand characteristics and different cost drivers. For instance, domestic customers each consume relatively small amounts of electricity and are geographically diffuse compared to concentrations of larger industrial customers. Domestic customers thus require extensive low voltage systems and many small distribution transformers whereas large industrial customers may be connected through short lengths of dedicated high voltage lines and a small number of large transformers. Customers supplied directly at high voltage may also provide their own transformation capacity to their utilisation voltages. Consequently, we need to differentiate between broad customer classes when measuring the throughput, customer numbers and revenue distribution outputs.

With the separation of distribution and retail functions, most distributors now have limited information on the type of customers supplied other than their demand and consumption and are unable to readily distinguish between, say, large commercial and small industrial customers. The dividing lines between domestic and commercial/small industrial and between small and large industrial customers vary between jurisdictions but a reasonable dividing line is 70 MWh annual consumption for the first boundary and 40 GWh for the second. Some studies have used a lower boundary of 10 GWh to define large industrial customers but this has the disadvantage of capturing, say, university campuses which would normally be regarded as more akin to a commercial customer.

Measuring system capacity can be done in several different ways. Early studies tended to simply use line length without distinguishing between voltage levels. However, this treats a kilometre of, say, 66 kV sub–transmission line the same as a kilometre of low voltage single wire earth return (SWER) which is clearly inappropriate as it takes no account of the lines' respective capacities. Multiplying length by voltage capacity would be an alternative but does not recognise the engineering restrictions on line capacity caused by the type of cable used and climatic conditions.

Recent studies have estimated the quantity of the distributor's system capacity using its total megavolt–ampere (MVA) kilometres. MVA kilometre conversion factors can be tailored

specifically to reflect operating conditions and the fact that the effective capacity of an individual line depends not only on the voltage of the line but also on a range of other factors, including the number, material and size of conductors used, the allowable temperature rise as well as limits through stability or voltage drop. For instance, Meyrick and Associates (2003b) used factors derived from an engineering study by Parsons Brinckerhoff Associates (2003).

Rather than ask each distributor to nominate its own conversion factors and, hence, number of MVA kilometres, it would be preferable to collect information on line lengths by voltage capacity. This would allow the application of either agreed distributor–specific factors or a common set of conversion factors across all distributors to derive the final MVA kilometre figures.

In collecting information on line and cable lengths, this can be done using either route kilometres (total distance between adjacent poles or analogous trench length) or circuit kilometres (route length multiplied by number of circuits per pole or length of cable per se). Circuit kilometres will provide a superior measure of the distributor's overall line capacity as it takes accounts of multiple circuits strung between the same set of poles or in the same trench.

Coincident peak demand is an important driver a distributor's costs as it has to provide enough transformer and system capacity to cover the maximum demand occurring at any one point in time. A distributor with a relatively even demand pattern over time will thus have lower costs than a distributor supplying the same annual energy throughput but subject to much larger variations in demand levels over time.

Another important dimension of a distributor's output is the quality of supply which encompasses reliability (the number and duration of interruptions), technical aspects such as voltage dips and surges and customer service (eg the time to answer calls and to connect or reconnect supply). This will be an important cost driver as providing a higher quality service typically requires the use of more inputs. Reliability is likely to be the most important of these service quality attributes and the one for which the most data is available. SAIFI and SAIDI are the standard measures of the number of interruptions and total minutes off supply experienced by the average customer in a year. Interruptions can be caused by upstream factors such as a shortage of generation capacity (load shedding), transmission system failures or by problems within the distributor's system. In measuring the distributor's output it is reasonable to only include those interruptions over which it potentially has control, namely those arising from distribution system problems rather than those arising from either generation or transmission. While some argue that planned or notified outages cause less inconvenience to customers than unplanned outages, there is some debate over whether making this distinction provides an incentive for distributors to increase the number of

notifications of potential outages thus causing more inconvenience to customers. Using the total number of distribution interruptions reduces the scope to introduce distortions.

Another important issue is whether reliability is measured before or after the exclusion of the impact of certain exceptional events. It will not be economic to build the distribution network to withstand the impact of relatively rare natural disaster events. Consequently, to provide the appropriate incentive to distributors, the effects of certain types of events on SAIFI and SAIDI are sometimes excluded. In measuring distributors' output it would, hence, be desirable to use a common set of exclusion criteria. The Utility Regulators' Forum (2002, p.4) recommended the exclusion of outages that exceeded an overall SAIDI impact of 3 minutes, where the outage was caused by 'an exceptional natural or third party event, the impact of which the distributor cannot reasonably be expected to mitigate through prudent asset management'. It would be desirable to collect SAIFI and SAIDI data using such a common definition of exclusions. Unfortunately it is not possible to remove a judgemental element from what events qualify for exclusion and this means there is usually a lag in this data becoming available while regulatory decisions are made on which events qualify for exclusion from reported performance.

Line losses are important to monitor to ensure the system is operating efficiently from an engineering perspective but are not readily classified as either an output or an input. For convenience we include them in our list of outputs although, like the reliability indicators, they are effectively 'negative' outputs where a reduction in the measure represents greater output. In this case, dissipating less energy in its transportation is equivalent to a productivity improvement. In calculating line losses it is important to count all energy entering the network and all energy deliveries. Thus, embedded generation and cogeneration contributions need to be counted as well as transmission deliveries to the distribution network. Similarly, deliveries to all identifiable sources need to be counted including both metered and unmetered customers, public lighting, own use in substations, etc and theft.

Finally, distribution revenue should concentrate on revenue from the delivery of the distribution function in isolation. Thus, distribution use of system (DUOS) charges are relevant. Transmission fees should be excluded, as they are a direct upstream pass–through for the distributor. The disaggregation of revenue should be along the same broad customer classes as the throughput and customer number outputs.

2.2 Electricity transmission

The key output measures required for TFP measurement for a transmission network service provider (TNSP) are:

- Throughput
- Maximum demand
- Line and cable length by voltage level
- Transmission circuit availability
- Number of loss of supply events by time
- Average outage duration
- Line losses
- Revenue

Definitions of the transmission output measures are presented in table 2 and discussion of the rationale for including each follows.

Table 2: **Transmission Output Measure Definitions**

Output	*Definition*
Throughput	GWh of energy delivered by the transmission network to the following categories: • Other connected transmission networks • Distribution networks • Directly connected end–users (please specify voltage) • Total energy delivered
Maximum demand	Maximum transmission network demand in megawatts
Line length by voltage level	Network circuit kilometres (route length multiplied by number of circuits per tower at year end) for the following voltage classes: • 500 kV • 330 kV • 275 kV • 220 kV • 132 kV • Other (please specify) • Total circuit kilometres Data for each voltage is to be given separately for overhead and underground circuits.
Transmission circuit availability	Total number of hours for the following: • Circuit hours actually available • Maximum possible number of circuit hours Force majeure events to be excluded.

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Table 2: **Transmission Output Measure Definitions (cont'd)**

Output	*Definition*
Number of loss of supply events by time	The total and planned numbers of loss of supply events by the following outage lengths: • Less than 0.2 minutes (including momentary unavailability pending a reclosure which is successful) • greater than 0.2 minutes • greater than 1 minute. Excluded events to include circuit interruptions caused by third party systems such as intertrip signals from another party, generator outage or by customer installations, and force majeure events.
Average outage duration	Aggregate minutes of duration of all and planned outages divided by the number of respective outage events. Excluded events to include circuit interruptions caused by third party systems such as intertrip signals from another party, generator outage or by customer installations, and force majeure events.
Line losses	Energy sent into the network by connected generators and other TNSPs less energy delivery from the network to other TNSPs, connected distribution networks and directly connected end–users, expressed as a percentage of energy entering the network
Transmission revenue	Transmission use of system (TUOS) charges for the following categories: • Other connected transmission networks • Distribution networks • Directly connected end–users • Total

The rationale for including the various transmission output measures is broadly similar to the corresponding distribution output measures except that there is not an equivalent customer dimension for TNSPs. The TNSP will typically supply at most a handful of other TNSPs and distributors (who in turn supply many thousands of individual end–users) plus a small number of (usually very large) directly connected end–users.

Again, simply measuring the TNSP's output by their throughput alone would be analogous to measuring only 'traffic' and not infrastructure capacity available. Consequently, we need to include both throughput measures and measures of line and cable capacity. Throughput should be broken down into that supplied to other TNSPs, distribution networks and that supplied to directly connected end–users as the latter are likely to be very large industrial users who have quite different demand characteristics to the average end–user. System delivery capacity should again be measured in MVA kilometres with appropriate conversion factors. For the purposes of data collection, requesting line length by voltage class will support the calculation of a range of subsequent capacity measures.

Maximum demand is also an important cost driver for the transmission system as capacity has to be installed to cover periods of peak delivery requirement, not average demand.

The number of loss of supply events and the average outage duration are the broad transmission level equivalents of the SAIFI and CAIDI reliability measures at the distribution level. These transmission outage measures are cruder than the corresponding distribution measures in recognition of the fact that TNSPs do not have a large number of direct customers themselves. Alternative reliability measures would be the SAIFI and SAIDI attributable solely to transmission outages calculated from the ultimate downstream end–users but these measures become problematic where transmission systems are interconnected and probably add little, if any, additional information for the purposes of productivity measurement. Exclusions from the transmission frequency and average outage duration measures should include upstream causes such as generator–induced load shedding, outages caused by third party systems and force majeure events. This again limits coverage to those events the TNSP has control over and could reasonably be expected to have mitigated.

Another reliability measure included is the overall transmission circuit availability. Collection of data on actual circuit hours of availability and maximum possible available circuit hours will allow measurement of both reliability and the efficiency of maintenance activities.

Transmission line losses are also important to monitor to ensure the system is operating efficiently from an engineering perspective but are again not readily classified as either an output or an input. For convenience we include them in our list of transmission outputs.

Finally, transmission revenue should concentrate on revenue from the delivery of the transmission function in isolation. TUOS charges cover this most closely. It is important to again distinguish between revenue from energy transmitted to other TNSPs, connected distributors and that from directly connected end–users due to the importance and special characteristics of these large industrial users.

3 INPUT MEASURES

Most earlier studies of transmission and distribution productivity have included three broad input categories – labour, materials and services, and capital. Labour quantity was usually measured by the number of full–time equivalent staff while labour cost was measured by wages and salaries plus on–costs. However, increasing but varying use of contracting out has made separate identification of a labour input progressively more difficult and any resulting comparisons of partial labour productivity more and more problematic. Some studies such as Tasman Asia Pacific (2000a,b) have attempted to overcome the impact of differing levels of contracting out by requesting information on the labour content of contracted services.

However, most firms now have difficulty accurately estimating this as they are only interested in the overall cost of the contract. The most recent studies such as Meyrick and Associates (2003a,b) have used two broad inputs – operating and maintenance expenditure (opex) and capital. All labour inputs are included in overall operating and maintenance costs. We follow the same approach here but also suggest collecting information on directly employed labour, the only form of labour input that can be accurately identified.

3.1 Electricity distribution

The key input measures required for electricity distribution TFP measurement are:

- Total operating and maintenance expenditure by category (excluding all capital costs, capital construction costs and transmission fees)
- Number of full–time equivalent employees in operating and maintenance activities (including shared overhead allocation)
- Labour cost (including on–costs) of employees in operating and maintenance activities (including shared overhead allocation)
- Line and cable length by voltage level
- Installed transformer capacity (zone substation level by step and distribution level)
- Optimised replacement cost by nature of asset
- Depreciated optimised replacement cost by nature of asset
- Capital expenditure by nature of asset
- Asset life by nature of asset (overall and residual)

Definitions of the distribution input measures are presented in table 3 and discussion of the rationale for including each follows. We also discuss ways of getting more like–with–like comparisons given differences in distribution coverage between states.

Table 3: **Distribution Input Measure Definitions**

Input	*Definition*

Opex by category	The costs of operating and maintaining the network (excluding all capital costs, capital construction costs and transmission fees) by the following categories:
	• Network operating costs
	• Network maintenance costs:
	    o Inspection
	    o Maintenance & repair
	    o Vegetation management

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Table 3: **Distribution Input Measure Definitions (cont'd)**

Input	*Definition*
	o Emergency response o Other network maintenance • Other costs: o Meter reading o Customer service o Advertising & marketing o Full retail contestability o Other operating costs (specify items > 5% total opex) • Public lighting • Total opex Corporate overhead costs should be allocated to the relevant categories. Additionally, the following items are required: • Opex costs associated with the higher level transformation step where there are two transformation steps before the distribution level transformation (eg 132 kV to 66 kV and then 66 kV to 33 kV). This opex cost should include the higher step zone substation costs and the costs of operating and maintaining subtransmission lines upstream of the higher level step. • An estimate of the opex costs that would be associated with customer contributed assets that are operated and maintained by the customer (eg transformers owned by high voltage customers) if the operation and maintenance were provided by the distributor (please describe basis of estimation).
Direct employees	Number of full–time equivalent employees in operating and maintenance activities (including shared overhead allocation). Employee time spent on capital construction projects is to be excluded.
Direct labour cost	Labour cost (including on–costs) of employees in operating and maintenance activities (including shared overhead allocation). Cost of time spent on capital construction projects is to be excluded.
Line length by voltage level	As for outputs but with the addition of dedicated circuits for public lighting supply or control to be listed separately. Also, for networks with two transformation steps before the distribution level transformation (eg 132 kV to 66 kV and then 66 kV to 33 kV), subtransmission lines upstream of the higher level step to be listed separately.
Installed transformer capacity	MVA of transformer capacity for the following categories: • Zone substation capacity where there are two transformation steps: o First step (eg 132 kV to 66 kV or 33 kV) o Second step (eg 66 kV or 33 kV to 22 kV or 11 kV) • Zone substation capacity where there is a single transformation step (eg 132 kV or 66 kV to 22 kV or 11 kV) • Distribution transformer capacity owned by the distributor • Distribution transformer capacity owned by high voltage customers

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Table 3: **Distribution Input Measure Definitions (cont'd)**

Input	*Definition*

Optimised replacement cost by nature of asset	Optimised replacement cost (or replacement cost if ORC is unavailable) in current prices for:
	• Overhead lines including:
	    o Subtransmission lines upstream of the higher level step for networks with two transformation steps before the distribution level transformation
	    o Other subtransmission lines
	    o Distribution lines
	    o Dedicated circuits for public lighting supply or control
	• Underground cables including:
	    o Subtransmission cables upstream of the higher level step for networks with two transformation steps before the distribution level transformation
	    o Other subtransmission cables
	    o Distribution cables
	    o Dedicated circuits for public lighting supply or control
	• Zone substations and transformers including:
	    o First step transformation where there are two transformation steps before the distribution level transformation
	    o Other zone substations
	• Distribution transformers owned by the distributor
	• Distribution transformers owned by high voltage customers
	• Other assets including:
	    o Meters and metering equipment
	    o Communications equipment
	    o Land and buildings
	    o Other items not elsewhere included

Depreciated optimised replacement cost by nature of asset	DORC in current prices for the same asset categories as listed above under ORC
Capital expenditure by nature of asset	Capex in current prices for the same asset categories as listed above under ORC
Asset life by nature of asset	Estimated average serviceable total lifetime and residual life in years for the following asset categories: • Overhead lines • Underground cables • Transformers • Other capital

3.1.1 Operating and maintenance expenditure

URF (2002, pp32–35) provides a detailed set of definitions for the coverage of operating and maintenance expenditure for distribution businesses and of each of the categories listed in table 3. In this report we adopt the same definitions. These definitions provide a good basis

for consistent reporting while also containing enough detail to permit a common 'cut' of activities to be taken to allow like–with–like comparisons. The two additional opex items listed in table 3 are required to allow consistent coverage across distributors and will be discussed further below in section 3.1.3. The URF (2002) description of the main opex categories is reproduced below for convenience.

Operating expenses

The operational costs associated with the operation of the network including, but not restricted to:

- the staffing of the control centre(s)
- operational switching personnel
- outage planning personnel
- provision of authorised network personnel
- demand forecasting
- procurement
- logistics and stores
- information technology (IT) costs attributable to network operation
- insurance costs
- land tax costs.

Maintenance expenses

All expenditure relating to the inspection of distributor's poles and/or lines including subtransmission, distribution and customers' high voltage lines.

Maintenance and repair

- Line and pole maintenance.
- Maintenance and repair of apparatus on consumer premises.
- Maintenance and repair of substations.
- Maintenance and repair of work depots and buildings.
- Maintenance and repair of tools and equipment.
- Other.

Vegetation management

All expenditure relating to all normal tree cutting, undergrowth control and waste disposal connected to line clearing including coordination and supervision of vegetation control work. Emergency work must not be included.

Emergency response

All expenditure relating to the work incurred where supply has been interrupted or assets damaged or rendered unsafe by a breakdown, making immediate operations and/or repairs necessary.

Other

This includes:

- fire mitigation (excluding vegetation management)
- field training
- insurance
- sundries
- any other costs.

If any component of this category exceeds five per cent of total operating costs a description and dollar value of the component must be specified.

Meter reading costs

All expenditure incurred in the carrying out of meter reading activities.

Customer service

The costs of providing the following services to distribution customers include:

- facilitating the reporting to the distribution business of network faults and safety hazards, and complaints about the quality and reliability of supply
- responding to queries on new connections, disconnections and reconnections
- responding to queries on improving power factor or load factor.

Call centre costs and customer information system (CIS) operating costs that are caused by the provision of the above services are included.

Excluded from this cost category are:

- costs associated with account inquiries

- costs associated with field activities such as meter repairs, supply connection and line repairs
- responding to general inquiries that are non-network related
- undertaking any work, beyond recording the query and answering questions, associated with new supply connections that proceed, or improving the power factor or load factor.

Advertising/marketing

Advertising and marketing activities attributable to the provision of distribution services, including:

- providing information to customers, and conducting promotional activities to improve the use of the network assets by improving the power factor or the load factor
- providing contact telephone numbers for fault reporting, for example through bill inserts
- publicising reliability targets and communicating with network customers on reliability matters
- development of network tariffs
- communicating with customers on distribution matters, for instance, providing notice of planned interruptions
- educating the public on network-related electrical safety
- activities arising from the distribution business' obligations about the quality of supply.

Excluded from this cost category are:

- brand advertising
- corporate image making
- corporate/community sponsorships and donations
- communication internal to the business
- research and analysis of other distribution businesses
- contact with any Ombudsman
- advertising of retail services.

Full retail contestability costs

Operating costs attributable to the distribution business associated with transferring retail customers from franchise to contestable tariffs. Such costs include:

- the cost of establishing an interface with the centralised customer transfer system
- the cost of adjusting internal processes and systems
- full retail contestability project management costs
- additional operating expenditure, such as those costs associated with transfers.

Other operating costs

This category includes all other costs that are incurred in the provision of distribution services. For example, billing and revenue collection and regulatory costs will be included in this category.

If any component of this category exceeds five per cent of total operating costs, the description and dollar value of the component must be provided.

Public lighting

Services to provide for the lighting of public places, and in particular:

- the operation of public lighting assets, including handling inquiries and complaints about public lighting, and dispatching crews to repair public lighting assets.

Direct labour quantity and cost

As well as the URF (2002) opex material reproduced above, we have also suggested in table 3 collecting data on directly employed full–time equivalent numbers and labour costs (including on–costs) of staff engaged on operating and maintenance activities (including an allocation of shared overheads). While this information would not be used directly in the calculation of TFP indexes at this stage (as the labour inputs are subsumed within overall opex), it provides the most robust measure of labour inputs and may facilitate future partial productivity comparisons of directly employed labour. Care would, of course, have to be taken in any such comparisons to allow for differences in the range of activities undertaken and the extent of contracting out.

Opex quantity

The URF (2002) coverage and definition of opex reproduced above relates to the nominal or current price value of opex. We also need a corresponding quantity of opex inputs for use in calculating TFP. Given that opex covers a diverse range of inputs it is not possible to use a direct quantity measure of this input but rather we need to derive an indirect quantity by deflating the value by an appropriate price index to convert the series to real or constant price terms. Distributors are unlikely to be able to supply useful information on the average price they face for their opex inputs. Rather, the use of an appropriate proxy index such as the GDP

deflator or a producer price index complied by the Australian Bureau of Statistics (ABS) is likely to provide a better option.

3.1.2 Capital inputs

There are a number of different approaches to measuring both the quantity and cost of capital inputs. The quantity of capital inputs can be measured either directly in quantity terms (eg using measures of line length and transformer capacity) or indirectly using a constant dollar measure of the value of assets. Both approaches have their pluses and minuses.

Some analysts have argued that measuring the quantity of capital by the deflated asset value or indirect method provides a better estimate of total input as it better reflects the quality of capital and can include all capital items, not just lines and transformers. There are two potential problems with this approach. Firstly, it requires the asset valuations to be completely consistent across organisations and over time. This will be unlikely to be the case across jurisdictions within Australia where there is currently a mixture of valuation approaches including regular revaluations and roll–forward of valuations close to a decade old. Secondly, approaches using the capital stock to reflect the quantity of inputs usually incorporate some variant of either the declining balance or straight line approaches to measuring depreciation. Distribution business assets tend to be long lived and to produce a relatively constant flow of services over their lifetime. Consequently, their true depreciation profile is more likely to reflect the 'one hoss shay' or 'light bulb' assumption than that of either declining balance or straight line. That is, they produce the same service each year of their life until the end of their specified life rather than producing a given percentage less service every year. In these circumstances it may be better to measure the quantity of capital input by the physical quantity of the principal assets.

Against the direct quantity approach are its inability to pick up quality differences and the close relationship of the measures of lines capital on the input side and system capacity on the output side.

It is desirable to include at least four capital input categories including overhead lines, underground cables, transformers and other capital in a distribution TFP measurement exercise. The quantity of overhead and underground lines can be measured directly by their capacity (eg in MVA kilometres) while transformers can be measured by their MVA rating. The quantity of the other capital input category usually has to be measured indirectly given its diverse composition and its cost will be deflated by a relevant capital price index. It is important to differentiate between overhead lines and underground cables in forming capital measures because of the very large difference in the cost of putting cables underground compared to lines overhead. However, offsetting the higher capital costs of undergrounding

are usually lower opex costs and superior reliability which needs to be taken account of on the output side.

In table 3 we have adopted the approach of collecting information that would enable either a direct quantity or indirect deflated value method of measuring capital quantity to be used. Collecting line length by voltage level using analogous voltage categories to those nominated in table 1 for distribution outputs and differentiated by overhead versus underground again permits direct quantity measures such as MVA–kilometres to be formed for lines and cables inputs. We include a request for dedicated public lighting circuits to be separately identified to allow a wider input specification which includes public lighting inputs. We also specify transformer capacity at both the zone substation and distribution levels to allow a direct measure of transformer inputs to be formed. The distinction between two step and one step transformation before the distribution level transformation is made to potentially allow more like–with–like comparisons which will be addressed in section 3.1.3.

To enable use of the indirect deflated value method for measuring capital input quantities we request asset optimised replacement cost (ORC) as the most appropriate measure of the capital stock. This abstracts from differences in average asset age, which will influence DORC based comparisons. We again ask for a break–up of lines, cables and transformer ORC that will facilitate like–with–like comparisons.

The annual cost of using capital inputs can also be measured either directly by applying a formula which includes an estimated depreciation rate, a rate reflecting the opportunity cost of capital and other factors such as taxation effects to the value of assets or indirectly as the residual of revenue less operating costs. Estimating productivity using a direct estimate of the cost of capital is more consistent with the underlying producer theory where an ex ante measure is required. The appropriate value of assets to use in the direct approach is now the current market value of the assets, which is usually proxied by the depreciated optimised replacement cost (DORC). Consequently we have listed a corresponding break–down of DORC by nature of asset in table 3.

To allow construction of a time–series of asset values we have requested information on capital expenditure (capex) by the corresponding nature of asset. This allows us to use the perpetual inventory method to roll asset values forwards and backwards using additions to the capital stock (ie capex) and estimates of depreciation. To allow reasonable rates of depreciation to be formed we have asked for information on estimated average asset lifetimes and the residual lives of installed assets for each of the four main asset types.

The main difference between the asset value and capex data requested in table 3 and that proposed by URF (2002, pp30-31) is that we request:

- disaggregation of lines values into overhead and underground components;
- separate identification of dedicated circuits for public lighting supply or control;
- separate identification of the first stage transformation step and associated upstream subtransmission lines in networks with two transformation steps before the distribution transformation level; and,
- inclusion of distribution transformers owned by high voltage customers.

Data on capital stock prices are again best derived from ABS capital price indexes. The annual user cost of capital can be constructed with varying degrees of sophistication. The main refinements to the basic formula relate to allowance for tax effects. This usually requires additional information on debt ratios and the rate of depreciation allowable for tax purposes. However, we have not included these items in table 3 as they are more likely to be relevant to more mature markets where there has been a long history of private ownership. Given the current stage of development of the Australian market, relatively simple measures of the user cost of capital such as that used by Meyrick and Associates (2003a,b) will be more appropriate.

3.1.3 Achieving consistency in coverage

There are a number of areas where the boundaries between distribution, on the one hand, and transmission and retail on the other can differ between jurisdictions. The extent of regulatory coverage can also differ between jurisdictions and customer provided assets can further complicate the picture. This raises a number of issues regarding the desirability of having a consistent coverage of activities across all distributors included in a TFP comparison exercise.

The consistency of coverage issue will have a proportionately greater effect on the input side of the TFP calculation. This is because distributors' outputs will usually be measured as some combination of throughput, customer numbers, system capacity and peak demand regardless of differences in boundaries. However, the location of the boundaries between transmission, distribution and retail will affect the extent of nearly all measured inputs which are attributed to distribution.

The importance of having as similar a coverage as possible will vary with the extent of information being taken from the comparison and the measurement technique being used. If the comparison is being used to obtain information on comparative productivity growth rates then having a completely consistent coverage will be less critical than if information on productivity levels as well as growth rates is being sought. If productivity levels are being compared then having a consistent coverage of activities will be critical otherwise

distributors who cover a wider range of activities may be unfairly penalised for appearing to use more inputs and, hence, be less efficient than distributors who cover a narrower range of input activities. Having consistent coverage will be more critical in productivity studies using cost function analysis and multilateral TFP indexes than it will in studies applying time series TFP indexes to each distributor in isolation.

The main area where boundary differences can affect TFP level comparisons is the dividing line between transmission and distribution. Here different historical developments between jurisdictions have led to different boundaries and different power transformation structures within distribution. Consequently, distributors who take their power from transmission service providers at lower voltages (eg 66 kV) and, hence, have less subtransmission network and/or who are able to transform power to distribution voltages in one step rather than multiple steps will be advantaged in efficiency comparisons. This is because their distribution network will appear to be using fewer inputs to deliver the same output. However, this may in part reflect the fact that some inputs being classed as belonging to distribution in other jurisdictions are classed as being outside the distribution network for this distributor. Similarly, the ability to have a single rather than multiple transformation steps may reflect the historical development of the system and be largely outside the control of current managers.

To address this issue we have requested separate data on the first transformation step and associated upstream subtransmission lines for systems with two transformation steps before the final distribution transformation. This would allow this part of their activities to be potentially excluded from their opex and capital input coverage and, hence, provide a more like–with–like comparison with single step networks. While imperfect, the option of excluding the first step of two step networks appears preferable to the alternative of trying to bring in equivalent upstream functions from single step networks that may be classed as part of the transmission system in that jurisdiction.

Another area of ambiguity is assets owned by the customer. Some large customers may own their distribution transformers while the DB owns those supplying other customers. Ideally we need to have all the distribution transformers included regardless of who owns them to allow like–with–like comparisons. Consequently, we have requested the separate identification of the opex cost associated with the distributor operating and maintaining assets that may currently be owned and maintained by the customer as well as their capacity and asset value. This would allow these assets to be included in the distributors' input coverage to permit like–with–like comparisons with systems where the there are no customer owned transformers. Where assets such as lines and cabling in new subdivisions are provided by the developer (but usually then gifted to the distributor) they should be treated as part of the distributor's assets for TFP measurement.

Other potential boundary issues relate to metering and public lighting. Provision and reading of basic metering is now generally recognised as the responsibility of the distributor and should not cause comparability problems. However, problems could arise if the degree of retail contestability varies significantly between jurisdictions, as contestable customers must have more sophisticated meters capable of being read remotely. The provision of these meters is then the responsibility of the retailer. In case this disparity in the degree of retail contestability becomes significant in the future we have requested separate data on opex associated with metering and on metering assets. This could allow this function to be removed from the input coverage if necessary.

Public lighting is a joint product that is provided by distributors in conjunction with their distribution activities to individual customers. While there are community service obligation arrangements regarding the pricing of public lighting in some jurisdictions and regulatory treatment varies, it would be preferable to treat the provision of public lighting as part of the distributor's normal activities for TFP measurement purposes. However, to keep future options open we have asked for separate identification of opex associated with public lighting (as was done by URF 2002) and for lines dedicated to providing and controlling public lighting. This would allow public lighting to be removed from TFP coverage, if desired.

3.2 Electricity transmission

The key input measures required for TFP measurement for a transmission network service provider are:

- Total operating and maintenance expenditure by category (excluding all capital costs and capital construction costs)
- Number of full–time equivalent employees in operating and maintenance activities (including shared overhead allocation)
- Labour cost (including on–costs) of employees in operating and maintenance activities (including shared overhead allocation)
- Line and cable length by voltage level
- Installed transformer capacity by type
- Optimised replacement cost by nature of asset
- Depreciated optimised replacement cost by nature of asset
- Capital expenditure by nature of asset
- Asset life by nature of asset (overall and residual)

Definitions of the transmission input measures are presented in table 4 and discussion of the rationale for including each follows.

Table 4: **Transmission Input Measure Definitions**

Input	*Definition*

Opex by category	The costs of operating and maintaining the network (excluding all capital costs and capital construction costs) by the following categories:
	• Network operating costs
	• Network maintenance costs:
	    o Inspection
	    o Maintenance & repair
	    o Vegetation management
	    o Emergency response
	    o Other network maintenance
	• Other operating costs (specify items > 5% total opex)
	• Total opex
	Corporate overhead costs should be allocated to the relevant categories. Additionally, the following item is required:
	• An estimate of the opex costs that would be associated with end–user contributed assets that are operated and maintained by directly connected end–users (eg transformers) if the operation and maintenance were provided by the TNSP (please describe basis of estimation).

Direct employees	Number of full–time equivalent employees in operating and maintenance activities (including shared overhead allocation). Employee time spent on capital construction projects is to be excluded.
Direct labour cost	Labour cost (including on–costs) of employees in operating and maintenance activities (including shared overhead allocation). Cost of time spent on capital construction projects is to be excluded.
Line length by voltage level	Same as for outputs.
Installed transformer capacity	MVA of transformer capacity for the following categories: • Transmission substations (eg 500 kV to 275 kV) • Terminal points • Transformer capacity for directly connected end–users owned by the distributor • Transformer capacity for directly connected end–users owned by the end–user • Other (please specify)
Optimised replacement cost by nature of asset	Optimised replacement cost (or replacement cost if ORC is unavailable) in current prices for: • Overhead lines • Underground cables • Transformers owned by the TNSP • Transformers owned by directly connected end–users

Cont'd overleaf

Table 4: **Transmission Input Measure Definitions (cont'd)**

Input	*Definition*

	• Other assets including:
	  o Communications equipment
	  o Land and buildings
	  o Other items not elsewhere included

Depreciated optimised replacement cost by nature of asset	DORC in current prices for the same asset categories as listed above under ORC
Capital expenditure by nature of asset	Capex in current prices for the same asset categories as listed above under ORC
Asset life by nature of asset	Estimated average serviceable total lifetime and residual life in years for the following asset categories: • Overhead lines • Underground cables • Transformers • Other capital

The input specification for transmission in table 4 follows broadly the same structure as that for distribution in table 3. Again there are two broad input categories – opex and capital inputs. In opex we have used a similar structure to that of URF (2002) but modified to remove the metering and customer service functions found in distribution. We have included a request for an estimate of the opex that would be associated with operating and maintaining end–user owned and maintained assets that would normally be provided by the TNSP to allow more like–with–like comparisons.

Data on the full–time equivalent numbers and costs of directly employed staff engaged in operating and maintenance activities are again requested as these are the most robust labour data likely to be available. However, this information would not be used in the TFP calculation and is requested simply to keep options open regarding future partial productivity comparisons.

Capital input quantities can again be measured either directly by using measures of physical quantities or indirectly using deflated asset values. The physical quantity of lines and cables are again based on the same data for line and cable length by voltage class as requested for transmission outputs in table 2. Application of agreed conversion factors would convert this data to an MVA–kilometres measure. A distinction is again made between overhead lines and underground cables to capture the relatively higher cost of undergrounding.

Transformer capacity in MVAs would again form the basis of a physical measure of transformer capital quantity. We ask for separation into transmission substations (which convert very high voltages in some networks to high voltage for further transmission) and

terminal points to allow potential identification of the impact of having more transmission voltages and transformation steps within the network. We also ask for transformer capacity associated with directly connected end–users, including any capacity that may be owned by the end–user. The latter will allow more like–with–like comparisons between networks.

To allow the option of using the indirect approach to measuring capital quantities, we request data on the optimised replacement cost of key asset categories, including transformers that may be owned by directly connected end–users. We also request corresponding DORC and capex data to facilitate construction of capital user costs and the roll forward of asset values, respectively. Information on the average overall lifetime of key asset categories and corresponding average residual lives will facilitate calculation of an appropriate depreciation rate to be used in the user cost and any asset value roll forwards.

Just as differing boundaries between transmission and distribution across jurisdictions have the potential to impact on distribution productivity level comparisons, then they have a corresponding (but opposite) potential to impact on transmission productivity level comparisons. However, while there is potential to address this on the distribution side by taking a similar 'slice' from distributors who cover a wider range of subtransmission functions and/or have multiple transformation steps before the distribution transformation level, there is limited to scope to try and put TNSPs on a completely similar footing. Consequently, we do not request additional data to support this. Rather, TFP comparisons that look at transmission TFP levels will require a more detailed assessment of the network characteristics of each TNSP. Comparisons of TFP growth rates between TNSPs can, however, be readily made using the data specified.

4 OPERATING ENVIRONMENT VARIABLES

Operating environment conditions can have a significant impact on transmission and distribution costs and productivity and in many cases are beyond the control of managers. Consequently, to ensure reasonably like–with–like comparisons it is desirable to 'normalise' for at least the most important operating environment differences. Likely candidates for normalisation include energy density (energy delivered per customer), customer density (customers per kilometre of line), customer mix, the degree of undergrounding, and climatic and geographic conditions. With the exception of climatic and geographic conditions, all these operating environmental variables can be derived from the data requested above under outputs and inputs.

Energy density and customer density are generally found to be the two most important operating environment variables in distribution normalisation studies (see Meyrick and Associates 2003a,b). Being able to deliver more energy to each customer means that a

distributor will usually require less inputs to deliver a given volume of electricity as it will require less poles and wires than a less energy dense distributor would require to reach more customers to deliver the same total volume.

A distributor with lower customer density will require more poles and wires to reach its customers than will a distributor with higher customer density but the same consumption per customer making the lower density distributor appear less efficient unless the differing densities are allowed for. Most studies incorporate density variables by ensuring that the three main output components – throughput, system capacity and customers (or connections) – are all explicitly included. This means that distributors who have low customer density, for instance, receive credit for their longer line lengths whereas this would not be the case if output was measured by only one output such as throughput.

Climatic and topographic/geographic factors may be important operating environment factors for some transmission and distribution networks. The temperature and wind conditions in the area traversed by the transmission or distribution line will influence the effective capacity rating of the line without causing overheating or excessive sagging. The hotter and stiller the ambient conditions, the lower will be the rating associated with a given line construction so that a line of greater apparent capacity might be required to achieve the required actual rating. Conversely, the weight of snow or ice loading may result in excessive sagging in alpine regions and again limit the actual line capacity. Terrain will also be an important driver of transmission and distribution costs with more rugged terrain increasing the costs of construction and requiring more inputs for maintenance. For instance, in steep, inaccessible terrain maintenance crews may have to be flown in by helicopter or snow-cats may be required in alpine regions. Similarly, transmission and distribution lines through bushfire prone areas may require higher construction standards and/or be subject to more outages when fires occur than lines through more benign environments.

Obtaining useable data on climatic and geographic factors is usually problematic as they differ markedly across most TNSPs' and distributors' territories. This is particularly the case for rural networks where these factors are likely to be more important. Furthermore, in practice the ability to include a wide range of operating environment variables in econometric studies is usually limited by multicollinearity between these variables and the main output variables and/or a lack of variation in the variables over time. Consequently, we do not request additional data on climatic and geographic factors at this point in time. Rather, including the main density and other variables derived from the requested output and input data will capture the main operating environment characteristics likely to affect costs for the majority of distribution networks. Transmission TFP growth rate comparisons can generally be made without the need to adjust for climatic and geographic conditions.

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