AURORA ENERGY

A comparative analysis: Aurora Energy's Network cost structure

Benchmark Economics

May 2011

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Key findings

In determining the building block revenue for Aurora Energy (Aurora) for the period 2012-2017, the National Electricity Rules (NER) require the Australian Energy Regulator (AER) to accept Aurora's forecast operating expenditure if it meets two key criteria. Operating expenditure should reflect the efficient cost of achieving the operating expenditure objectives and also the costs required by a prudent operator in the same circumstances as the relevant distribution network service provider (DNSP).

Analytical framework

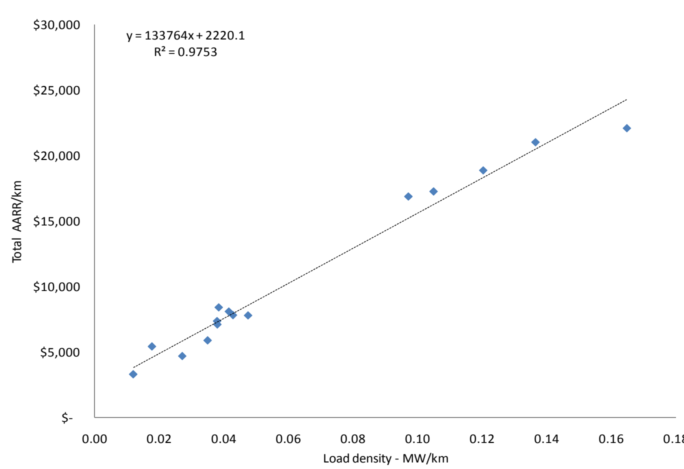
Benchmark Economics has been commissioned by Aurora to assess its operating expenditure against these criteria. Key findings from this analysis include:

Operating expenditure varies notably among the Australian DNSPs reflecting the wide range of business conditions within which they operate. By quantifying the influence of these conditions on comparative costs, it is possible to assess with confidence the relative efficiency of the DNSPs

Key cost drivers for comparing electricity distribution networks are load density (peak demand per km), customer class (average kWh consumption per connection) or load factor (average demand to peak demand), and the age and condition of the network.

Load density offers statistically significant explanation for almost all variation between expenditure outcomes for Australian DNSPs (Figure A). It provides a robust basis for estimating efficient and prudent operating expenditure.

Figure A: Load density and total costs (AARR) per km



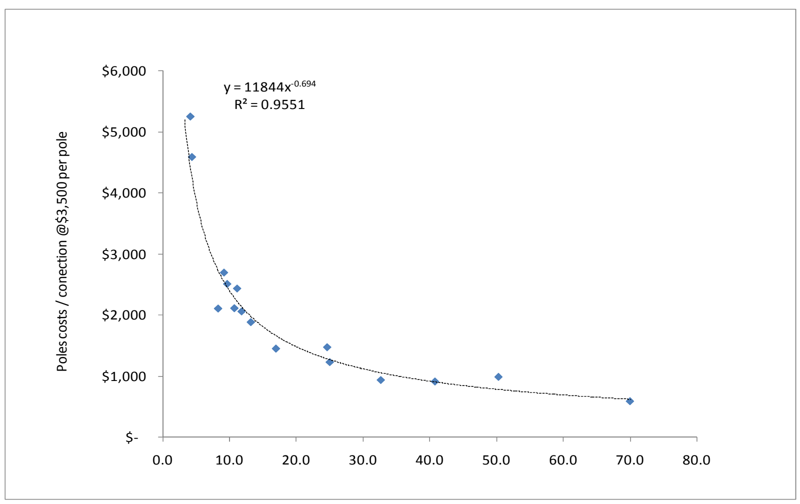
Any variation around the trend typically forms only a small proportion of the cost differences between DNSPs – and is explained by factors such as asset age, load growth, or accounting practices.

Load density is linked to costs through the assets required to provide the physical connection to end-users. These, in turn, are determined by the physics of energy flows. That is, technical conditions drive the choice of different types of assets for different types of load with commensurate variations in cost outcomes for the DNSPs.

Cost analysis that does not take to account the physical realities of electricity distribution networks may draw misleading conclusions from the analysis.

For example, the downward slope in the cost curve in Figure B, which plots connection density against pole costs per connection for the Australian DNSPs, reveals that high density networks have relatively lower per connection costs because they share resources and so fewer poles (and associated assets) are required to provide the connection.

Figure B Pole costs per connection and connection density



A position at the high or low end of this cost curve does not provide any evidence, per se, of the relative efficiency of the networks. The slope of the trend line in Figure B explains that 95 per cent of the variation in pole costs per connection is related to differences in connection density. Relative efficiency of a DNSP is measured by its position above or below the trend line, not whether it is at the high or low end of the curve itself.

Estimates:Efficient and prudent expenditure

2009: Efficient and prudent operating expenditure for Aurora for the current price set period (represented by data for 2009) is estimated at $74.6 million in 2009 dollars with a +/- 10 per cent range prediction range.

Regulated expenditure was $71.7 million and actual expenditure was $66.4 million. (See Table 13 for details).

Prudent operating expenditure for 2009 would also include an additional $83M, or 3.14 per cent of the asset base valued at $2009 replacement cost, to take account of the ageing of the asset base and the additional operating expenditure required to maintian the netork in good condition.

This age related estimate, at management discretion, could be off-set by refurbishment or replacement expenditures.

2013-15: Efficient and prudent operating expenditure for Aurora for the forecast pricing period (represented by an average of the years 2013-15) is estimated at $87.3 million in 2009 dollars with +/- 10 per cent range prediction range. (See Table 16 for details).

An amount similar to that estimated in the 2009 analysis to take account of the ageing asset base will be required annually for the five year regulatory price period if the older assets are not replaced. That is, an additional amount of around $83M for each year that the older assets and retained in service.

Capital expenditure: Capital expenditure was examined to assess whether there was any trade-off with operating expenditure. We find the regulated capital expenditure allowance in 2009 and 2013-15 for Aurora is in line with its business conditions and industry trend investment levels. Accordingly, we accept that capital expenditure does not include any off-set for higher/lower operating and maintenance expenditure.

Asset age: Capital expenditure derived from the age profile of Aurora's asset base indicates a probable replacement spend of $21.5M in 2009 and $28.7M in 2013 rising to $35.5M in 2017.

All estimates for operating and capital expenditures are in $2009 dollars.

1 Introduction

The Australian Energy Regulator (AER) is undertaking a review to determine the regulated revenue for the electricity distribution system of Aurora Energy (Aurora) for the period 2012-2017. This will be the first determination of revenues for Aurora by the AER, which assumes responsibility for regulating Tasmania's electricity network businesses on 1 July 2012.

Aurora has commissioned Benchmark Economics to analyse its network structure and operating conditions to determine efficient and prudent operating expenditure assessed against the criteria listed in the National Electricity Rules (NER) Clause 6, Part C. The analysis is presented in two parts; a review of Aurora's current expenditures, represented by the year ending June 2009, and a review of forecast expenditures for the ensuing regulatory control period, represented by an average of the years ending June 2013-2015.

The framework for economic regulation of distribution services is set down in the NER Chapter 6, Part C, Building block determinations for standard control services. The building blocks consist of a rate of return on, and of, capital, and forecast operating expenditure. The capital-based building blocks are determined according to the weighted average cost of capital (clause 6.5.2) and depreciation schedules (clause 6.5.5). Operating expenditure, the third building block, should reflect:

- the efficient costs of achieving the operating expenditure objectives; and
- the costs that a prudent operator in the circumstances of the relevant distribution network service provider would require to achieve the operating objectives; and
- a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

Standard estimation models such as the CAPM, WACC, and depreciation schedules, prescribed by Chapter 6 for the capital based building blocks are not available for determining operating expenditure, the third building block. To bring similar rigour to setting operating expenditures, regulators both in Australia and overseas, have adopted measurement techniques largely framed by economic analysis.

Ongoing refinements have brought some methodologies to a high degree of complexity. Yet actual outlays can still exceed regulatory estimates of efficient expenditure, in some instances by more than double the regulated allowance. That regulators generally accept, in retrospect, the overspend suggests the higher costs were not due to any operating inefficiencies. The continuing gap between prospective and retrospective measures of 'efficient' cost raises questions about the efficacy of the network cost models.

Developed within the context of economic regulation, network cost models have focused largely on economic interpretations of network costs. But as Professor Turvey, Chairman of the Centre for the Study of Regulated Industries has observed, "the efficiency of a business is a matter of whether it does what it does as well as it should do it"[1]. That is, the specification of credible network cost models must be based on what the network business does - the specific features of the network business rather than a generic approach based on general economic theory. However, a review of estimation methodologies suggests analysis of the production process for electricity distribution networks has not paralleled the evolution of the generic economic cost models. In one of the better analyses of network efficiency, Neuberg[2] observed:

> *"Hopefully, someday functional form choice will grow out of a heuristic/ theoretic investigation of the actual production process being modelled."*

30 years since this was written the network production process remains outside the majority of cost models. Informed by precedent, rather than a practical understanding of what a network does, cost models have not even been able to reach agreement on the basic question of what does the network produce? Some variables have been used interchangeably either as inputs or outputs, while energy conveyed (MWh) is widely used as an output when it is actually a network throughput. Indeed, the term distributor used for the network part of the electricity supply chain should provide a strong clue as to what a network does.

Summing up efficiency assessments for the Economic Regulators Regional Association in Eastern Europe, the analysts Kema International[3] observed that:

> *"There is no agreement in either the literature or practice as of how inputs and outputs should be selected in principle. This mainly depends on the existence of a proved economic relationship between inputs and outputs, which on most empirical occasions is unfortunately not available…Therefore, the construction of input and output-based models, as well as their specification, is based on empirical analysis and try-and-error (sic) specifications."*

To integrate technical aspects into the estimation process, some countries, including Chile and Spain, have turned to complex engineering cost models. Based on 'ideal' or greenfields network configurations these models have tended to raise more questions than answers. As network design evolves in response to changes in location and demand of end-users, actual network configurations can never achieve the design simplicity, and hence cost efficiency, of a greenfields 'ideal' network. There remains, nonetheless, a need to integrate technical factors into network cost models.

One such approach is available. As networks are capital intensive (capital charges are around 70 per cent of annual revenue), the asset base presents a

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1 Turvey, Ralph. "On network efficiency comparisons: Electricity distribution", *Utilities Policy*, 2006 Vol. 14 (2) 103-113

2 Neuberg, Leland Gerson, 1977 "Two issues in the municipal ownership of electric power distribution", *Bell Journal of Economics*.

3 Kema International B.V. *"Efficiency factor's determination (X-factor)",* Report to the ERRA Tariff/Pricing Committee, 2006

simple and direct link between the underlying technical factors and network expenditures – a shortcut between the bottom-up engineering models and the top-down econometric analyses. Network costs will embody the assets necessary to connect end-users and meet their demand; with the assets, in turn, reflecting the physics of energy flows.

This link was recognised in an earlier version of the NER. In Version 17 of the NER, at Schedule 6.3, the Categories of Distribution Cost[4].Schedule stated distribution system costs may be formed from the aggregate annual revenue requirement (AARR), which can be separated into four components:

> *"…costs which relate to the provision of assets to provide access to overall distribution service…cost of providing assets which are fully dedicated…cost of assets which are shared…costs which relate to the provision of services to Embedded Generators…"(Emphasis added)*

Simply put, costs to be charge by DNSPs were to be based on the AARR, which in turn was based on system assets. Schedule 6.3 even provided a series of diagrams of system assets illustrating typical distribution cost classes based on asset requirements. This was a useful guide. It recognised that as a capital intensive industry, costs would largely be a function of the asset base. Next, it made clear different types of customers would face different charges since their asset requirements would vary.

Schedule 6.3 of Version 17 of the NER has been superceded; version 43 is the latest available and does not contain a similar stipulation. It does, however, in Part F clause 6.15.2 refer to cost allocation principles and at clause 6.15.2(3)(i) states costs will be directly attributable to the provision of the service. While less prescriptive than Schedule 6.3 in Version 17, this clause implies allocated costs are to be based on system assets. If costs reflect differing operating conditions then, it can be inferred, comparative cost comparisons must also have regard to the same conditions.

- To facilitate a rigorous assessment of comparative cost, Benchmark Economics has developed a network cost structure model that:
- identifies key network cost drivers, including interrelationship with the asset base and the underlying physics of energy flows;
- quantifies links between these factors and cost outcomes; and
- provides statistical estimates of prudent expenditures appropriate for network businesses with disparate operating environments – a measure of efficient operation.

This report is structured as follows:

4 National Electricity Rules (Version 17), Chapter 6, Schedule 6.3 Economic Regulation of Distribution Services

Chapter 2 discusses the notion of efficient cost in the context of incentive-based regulation, and draws attention to the distinction between expenditure and cost.

Chapter 3 Defines benchmarking, highlights its importance in the decision making process, and discusses the theoretical underpinnings in the regulatory context.

Chapter 4 presents a brief digression on regression analysis.

Chapter 5 addresses data issues.

Chapter 6 analyses network cost structures and details the cost model used in this report for assessing comparative cost performance.

Chapter 7 analyses network cost drivers and identifies major business conditions affecting network costs. It quantifies the linkages between the cost drivers and total network costs – defined as the smoothed regulated aggregate annual revenue requirement (AARR).

Chapter 8 provides an outline of Aurora's distribution network.

Chapter 9 presents the expenditure analysis for 2009, examining the 'efficiency' of operating and maintenance expenditure for Aurora and estimates the impact on prudent expenditure of its asset age profile

Chapter 10 presents the expenditure analysis for 2012-13. The impact of asset age on prudent capital expenditure is assessed.

2 Efficient cost

2.1 Efficient cost and regulatory framework

Efficient cost entered the regulatory lexicon as a component of the CPI-X incentive-based pricing mechanism introduced at the time of unbundling vertically integrated utilities. Replacing discredited cost-of-service regulation based on a firm's own cost, CPI-X pricing regimes allows firms to increase prices by reference to an external target. In Australia this is the rate of inflation (CPI), less an efficiency factor (X). The objective was to lift productivity by providing the business with an opportunity to earn a higher rate of return if it could further reduce costs below the efficiency target.

The X-efficiency factor may be the regulator's estimate of potential productivity growth, or it may be derived from 'yardstick competition' where an element of competition is introduced by comparing costs against those of similar firms[5].

In the Australian context, the role of efficient cost is formalised in Chapter 6 Part C, of the National Electricity Rules (NER). Setting out the framework for economic regulation of the DNSPs, it details the building block approach for determining the annual revenue requirement. The building blocks are:

- Indexation of regulatory asset base; and
- Return on capital; and
- Depreciation; and
- Estimated cost of corporate income tax; and
- Increments or decrements arising from performance scheme; and forecast operating expenditure; and
- Forecast operating expenditure.

Determination of operating expenditure is to be in accord with objectives, criteria, and decision factors set down in Section 6.5.6.

The objectives to be achieved by the forecast operating expenditure are set down in Section (6.5.6(a) and require expenditure:

- to meet expected demand for the standard control services;
- to comply with regulatory obligations; and
- to maintain quality and reliability and security of distribution system.

Criteria for the AER's acceptance of the DNSP's proposed forecast operating expenditure are set down in Section 6.5.6 (c). The forecast must reasonably reflect the:

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[5] Tilley, Brian and Weyman-Jones, 1999. *"Productivity Growth and Efficiency Change in Electricity Distribution"*, British Institute of Energy Economics – The 1999 BIEE Conference, St. John's College Oxford.

- efficient cost of achieving operating expenditure objectives;
- cost that a prudent operator in the circumstances of the relevant Distribution Network Service Provider would require to achieve the operating expenditure objectives; and
- a realistic expectation of the demand forecast and cost of inputs required.

To assist the AER in its decision making, Section 6.5.6(e) provides ten factors to which it should have regard in making its decision relating to the operating objectives and efficiency criteria. These include:

- Information provided by DNSP;
- Analysis undertaken by the AER;
- Benchmark operating expenditure incurred by an efficient DNSPs over the regulatory control period; and
- Operating expenditure during previous control period.

Drawing these elements together, "efficient cost" can be defined as operating expenditure that would be:

- incurred by an efficient and prudent DNSP;
- operating in the same circumstances as the relevant DNSP;
- expended over the forward regulatory period; to
- provide a standard control service to meet expected demand, maintain quality and reliability of supply, and comply with regulatory obligations.

2.1.1 Distinguishing between expenditure and cost

Chapter 6 Section C discusses not one, but two measures of operating expenditure. While the expenditure objectives refer to operating expenditure – that is – an annual financial flow, the expenditure criteria refer to efficient cost – which is not a flow, but an outlay 'in return for something'[6]. The outlay, for electricity networks, is operating expenditure; the 'something' is the operation and maintenance of the network. Outlays divided by production is the unit cost. Efficiency analysis can only make sense if it addresses the unit cost of production, not the annual flow of operating expenditure which does not inherently contain a specific level of output.

It is assumed the efficiency assessment set down in section 6.5.6(c) of the NER relates to production cost. Once the AER is satisfied that unit cost (expenditure divided by outputs) is efficient it can then proceed to derive an acceptable flow of annual operating expenditure. In practice, however, expenditure flows, operating or capital, have been the focus of efficiency assessments, with little reference to the cost of production. Moreover, there is a tendency to use the terms interchangeably overlooking the distinction.

[6] Penguin Dictionary of Economics, 1984

In lieu of a cost of production measure, regulatory operating expenditure has been calculated as the sum of a basket of financial flows including base year expenditure (revealed cost), real cost and scale escalators, step changes, debt raising costs, and self insurance. For capital expenditure, an activities based approach has been adopted analysing separately the outlays for reinforcement, demand, reliability, environment, SCADA etc. Network output (connections, capacity, or length of line) is largely omitted from both operating and capital expenditure analysis, only appearing with reference to the growth rate for connections as one component of the economies of scale adjustment.

This approach may offer the advantage of a standardized, manageable framework for estimating cost but it obscures the rationale for incentive-based pricing – increasing productivity. Unless inputs and outputs are assessed in tandem it is not be possible to determine which way productivity may be changing. Focusing on the firm's own expenditure tends to regress to a cost-of-service model. Only by relating cost to output, and to external benchmarks, can the regulator assure stakeholders that expenditure increases are efficient and justified; security is not threatened by underspend nor is there wasteful overspend.

Consider the difference in reported increases in regulatory allowances if annual expenditure is converted to unit costs. While the AER reported a 32 per cent increase in regulatory expenditure in Victoria in the five years to 2015, this reduces to an increase of just nine per cent if measured per connection, and a decline of nine per cent if measured per MW of peak demand.

It may be argued the lower increases in unit costs reflect operating efficiencies, however, the regulatory determination stated explicitly the sharply higher expenditures were additional funds to accommodate growth in the network size, real input cost increases, and material changes to the operating environments including changed regulatory obligations.

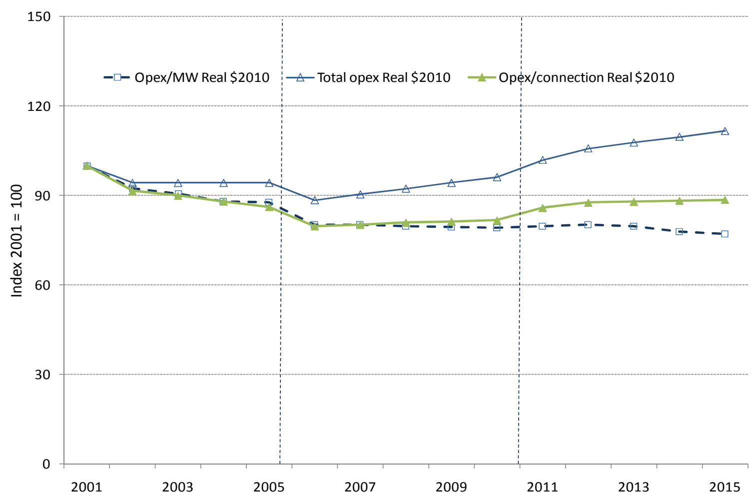
The divergence between expenditure and cost is illustrated in Figure 1, which compares expenditure to the cost-of-production, in real terms[7]. Production costs have been calculated by normalising expenditures against connection numbers and peak capacity provided (MW). While the 32 per cent increase reported in the Final Determination may appear adequate to the task of funding the increase in network size and changes in the operating environment, the more modest increase per connection and the real decline in expenditure per peak demand MW suggest a more constrained financial environment.

Concerns raised by consumer groups at the 32 per cent increase in expenditure allowances could be allayed if, instead, the cost-of-production data were reported. Despite a potential decline of 23 per cent in operating cost per MW of peak demand, between 2001 and 2015, perceptions remain that the higher expenditure allowances reflect only continuing inefficiency. Past experience

7 Data are sourced from the AER Victorian Final Determination, 2010.

demonstrates falling real production costs (operating or capital) eventually undermine the security and reliability of the system, an outcome that could not be welcomed by end-users.

Figure 1.**Expenditure and the cost of production - 2001 - 2015**



2.2 Efficient cost defined

'Efficient' cost, used widely as an objective in regulatory price setting, is an elusive concept. It has been defined in many ways but there remains no standard metric for regulatory purposes.

The NER defines efficient by reference to the cost incurred by an efficient and prudent DNSP, operating in the same circumstances as the relevant DNSP. This explanation is circular; to assess the efficient cost of business B, the AER must first identify an efficient business A. Criteria for identifying business A, the first efficient DNSP, are not provided.

Economics defines efficiency by the manner in which goods and services are produced. It offers several definitions: productive, allocative, and dynamic. For the purpose of the NER and the efficiency test, the most relevant is productive efficiency which requires a given output be produced at minimum cost, short run or long run, time series or across entities. It offers no guidance on identifying the actual minimum cost. Defined in this way, economic efficiency is a concept not a target; it does not provide an economic equivalent to the metrics of the WACC financial market model.

To define efficient cost, the AER has adopted the 'revealed cost' approach of the Essential Services Commission Victoria (ESCV), based on the DNSPs own costs over the preceding regulatory period. Relying on the financial incentives for businesses to lift efficiency, the outcome at the end of each regulatory period is assumed to be an efficient level of base expenditure. This then becomes the starting point for assessing the needs of the business for the forthcoming regulatory control period. Allowances for step changes, cost and scale escalations, debt raising costs, and self insurance are added to the base year costs.

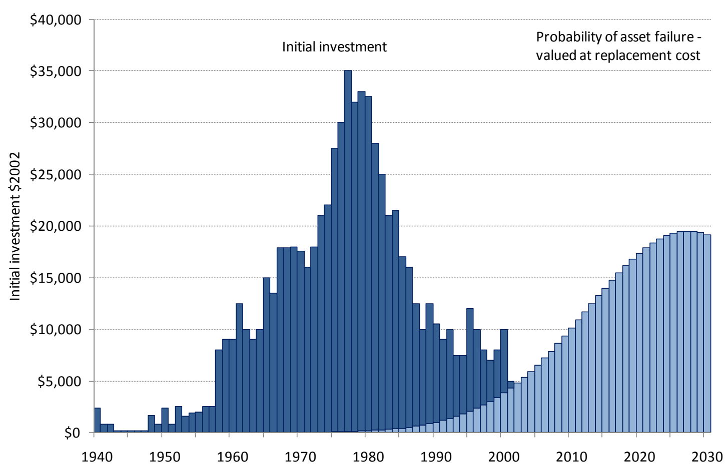
The benefit of this approach is a transparent, standardised framework for estimating efficient cost. But this has been achieved at the cost of a return to internal cost-of-service type regulation; since future expenditures are based on the DNSPs own historic costs rather than external costs. This was not the intention of regulatory reform

2.2.1 Efficient cost and trend analysis

Two assumptions underpin the use of revealed cost or trend analysis for determining forward efficient cos. One, electricity networks are a mature industry with stable expenditures, and, two, base cost plus escalation for scale and inflation, will be sufficient to maintain the integrity of the network over the regulatory period. Step-change costs for material changes in the operating environment are additional to 'business as usual' costs.

Though a mature industry, electricity networks are also capital intensive, with assets that do not last forever, at some time those assets must be replaced. Average asset lives of 50 years ensure a distinct cycle of investment and replacement[8] (Figure 2).

Figure 2.**Typical investment roll-out and probability of failure rate -**



Source: Benchmark Economics

As an emerging technology, network investment expanded rapidly between 1950 and 1980, followed by a relatively stable period as investment slowed to a more moderate pace reflecting load growth. But as the original assets reach the end

[8] Replacement cycle is based on probability of failure of the initial asset, proxied in Figure 2 by the replacement cost of the asset. Probability of failure curve is based on a Weibull distribution.

of their useful lives, the cost of maintaining or replacing aged assets rises year on year, and the past can no longer present a true guide to the future.

In the years between 1990, when economic regulation was introduced, and 2010, estimated annual replacement investment increased by around 400 per cent for Australian DNSPs, or around 7 per cent compound per year, boosting sharply annual investment required[9]. In the first decade of economic regulation, this additional expenditure was largely below the horizon, and regulated operating and capital expenditures often fell short of the investment required to maintain or replace ageing assets. Eventually, this shortfall emerged as a series of severe power outages.

It is possible and cost effective to condition monitor and maintain the ageing asset base, extending the average asset life and replacing only that which is no longer viable. However, the rising operating costs associated with this strategy must be taken to account when calculating trend expenditures. Empirical analysis suggests the ratio of annual operating expenditure to the asset base, measured at replacement cost, is not static. It rises from zero for new assets to around two per cent at age 25 years, before escalating to more than 12 per cent by age 50. Revealed costs, which rely on past expenditure, do not take account for the natural rise in maintenance expenditures associated with ageing assets. Over time, this will challenge the ability of the DNSPs to maintain network security.

In one recent regulatory determination[10] real operating costs per connection fell three per cent between the 'base cost' data and the first year of the next regulatory period; measured per MW of peak demand, unit costs fell as much as seven percent. There was no explanation as to why the 'efficient' revealed costs were reduced going forward. It may be argued the declines represent ongoing efficiency gains but a drop in operating unit costs of up to seven per cent in just two years at a time of ageing assets must be considered quite a stretch for the DNSPs.

2.2.2 Efficient cost defined: Benchmark Economics network cost model

The network cost structure model used in this report defines efficient cost as the line-of-best fit derived from a suite of linear regression models depicting the statistical relationship between unit costs and major cost drivers. As the small number of Australian electricity distribution service providers precludes development of a robust multiple regression model, the model adopts a step-wise approach. First, efficient costs associated with each major cost driver are estimated using linear regression models. Next, efficiency estimates from the individual cost models are combined to provide an envelope of efficient cost for any given level of the major cost driver

[9] Investment estimates based on probability of failure of the existing asset base.
[10] Real operating expenditure measured as base cost plus scale and escalation factor per MW peak demand and per connection.

Section 6.5.6 (c)(2) of Chapter 6 stipulates that benchmarking comparators operate 'in the circumstances of the relevant DNSP'; that is, Aurora is to be compared with DNSPs sharing a similar operating environment. Incorporating major cost drivers directly into the estimation model ensures estimates detailed in this report provide credible cost comparisons between networks with similar circumstances as required by the NER. The 'efficient' cost for a specific DNSP can also be inferred from a sample of businesses where there are no identical networks. Accordingly, it is possible to compare credibly the cost ratios of, say, EnergyAustralia, with a connection density of 35, with Country Energy with a connection density of only four. It is not necessary to develop separate urban and rural network models.

This provides a considerable benefit given the limited number of DNSPs in Australia and the wide variance in their operating conditions. Cost comparisons are also external to a DNSP's own costs, satisfying the requirement of CPI-X incentive based regulation.

The NER also requires expenditure to be prudent. Prudent, defined as 'decisions that are careful, take account of the likely consequences, and manage so as to provide for the future'[11] is a critical concern in an essential service provided by long-lived assets. A course of action which in the short term is low cost ie 'efficient' may be neither efficient nor prudent over the longer term. The longer run adequacy or prudency of the allowed cost of production has received less attention than the short run efficiency in comparative cost assessments.

Accordingly, this report will also examine the possible influence of the asset age profile of Aurora's network on operating and capital expenditure. This will provide a view on likely future expenditure beyond the five year regulatory period.

[11] Compact Oxford English Dictionary, 2007: The origin of prudent is the Latin *'prudens'* derived from *'providens'* or 'foreseeing'. Effectively, to be prudent, expenditure must be able to deliver the service not only today but also into the future.

3 Benchmarking

3.1 Role of benchmarking in regulation

External cost comparisons, often referred to as benchmarking or yardstick competition, were introduced by economic regulators to promote greater efficiency. Assessing performance against external costs rather than the internal cost of the network business was held to provide a greater incentive to lower costs and drive innovation

Benchmarking is one of the ten factors set down in the NER to be considered by the AER in making its determination on the efficiency of forecast operating expenditures. While benchmarking is viewed by the AER as an analytical tool to assist in its decision-making, it does not consider it sufficiently robust for expenditure estimation purposes.

However, a review of the ten factors set down in Section 6.5.6 (e) suggests benchmarking has a significant role in assisting the AER since it is one of only two factors providing a transparent and objective metric against which costs can be compared. The remaining eight relate chiefly to the judgment of the regulator. Table 1 lists the factors, the parameters for their assessment, and the nature of the assessment.

Table 1: 10 Decision factors – NER Section 6.5.6 (e)

6.5.6 (e) (1)	Parameters	Assessment
Information included in or accompanying building block proposal	No metric or parameters –	Judgment
Submissions received in the course of consulting on building block proposal	No metric or parameters -	Judgment
Analysis undertaken by or for AER	No parameters or metric	Judgment
Benchmark operating expenditure incurred by efficient DNSP over regulatory control period	Metric provided – expenditure of efficient	Objective–
Actual and expected opex during preceding regulatory control period	Metric provided-past expenditure	Objective -
Relative prices of operating and capital inputs	No metric	Judgment
Substitution possibilities between operating and	No metric	Judgment
Whether total labour costs included are consistent with incentives provided by applicable service target	No metric	Judgment
Extent forecast expenditure is referable to arrangements not at arm's length	Acceptable percentage not nominated	Judgment
Extent DNSP has considered, and made provision for, efficient non-network alternative	Acceptable level for 'extent' not provided	Judgment

There is no problem inherent in this structure but the lack of an external metric for testing regulatory judgments on expenditure allowances has been criticised by consumers and their representatives. A robust benchmarking process would provide not only a more objective assessment of efficient cost to support the AER and its decision-making, it would also help to identify genuine areas of over or underspend.

3.2 What is benchmarking?

Though simple in concept, benchmarking has proved more complex in practice. There is general agreement that a benchmark is a standard by which something is measured or judged[12], and that benchmarking is the act of comparing indicators of a DNSP's performance against that standard.

There is less agreement on whether the benchmark may be a firm on the efficiency frontier, or the average performance of the industry. Since the objective of incentive-based regulation is to replicate the outcome in competitive markets, the average performance would be the logical choice. Faced with a standard price in competitive markets, firms with costs lower than the average earn a higher rate of return than those with higher costs. Since all firms aim to maximise profits, average efficiency will increase over time, bringing lower prices for consumers.

Differing operating environments also present a problem. Electricity distribution networks operate within widely varying operating conditions which have proved difficult to identify and to measure accurately. There is, as yet, no agreement on these key cost drivers.

Issues also arise from the choice of the technique for estimating efficient performance which typically includes stochastic frontier, corrected ordinary least squares, and data envelopment analysis (DEA). Evidence suggests these different methodologies can produce efficiency scores and rankings that vary significantly[13].

After two decades of economic regulation these matters are still without resolution. This report will argue this follows from inappropriate model specification rather than from the benchmarking process per se.

3.3 Benchmarking methodologies

Methodologies for assessing comparative efficiency of network businesses include:

- Partial indicators – used universally;
- Regression analysis – UK, US, Canada, Australia;

[12] Wordnetweb.princeton.edu/perl/webwn, 2010

[13] Frasi, Mehdi and Filippini, Massimo, 2005. "A benchmarking analysis of electricity distribution utilities in Switzerland", Center for Energy Policy and Economics, Department of Management, Technology and Economics, Swiss Federal Institute of Technology, Zurich, Switzerland

- Total factor productivity analysis: US and New Zealand;
- Production frontier – Netherlands, Nordic countries; and
- Engineering models – Chile, Spain.

Each technique has its advantages and disadvantage but most still fall short of integrating the technical factors affecting network operations into the analysis. Credible benchmarking requires rigorous performance evaluation techniques, high quality, publicly verifiable data, and, for electricity distributors, careful modelling of operating conditions since end-user location and demand patterns are beyond management control.

3.4 Benchmarking and operating conditions

The critical role of the operating environment in selecting the appropriate assessment technique was identified by Andrei Shleifer[14] in his seminal article on regulatory benchmarking and yardstick competition, published in 1985. By relating a network distributor's own price to the costs of firms within a single industry, he argued, the regulator can force firms serving different markets effectively to compete, hence "yardstick competition". This concept has underpinned much of the development in efficiency assessment for incentive-based regulation.

Shleifer, however, added an important caveat. The efficacy of using costs of comparable firms as indicators of efficiency potential, he argued, is best illustrated for "identical" firms. However, as he took care to point out:

> *"even though implementing yardstick competition requires only two identical firms, there may be firms with no identical twins".*

If the firms are not identical, simple yardstick comparisons would not be appropriate. For the Australian DNSPs, with widely varying operating conditions, this means efficiency comparisons based on partial indicators such as cost per connection, line length, or capacity will be flawed.

In those instances where there are characteristics that create differing type firms Shleifer stated:

> *"Sorting firms into identical or even similar groups to apply yardstick competition is a very inefficient use of information. Even though implementing yardstick competition requires only two identical firms, there may be firms with no identical twins. The regulator can avoid this problem if he observes the characteristics that make firms differ, and corrects for this heterogeneity. This correction amounts to a regress of costs on characteristics that determine diversity."*

Generally speaking, benchmarking network costs has embraced the concept of yardstick competition but it has stopped short of recognising the caveat imposed by Shleifer that the comparisons must be between "identical" firms.

[14] Shleifer, Andrei 1985. "A theory of yardstick competition", *Rand Journal of Economics* (1985) Vol.16, No.3, Autumn

Even if cost analyses do include 'cost drivers' to adjust for differences in the operating environment, more often than not, these are drawn from precedent based on economic rather than empirical analysis of technical factors. Because efficiency comparisons are used to determine regulated revenues, Turvey argues:

> *"the targeted estimates of cost savings must reflect realistic estimates of what efficiency gains are feasible...judgments of comparative efficiency...require a deep and practical understanding of the functioning of the organisation and of the technology involved"*[15].

Knowledge of the technology involved is not always as deep as it could be.

Connection density (connections/km) is the most often used 'operating condition' to adjust for environmental differences, yet analysis of the link between costs and density indicates that load (MW/km) or energy (MWh/km) density provide a stronger indication of relative asset requirements. Load and length of line required per end-user, as well as the capacity required per end-user, that is, conductor and transformer size.

Another variable widely used as an output is energy flow (consumption) measured as MWh/km. Again, as Turvey points out, "energy distributed, is not a network output, but a network throughput." If energy is not an output then it can have no role in the network cost of production. The use of energy flow as an output is a carry-over from early cost analyses, which focussed on vertically integrated utilities. With the factors of production related to generation as inputs, the use of energy as an output was appropriate. For stand-alone distributors this is no longer so.

3.5 Benchmarking across countries

To strengthen benchmarking comparisons Australian's DNSPs, on occasion, have been compared to those in other countries, including New Zealand, the UK, and the US. It is not widely appreciated however, that there are significant differences between the operating conditions in these countries.

In New Zealand, the networks are smaller scale than in Australia with the whole industry about the size of EnergyAustralia. In the UK, gas is the major energy source with electricity playing a smaller role than in Australia. In the UK median domestic electricity consumption is 3,300 kWh per household with a capacity of 1.5kVA, compared with an average domestic consumption for Australia of around 8,500 kWh and a capacity of 3.5-5.0 kVA, depending on air-conditioning penetration. In the US, investor owned utilities (the network businesses for which data are publicly available) service only higher density urban areas. Non-urban areas are serviced largely by non-profit making rural cooperatives. Moreover, average domestic consumption is around 25,000 kWh due to the extreme cold/heat.

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[15] Ibid., p.2.

Different operating conditions mean different cost ratios, often substantially different; without appropriate adjustment for the variations cross-country comparisons will be meaningless.

3.6 Testing benchmarking results

Benchmarked efficiency scores and their rankings exhibit sensitivity to the method used[16.] This can only cause confusion for stakeholders. However, credible benchmarking demands the results from various analytical models exhibit similar characteristics. Testing across various estimation models, including parametric and non-parametric, and using panel, cross-sectional, firm specific, and industry wide data, Farsi and Filippini found consistency elusive; declaring the problem does not have a clear conclusion[17]; implying that benchmarking could not be usefully adopted to compare performance.

In addressing this issue, Bauer et al[18] in a well regarded paper, published in 1998, proposed criteria for evaluating the robustness and reasonableness of benchmarking results. Among the criteria were the requirements that different businesses should rank in approximately the same order, different approaches should identify roughly the same 'efficient' and 'inefficient' businesses, and demonstrate reasonable stability in the rankings over time. Though useful as a guide for identifying credible benchmarking results, Bauer's proposal does not provide a methodology for achieving such consistency in benchmarking outcomes.

For this it is necessary to return to Neuberg and Turvey and their prescription for detailed analysis of the network production function to identify key cost drivers. A review of the variables used in the Farsi and Filippini benchmarking model suggests the inconsistent results were due to mis-specification of the input/output variables rather than the model or data employed. The model used a triple-input single–output production function; prices of capital, labour, and input power purchased from generators were the three inputs with delivered electricity in kWh as the single output. Several operating conditions were also included; load factor, customer numbers, and size of service territory.

The output specified, kWh, is a throughput not an output with no connection at all to two of the three inputs, capital, and labour. The choice of the price of input power from the generators as an input is assumed to be a situation unique to distribution businesses in Switzerland. Turning to the operating conditions, the number of connections is a measure of scale rather than an environmental condition. Service territory size is unrelated to network costs since a network

[16]Jamash, Tooraj, and Michael Pollitt "International Benchmarking and Regulation: An Application to European Electricity Distribution Utilities" *Energy Policy*, **31** (2003): 1609-1622.
[17] Farsi and Filippini, 2005: pp 13.
[18] Bauer, P., A. Berger, G. Ferrier, and D. Humphrey, "Consistency Conditions for Regulatory Analysis of Financial Institutions: A Comparison of Frontier Efficiency Methods", *Journal of Economics and Business*, (1998), 50:85-114.

business may only reticulate a portion of its service territory. It is the length of network line (an asset) per connection that determines relative costs; many areas of a service territory may have no assets installed at all. Consider the difference in the ratio of network to service territory between the CBD network of Citipower and the almost state-wide service territory of Ergon, which is reticulated only in parts.

A detailed discussion of network cost structures, operating conditions, and key cost drivers is provided in Chapter 7.

4 A note on regression analysis

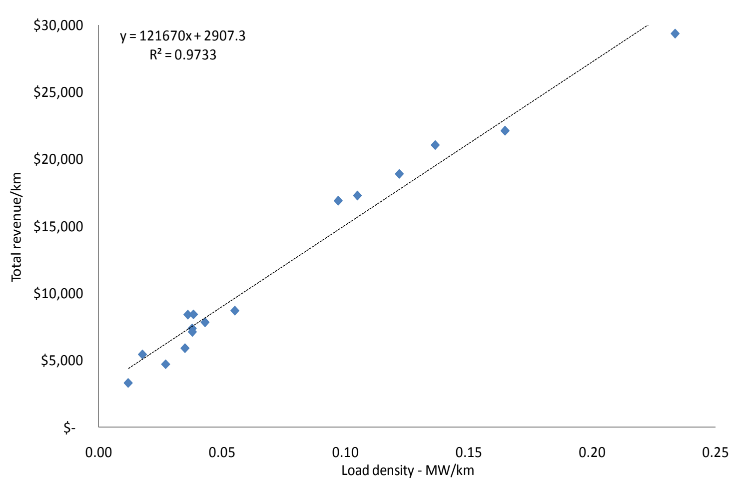
A digression on regression analysis may assist understanding of the methodology used in this study. This is intended only as an aid to understanding not as a dissertation on regression analysis; only features of concern are discussed and simplified for a range of readers. This section is drawn from the standard text by Sandford Weisberg[19.]

Linear regression analysis has been used in a number of regulatory performance analyses, in Australia and overseas, to study the relationship between network costs and possible cost drivers. But on occasion some regression models have misinterpreted the parameters of the technique and the results.

4.1 Regression models and explanatory power

Regression is used to study relationships between measurable variables. For simplicity, assume two variables Y and X, and we wish to estimate the change in Y, the dependent or response variable, associated with a change in X, the predictor or independent variable. For analysis of network costs the dependent variable could be total costs per km, and the predictor variable could be load density (MW/km). A useful way to begin a regression analysis is by drawing a scatter plot of the two variables - see Figure 3.

Figure 3. **Two variable regression scatter plot**



Typically the predictor variable is on the X or horizontal axis and the response or dependent variable on the Y or vertical axis. A straight line relating the two variables, X and Y, will be described by the equation:

$$Y = \beta_o + \beta_1 X$$

[19] Weisberg, Sanford 1985 – Applied Linear Regression Section Edition, John Wiley & Sons USA

where Y is the dependent variable, β_o is the intercept, (value of Y when X equals zero) and β_1.is the slope or rate of change in Y for a unit change in X.

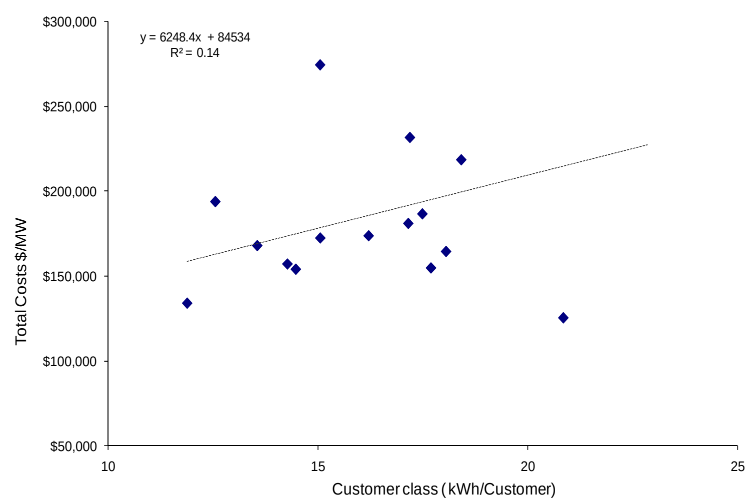
Figure 3 plots the X and Y variables, and provides the equation:

$$Y = 121670\,X + 2907.3$$

From this we estimate that total cost per km will increase by $1,217 for each 0.01 of capacity provided per km, plus the base cost or intercept of $2907.3; or around $15,683 in total costs per km for a network installation of 0.105 MW per km. The strength of this relationship is measured by R^2, the coefficient of determination. This measures the proportion of variability in a data set that is accounted for by the statistical model. The model's R^2 97 per indicates that nearly all of the variability in total costs per km can be explained by changes in load density.

The regression line which represents the line of best-fit for the values observed defines the line of least cost for any combination of the two variables – cost and cost driver. The slope of the regression line represents the rate of change in efficient cost per km as capacity provided per km rises. It is in this manner that it is used in this report to define cost efficiency. The usefulness of linear regression models for assessing efficient costs for regulatory purposes depends on the strength of the relationship. Not all variables exhibit the strength of costs and density. For example, Figure 4 plots the relation between costs per MW and customer class; the R^2 of 14 per cent for this regression line offers little explanation of the variability in costs.

Figure 4.**Costs per MW and Customer type (kWh/connection)**



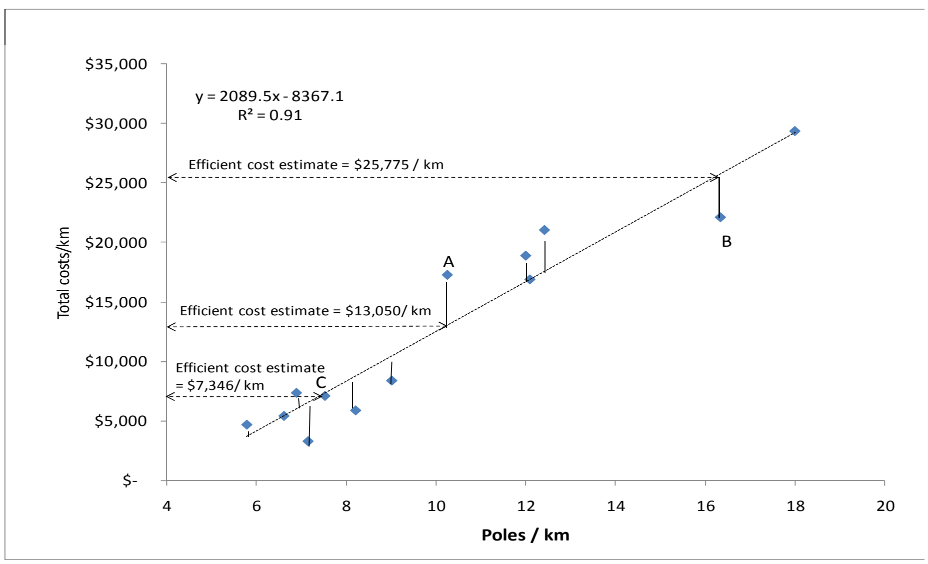
Viewed the other way, the model leaves 86 per cent of the variability in costs per MW unexplained.

4.2 Measuring efficiency relative to regression line

Having established a strong regression model with reasonable explanatory power, the next step is to interpret the results. Which network may be exhibiting costs above the trend line and which below? Essentially, there is the quick way, reading straight off the regression line, or the long way, estimating the efficient level of cost associated with the predictor variable, in this instance poles per km, by reference to the regression equation.

Reading straight off the regression line, relative efficiency is measured by the vertical distance between data points for the DNSPs and the trend line – depicted in Figure 5 by the vertical lines. For any given number of poles per km, the efficient cost level is read by reference to the vertical or Y-axis. In Figure X, network A has a cost level above the efficient trend line, B is below, and network C is sits on trend.

Figure 5.**Interpreting the regression line**



It would be incorrect to assume the lowest point of the trend line represents efficiency and the highest point inefficiency. Adjustment for the operating environment, in this case poles/km, is reflected in the slope of the line, not its range from lowest cost $5,000, to the highest, $30,000. Indeed, in Figure 5, the DNSP at the upper end of the regression line could be considered more efficient than the network at the lower end which sits above the trend line. The line's slope indicates only that cost per km will rise as the number of poles installed per km rises, as would be expected.

Using the regression equation to provide a more specific estimate of efficient cost, the level for Network A would be $13,050 per km, compared to the actual level of $17,262, for Network B it would be $25,775 per km, compared to the actual level of $22,900, and for Network C the estimate is almost identical to its actual expenditure.

The regression in Figure 5 provides useful information on possible reasons for the wide range in observed costs. However, for regulatory purposes the use of a single predictor variable is not sufficiently robust. There may be other factors contributing to the relative positions of the DNSPs. To strengthen the efficiency estimates it is necessary, in the absence of a sample sufficient for multiple regression analysis, to develop a suite of models to provide an envelope of efficient expenditure for the individual DNSPs.

5 Data

Data quality is a core condition for credible cost comparisons. It is standard practice that comparative analysis of productive enterprises is based on data that:

- measures a uniform product or service delivered:
- relates to a uniform measure of expenditure; and
- covers consistent time periods.

5.1 Data must measure a uniform product or service:

Comparisons against businesses "in the same circumstances", as stipulated by the NER, require a uniform or common product or service for the assessment. Such commonality would be breached if a step-change in network obligations was applied only to a sub-set of DNSPs. For example, additional expenditures in NSW were allowed as a pass-through for mandated higher reliability levels, while in Queensland additional regulated expenditure was allowed to redress past underspend.

The mandated changes were not insignificant; DNSPs in NSW received capex increases ranging from 25 to 50 per cent of regulated expenditure; comparisons against expenditures for these networks would be misleading if these step-changes were included. However, the introduction of mandated reliability improvements has not been uniform across the Australian jurisdictions. Structural adjustments to expenditure made on recommendations of governments and allowed as pass-through expenditures or regulated expenditures are not part of the normal building block revenue setting process and should not be used in comparisons of building block expenditures.

To ensure comparability between the DNSPs, the cost analysis in this report for the year 2009 will exclude these additional expenditures for NSW and Qld. The analysis for the period 2013-2015 will make no distinction since the mandated additional expenditures were relevant only until the end of the 2009-10 regulatory pricing period.

5.2 Data must measure uniform expenditures

5.2.1 Capital contributions

Lack of uniformity in the treatment of capital contributions also poses problems for regulatory cost comparisons. The jurisdictions vary significantly in their treatment of contributions. To provide like-with-like assessments of capital expenditure efficiency, gross expenditure data, which includes capital contributions, should be used, not the net data which excludes these expenditures.

Moreover, as the denominator in any cost ratio used for efficiency analysis, for example, line length, or MW capacity, will include the assets funded by capital contributions, the cost those assets must be included in the numerator.

Differences in the treatment of capital contributions are:

- In NSW capital contributions formed part of gross capex (capital expenditure) and were listed as a line item in IPART decisions, but were not included in regulated capex, which is treated as net. The AER discusses IPART's 2002 framework for capital contributions but makes no reference to them as an expenditure item; capex therefore must be net of capital contributions which are not included in the RAB.
- In Qld capital contributions are included in capex and rolled-forward into the RAB but are deducted from the AARR;
- In Victoria, the ESCV followed the process implemented by the Victoria Tariff Order. This required the roll-forward of the asset base to include gross capex (including capital contributions) but to exclude capital contributions. The AER adhered to this process; therefore gross capex includes capital contributions but regulatory capex is net of contributions which are not included in the RAB.
- In SA ESCOSA excluded customer contributions from regulated capex and also from the RAB but they were included in ETSA's 'gross' capital expenditure. In Table 7.1 of its Final Decision, the AER included a table from its draft conclusion on ETSA's capex allowance, listing customer contributions to gross capex – but in Table 6 of the Final report there is no reference to customer contributions. Capex therefore must be net of capital contributions which are not included in the RAB. These are substantial and amounted to $87.4m – or 30 per cent of total regulated capex in 2010.
- In Tasmania, capital contributions are included as a line item in gross capex but deducted to arrive at net capex. Capital contributions are excluded from the roll-forward of the asset base. Capital contributions amount to around 8 per cent of regulatory capex (i.e. net capex) in 2009.
- In Western Australia, capital contributions were added to the asset base as part of capital expenditure, but deducted from annual revenues. In the 2009 Decision, this was arrangement was changed. Capital contributions are now not rolled into the asset base but as an offset they are not deducted from revenue. This means that historic RAB for Western Power will include past capital contributions, but not the growth in the asset base going forward from 2009. Capital contributions amount to around 30 per cent of the asset base.

Table 2: Treatment of capital contributions

	Capital contribution	Included in regulatory capex	Rolled into RAB	% of net regulatory capex	Deducted from revenue
NSW	Yes	No	No	4% - 8%	No
Vic	Yes	No	No	5% - 19%	No
Qld	Yes	Yes	Yes	6%	Yes
SA	Yes	No	No	29%	No
Tas	Yes	No	No	8%	No
WA	Yes	No	Yes until 2008	51%	Yes until 2008

The analysis in this report will be based on gross capital expenditure to provide a uniform measure of capital expenditure.

5.3 Data must cover a consistent time period

The choice of a time period for the analysis is not straightforward. The AER has responsibility for economic regulation of five of the six jurisdictions, with the WA regulated by the jurisdictional regulator. Regulatory time periods are for five years but not all DNSPs share the same five year period – see Table 3.

Table 3: Regulatory five-year pricing periods

	2005 - 2009												
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
SA		ESCOSA determination					AER determination						
NSW	IPART determination					AER determination							
VIC		ESC determination					AER determination						
QLD		ESCOSA determination					AER determination						
TAS				Otter determination					AER determination				
WA			ERA determination			ERA determination							

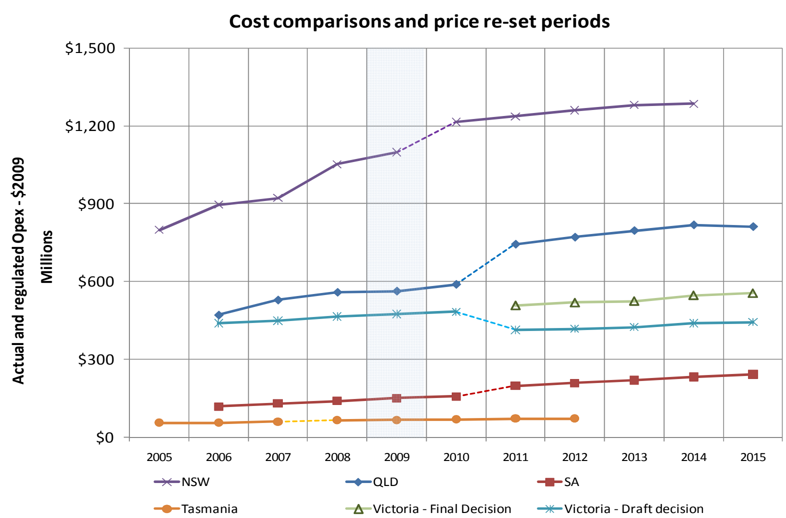
Examining past expenditure patterns shows that different features of the operating environment can dominate the decision-making process at the time of a regulatory determination. In 2000, the focus was on reducing expenditure to increase efficiency, in 2005 there was growing awareness of the deterioration in network service standards, and by 2009 the impact of the ageing asset base on investment was emerging.

From Table 3 it is evident that 2009 is the most recent year when all DNSPs were within approximately the same decision-making environment. Sharp changes occurred in expenditure allowances in the following five-year period.

For this reason, 2009 has been selected to assess the relative efficiency of Aurora's 'current' expenditures.

Five year average data, based on the five year regulatory period, is a typical choice, based on perceptions of volatility in data for an individual year. However, this approach is not without its shortcomings. While intra-period data can be relatively consistent, sharp increases can occur between price periods.

Figure 6.**Regulatory expenditures: Step-changes between pricing periods**



The step-changes in average expenditure between pricing periods depicted in Figure 6 range from 13 per cent up to 49 per cent. Changes of this magnitude will affect the usefulness of the five year average depending on the period selected and the DNSP under review. Using the years 2005-09, as an example, the average data would include two price periods for all jurisdictions except NSW. SA, Victoria, and Qld have one year (or 20 per cent of the five year average data) set in an earlier period. WA has two years, and Tasmania has three years.

For Aurora, this aspect is particularly pertinent since an average for the years 2005-09[20] would include data from three years of the period preceding the current pricing period. This could have the effect of increasing the step-change between its retrospective average expenditure and the proposed expenditure for the 2012-2017 regulatory period. Given the focus on the change in expenditures between two price periods it is best to minimise the bias.

[20] 2005-09 would be the latest five year period available, since data for 2010 were not available at the time of writing this Report.

5.4 Data used in this study

5.4.1 Whole-of-state networks

There are 12 Australian DNSPs; nine connecting specific service territories (eg Citipower and the Melbourne CBD, Energex and Brisbane and urban environs, and Aurora with urban, rural and remote rural); and three single state-wide networks (ETSA, Aurora, and Western Power) providing a service across all densities and customer classes. To strengthen the sample and provide more appropriate comparators for the single-state based networks, three additional state-wide 'networks' have been constructed by aggregating (not averaging) the financial and network variables for the individual networks in Victoria, NSW, and Queensland.

The cost ratios and operating condition variables were then derived from the aggregated data for each jurisdiction. The results for NSW, QLD, and Victoria provide a close match to the whole-of-state networks - see Table 4, providing Aurora, ETSA, and WP with credible benchmarking peers.

Table 4:Operating conditions - whole-of-state networks

	Load density	Connection density	Load factor
Tasmania	0.036	10.7	49%
NSW	0.043	11.8	53%
Vic	0.055	16.3	48%
Old	0.038	9.6	53%
SA	0.035	9.1	40%
WA	0.038	10.7	56%

Averaging these operating condition ratios, rather than aggregating the actual data, provides connection density ranging from 14 connections per km for Qld, to 20 for NSW, and up to 33 for Victoria. These densities do not offer suitable comparators for the whole-of-state networks. Moreover, average cost ratios have been tested against operating conditions and the results indicate little if any relationship with the major cost drivers.

5.4.2 RAB and expenditure

The use of the RAB to normalise expenditure as a guide to cost efficiency is not uncommon. However, as Shleifer observed, single indicators can only provide credible comparisons if the businesses are identical. This is not the case with the RAB for the DNSPs. Asset age, rates of depreciation, and asset condition result in often large differences in the RAB.

In Victoria, on privatisation, asset values were adjusted up for the urban networks and down for the rural networks to allow more uniform tariffs; rates of deprecation were also adjusted to allow a faster return of capital. In Queensland rapid load growth increased the RAB by 100 per cent between 2000-

2010, compared to 12 per cent growth in Victoria, 68 per cent growth in NSW, 47 per cent in Tasmania, and a decline of 5 per cent in South Australia. Clearly, the ratio of capital expenditure to the RAB will reflect these changes. Likewise, the ratio of operating expenditure to RAB will reflect the ratio of old to new assets.

Accordingly, the ratio of expenditure to the RAB is not considered suitable for efficiency comparisons and will not be referred to in this report.

5.4.3 Data for this report

This report will use data from two periods. To assess Aurora's performance in its current price period the year 2009 has been selected in preference to the 2005-09 average. Cost comparisons in 2011 based on data flowing from decisions made in 2005 appear less than robust at a time when there have been substantial increases in expenditures. To assess Aurora's proposed expenditures for the 2012-17 price period, a three year average of the data for the years 2013-15 has been selected. 2013 is the first year of the new price period for Aurora while 2015 is the last year for which data are available for the other DNSPs.

The data are actual expenditures, taken from regulatory determinations. Where real data has been used, data are first calculated in nominal dollars and converted to 2010 dollars by reference to the ABS CPI – This produces a consistent data set.

Every care has been taken to ensure the data are a true and faithful account of those data published by the regulators and other authorities. There will be minor variations since myriad adjustments to regulatory data can introduce complexity, and indeed, confusion. For example, smoothing, however desirable, can shift revenue from year to year.

6 Distribution network cost structures

6.1 What do distributors do?

Electricity distribution businesses provide a physical network for distributing energy flows. The distribution network is only one link in the electricity supply chain, intermediate between generation, transmission, and retail supply. Low voltage distribution networks connect the high voltage bulk supply points on the transmission grid directly to end-users located at varying points within the distribution service territory.

The network product consists of a bundle of services rather than the more typical single discrete output, for example, a loaf of bread or a can of beans. Chapter 6 of the NER recognises this aspect of network systems referring at all times to the regulation of distribution services. Network services include connecting end-users to the high voltage transmission network, providing system capacity to meet their peak demand, and transformation of the voltage of the energy delivered at the generator bus-bars to levels suitable to operate end-user equipment. As an essential facility, electricity network businesses are also expected to operate networks to assure reliable deliveries and to provide prompt restoration of interrupted supply.

It is also important to recognise that in contrast to competitive businesses, the level of output for networks and the conditions within which they operate are generally outside the control of management. That is, scale and operating conditions are largely exogenous variables; management cannot limit the number of its connections, or supply less capacity than demanded, or refuse to connect remote end-users. These may be profit maximising options but they are not plausible strategies for an essential facility.

6.2 Defining network inputs and outputs

Economics offers useful guidance for analysing network costs. In particular cost of production theory provides a conceptual framework for identifying inputs and outputs, a necessary condition for measuring cost efficiency.

Cost of production theory, based on the firm's technological production function, describes the way in which firms transform purchased inputs (the factors of production) into outputs of goods and services. A range of factors including output scale, certain operating conditions, and managerial efficiency will influence the ratio of outputs to a given level of inputs.

In terms of the physical production process, network inputs include conductors, poles, transformers, substations, and operating systems. Measured as financial flows, inputs are the building blocks used to estimate regulated revenues: the rate of return on, and of, capital and operating expenditure. Network outputs are the transformed resources and include network connection to the end-user, capacity to meet peak demand, and reliability of the system. Recall, energy flows are not an output -- they are a throughput. A more detailed discussion on energy flows and cost analysis is provided in the next section.

6.3 Network outputs and energy flow (MWh)

This section discusses in more detail the erroneous use of energy flow as a network output. Turvey, in reviewing the cost model developed by OFGEM[21], noted that the use of a weighted sum of network length, connections, and MWh as a measure of scale may be simple, but any correlation between costs and energy flows does not prove causality. Why? because:

> *"A distribution network acts passively in distributing energy along its lines and cables and through its switchgear and transformers; the amount distributed is not decided by the distribution network operator. In the short-run a load alteration will not affect the size of the network and will have only trivially minimal effects upon operating and maintenance costs."*

If energy flow has little, if any, affect on cost its use an output is not only inappropriate; it will provide misleading cost comparisons among those DNSPs with different load factors. The indicator, cost/MWh, simply measures the price charged for the use of the system, an interpretation confirmed by the term "distribution use of system charge.

Network capacity investment is driven by demand for peak capacity which, in turn, is determined by the type of end-users and their consumption profile. Peak demand capacity is measured in MW, with each MW capable of providing 8760 hours of energy flow per annum. However, actual energy flow, measured in hours, is determined by average energy demand; the ratio of average demand to the peak is termed the load factor.

Considerable differences may exist between peak and average capacity. Load factors among the Australian distribution networks vary from a low of 49 per cent to a high of around 61 per cent. In Australia load factor is largely the result of natural endowments such as mineral resources (Queensland), and/or the presence of a large manufacturing sector (Victoria), or even the penetration of gas (Victoria and South Australia). While demand management policies may bring small adjustments to load factor, the difference between the high and low load factor networks in Australia is beyond the control of network management.

The use of $/MWh as a cost indicator places networks with low load factors at a disadvantage because it does not measure cost. In regulated pricing, the cost of a network is defined as the sum of the building blocks, or annual revenue. That is, the rate of return on, and of, capital plus operating and maintenance expenditure. In turn, these "blocks" are determined by the level of investment in the network necessary to accommodate the demands of end-users. Once the investment is made, its cost is recouped, over time, by charging a fee for

[21] Ibid, p15

network use. For any given cost, increasing the energy flow through the network will lower the unit price, that is cost/energy flow or $/MWh.

Consequently, while networks may well have comparable costs ($/MW), those with higher energy flows relative to network capacity provided (defined as load factor), will exhibit lower prices, $/MWh, since they are able to spread their high fixed costs across a greater number of units "sold". The simple arithmetic underlying the impact of load factor on comparative 'prices' is presented in Table 5 drawing on data from Australian DNSPs:

Table 5: Load factor and network prices

	Load factor	Energy/MW MWh	Total cost/ peak MW	Price per MWh	
Network A	61%	5343	$193,875	$193,875/5343 =	$36.2
Network B	49%	4292	$188,386	$188,386/4292 =	$43.8

Network A, with a 61 per cent load factor conveys 5343 energy hours per MW of capacity out of a possible 8760 hours, compared to Network B, with a 49 per cent load factor which conveys only 4292 hours. Network A, with an energy flow per MW 25 per cent greater than Network B, is able to charge an average price 17 per cent below that of Network B, even though it has marginally higher costs. Figures 7 and 8 illustrate this point.

Figure 7. **Cost: Total revenue per MW capacity and connection density**

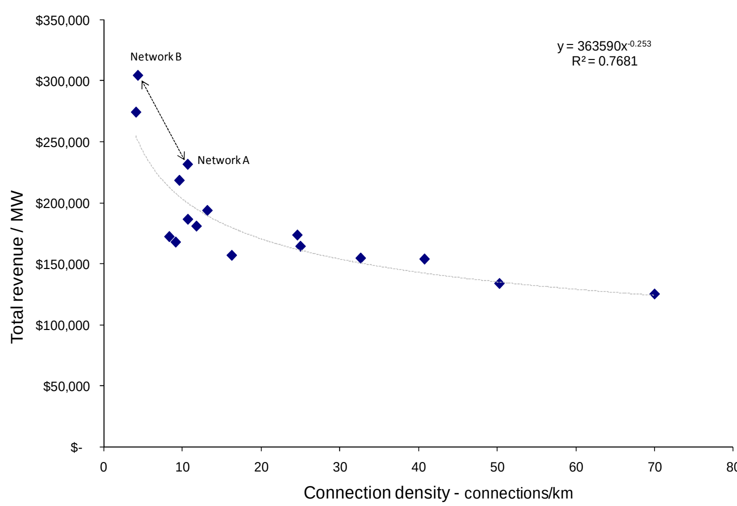
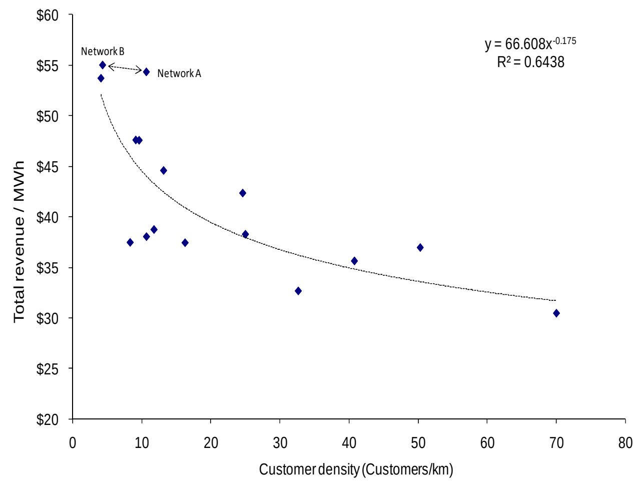


Figure 7 plots average cost, measured as total revenue/MW, against connection density, (connections/km) while Figure 8 plots average price, measured as total revenue/kWh, also against connection density. There are a number of DNSPs which change their relative position quite significantly depending on denominator selected. In Figure 7 we observe that network A's cost ratio at

$230,000 per MW is well below the $304,000 per MW of network B; network A would be judged more efficient than Network B.

However, selecting energy flows – MWh – as the denominator in the cost ratio produces a different result – see Figure 8. Network A now has a "cost: ratio almost as high as Network B; its relative efficiency advantage has been almost eliminated.

Figure 8.**Price: Total revenue per MWh energy flow and connection density**



The cost, or total revenue, for each network has not changed between the two ratios; the apparent change in relative efficiency of the networks simply reflects the choice of a denominator (energy flow) that is not relevant to the costs and quantities of network inputs.

6.4 The physics of electricity flows and impact on assets

Links between costs and operating conditions detailed in this report recognise the influence of the physics of energy flows on network assets, and hence, cost. For end-users to operate their equipment and appliances efficiently and without damage, electricity must be distributed within certain physical parameters such as voltage, reactive power, harmonics, and stability. Network design seeks a three-way trade-off between these technical constraints, the location and consumption pattern of end-users, and their willingness to pay.

The link between the energy flow physics and network assets outlined in the following discussion is presented only as a guide; it should not be read as an expert review of the physics of energy flows.

Two fundamental principles which closely influence the design of electricity networks are the:

1. Economic choice of conductor size: Kelvin's law; and
2. Economic choice of distribution voltage: Ohm's law.

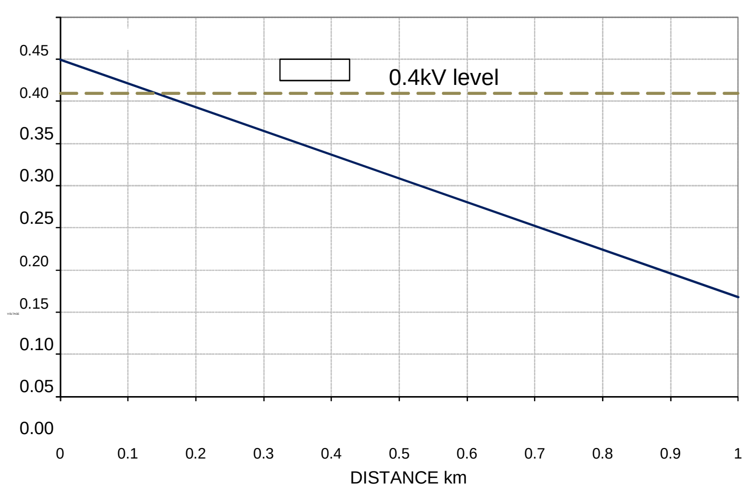
Kelvin's Law, derived from the second law of thermodynamics and waste heat/entropy, governs the size of the conductor required to optimise its life-time cost. The capital cost of the conductor and the cost of energy losses are governed by the size of the conductor. A bigger size conductor would be more costly, but due to its lesser resistance the cost of energy losses will be smaller. Conversely, a smaller size conductor will be cheaper, but its greater resistance will increase the cost of energy loss. Effectively, the optimum size is one where the annual capital cost of conductor is equivalent to the cost of the losses for that line.

Ohm's Law, derived from impedance and voltage drop, governs the line voltage necessary to deliver energy at the required voltage. As one popular text book explains[22]:

> *"In alternating current circuits, opposition to current flow occurs due to the interaction between electric and magnetic fields and the current within the conductor; this opposition is called "impedance". The impedance in an alternating current circuit depends on the spacing and dimensions of the conductors, the frequency of the current, and the magnetic permeability of the conductor and its surroundings."*

As voltage drop is a function of distance, the longer the line between the distribution sub-station and the end-user, the greater the voltage drop. To deliver required voltage, say, to a domestic consumer, longer distances require additional assets. Network engineers face a range of technical options including higher voltage conductors, fatter conductors, or taller poles to allow higher heating ratings for the conductors. Cost also affects the equipment choice with consumer willingness to pay limiting the cost of the solution. To illustrate, Figure 9 plots the distance over which a LV conductor can deliver the required voltage to a domestic consumer.

Figure 9.**Line length and voltage drop – domestic consumer**

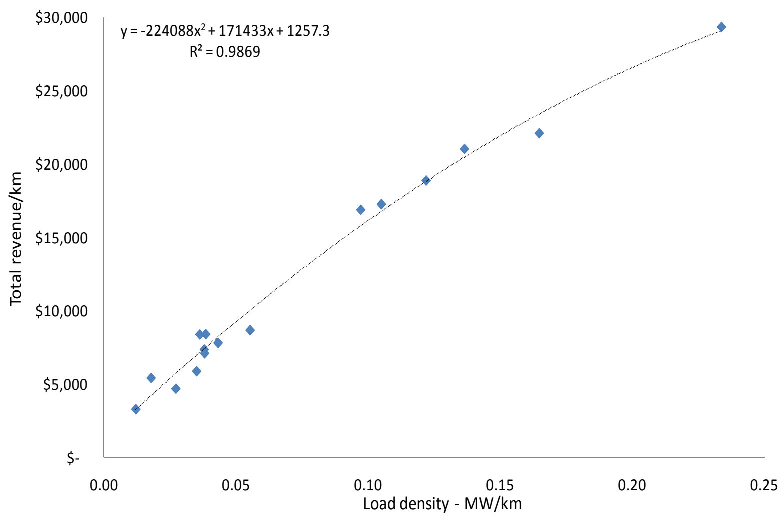


[22]Jennesson, Jim. *Electrical Principles for the Electrical Trades*, 5th edition, McGraw Hill, 2002.

With an average peak demand of 0.3 kVA per domestic consumer, a typical LV line (O.4kV) would be adequate up to a distance of 150 metres in either direction from the transformer. In Figure 9 this is where the 0.4kV line intersects required voltage line. If there is air-conditioning load, peak demand may rise to 0.5 kVA or above, and the voltage would only be maintained for a distance of 80 metres, in either direction.

The universality of these laws forges a strong link between costs and operating conditions over a wide range of densities and customer type. Figure 10, plotting total revenue per km against load density illustrates clearly the strength of the relation.

Figure 10.**Load density and total costs/revenue per km**



It is unnecessary to distinguish or separate urban or rural networks or large and small scale networks to compare cost efficiency since the same set of principles determines asset requirements across all electricity distribution networks.

6.5 Density and relative costs

Reflecting the impact of these two laws, density, whether measured as load, energy, or connection, is the major cost driver for electricity distribution networks. This influence is manifest in the:

- equipment type: line voltage, pole size and spacing, transformer size and number and hence relative costs; and
- asset ratios: ratio of lines (poles and conductors) to capacity (transformers) and hence relative costs.

6.5.1 Equipment type

The affect of density extends across almost the entire range of equipment: conductor type, voltage level, pole type, transformer and sub-station size and number; as assets vary so too do costs.

Using transformer requirements as an example, urban networks typically consist of LV lines (0.4kV), with transformation from 11kV at multiple-user transformers. In contrast, rural networks consist largely of HV conductors; 22kV is most common, with transformation to the low voltage required by end-users on a dedicated transformer basis. While a 500MVA transformer may supply 100 domestic consumers in an urban network, a single 16kVA transformer can be required for each rural connection. Measured across the Australian DNSPs the difference in transformer cost per connection can be significant (Table 6).

Table 6: Transformer unit cost – Urban and rural

Network density	Connections/ Transformer	Transformer size	Transformer cost	Cost/ connection
Urban	100	500kVA	$22,000	$220
Rural	1	16kVA	$2,650	$2,650

In turn, the number and size of transformers will also influence relative levels of operating expenditure. It is more labour intensive to inspect and maintain the large number of small, widespread transformers in rural areas than the fewer, larger transformers situated in urban networks.

In addition to density, the type of end-user will also influence asset requirements. While a typical domestic consumer will be supplied at LV from a shared pole mounted transformer, a large industrial consumer may require supply at 11kV or even 22kV, supplied directly from a zone-substation by multiple feeders, to provide the required high levels of supply reliability. Again, the cost differences can be significant.

Useful input to the debate on the influence of density and load profiles on asset requirements was provided in the NER Version 17 Chapter 6, Schedule 6.3. Defining connection cost categories on the basis of assets necessary for different types of connections, Schedule 6.3 explicitly linked operating conditions to network assets. In support it presented a range of diagrams to illustrate the growing complexity of asset requirements, and hence costs, as location and average consumption varied. These are presented in Figures 11 a, b, c, and d.

Figure 11.**a: Assets:Domestic connection-Urban -Connection density 30/km**

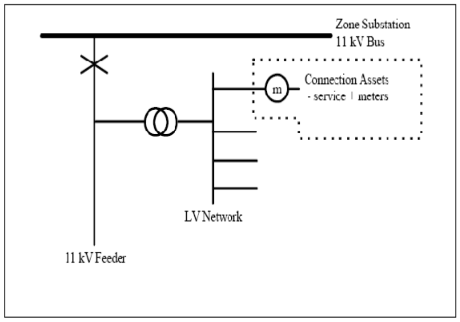
	Zone substation 11kV bus 11kV feeder LV network Transformer Connection assets -

Figure 11b: Assets: Domestic connection - Rural - Connection density 5/km

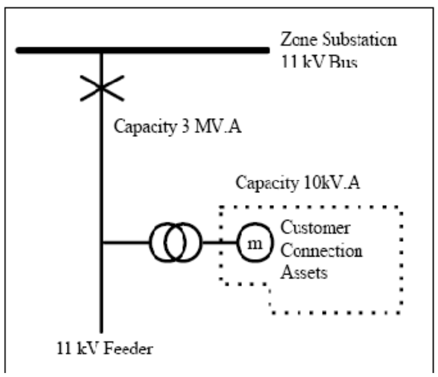
	Zone substation 11kV bus – 11kV feeder LV network Dedicated transformer Connection assets

Figure11c: Assets: 3MW industrial connection

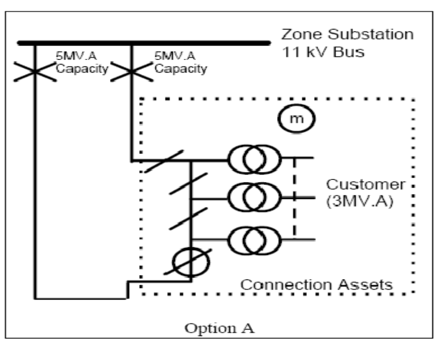
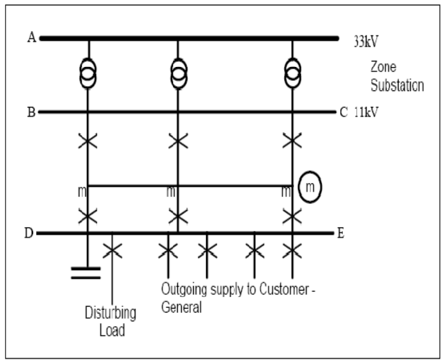
	Zone substation 11kV bus 11kV feeder LV network Two transformers Connection assets

Figure11d: Asset requirement: Large industrial connection 10+MW



Zone substation 11kV bus

11kV feeder

LV network

Two transformers

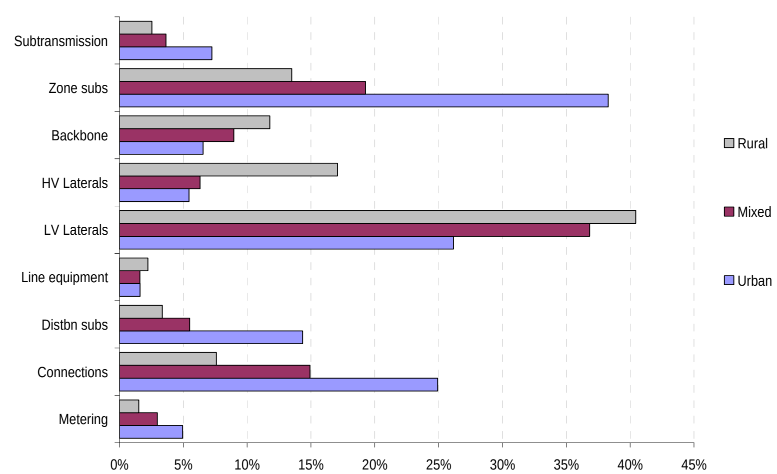
Connection assets

Simply put, the level of efficient cost will follow the asset requirement for each level of density and customer type. It follows any comparison of cost performance for regulatory purposes must include adjustment for differences in operating conditions between the DNSPs. The significance of these linkages in performance analyses stands independently of the subsequent revisions to Chapter 6 and the omission of the above diagrams.

6.5.2 Asset ratios

The ratio of line assets (conductors and poles) to capacity assets (substations and transformers) is also a function of connection density. A network planning model[23] has been used to calculate the different asset proportions per connection, across a range of assets (Figure 12).

Figure 12. **Asset requirements and network density**



[23] Elder, L.A. and Beardow, M.I. *"Eldow, A generic engineering-economic model for analysing electricity distribution networks"*, EEI Conference, 2001

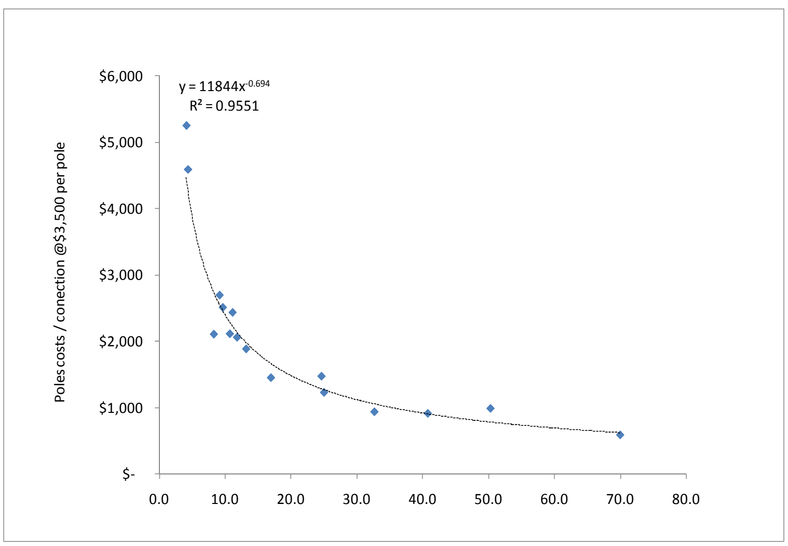
Three types of networks are compared; urban; mixed (urban and rural), and rural. Typically, urban networks may have 50 per cent of their assets in lines compared to around 67 per cent for rural networks. On the other hand, investment in substations and transformers is around 34 per cent for urban networks but only 26 per cent in rural networks.

Urban networks tend toward a lower line to capacity ratio than rural density networks, since the distances are shorter. Conversely, urban networks have a higher ratio for capacity assets because the load density is higher. On average, 14 metres of line and 0.17 of a pole are required to connect an end-user in the CBD, 30 metres of line and 0.40 of a pole in an urban area, and 245 metres of line and 1.75 poles to provide a rural connection. It follows that costs for an urban connection will be lower than for a rural connection.

These differences may affect not only replacement schedules since, on average, lines have longer asset lives (52 years) than capacity assets (42 years), but also expenditure ratios. The asset base has a measurable influence on relative operating expenditure; poles must be monitored and treated, conductors inspected, and trees trimmed. With a greater proportion of poles and wires to transformers, lower density networks, on average, have a higher rate of operating expenditure for any given network density.

Figure 13 plotting estimated pole cost per connection against a range of Australian connection densities reveals the strength of this relation.

Figure 13.**Pole costs per connection and connection density**



Pole costs per connection decline from around $5,250 per connection for a rural network with five connections per km down to $750 per connection for a CBD network with 70 connections per km. Mimicking many of the cost per connection curves used in performance analysis Figure 13 provides robust evidence of the link between assets and density. Whether an urban network at the lower end of the cost curve is also efficient can only be determined after the impact of density has been taken to account.

6.6 Network cost structure model

Accordingly, it is held that electricity distribution businesses transform capital and other inputs into the following outputs:

Connectivity - extent of the distribution network that connects bulk supply points to end-users; specified in the cost model as line length km -- it represents the contribution of poles and conductors;

Capacity – capability the network to satisfy the demand of end-users; specified in the cost model as coincident peak demand measured in MW -- it represents the contribution of transformers and substations;

Connections – number of connections to the network; specified in the cost model as the number of end-users connected -- it represents the contribution of connection equipment eg dedicated poles and meters, and end-user related services; and

Reliability – availability and continuity of energy delivery to end-users; specified in the cost model as SAIDI -- it represents the contribution of such inputs as equipment redundancy, multiple circuits, and operating and maintenance practices.

Two key business conditions influencing the link between inputs and outputs have been identified statistically from a wide range of environmental factors, they are:

Load or connection density: measured as peak capacity (MW) provided, or end-users per km line length; density reflects the productivity of capital per line length; and

Customer class: measured as the average level of energy consumption for end-users. A variation of consumption levels, load factor, is measured as the ratio of average to peak demand; customer class or load factor provides a measure of the productivity of the capacity of the system.

Table 7 details the specification for the cost structure model detailed in this report.

Table 7: Network cost structure model

Inputs	Measured by	Outputs	Measured by
Poles, conductors	Building block revenue, opex or capex	Connectivity	Line length km
Transformers, substations, etc	Building block revenue, opex or capex	Capacity	Peak demand MW
Poles, conductors, connection equipment	Building block revenue, opex or capex	Connections	Number of end-users
Redundancy, maintenance teams	Building block revenue, opex or capex	Reliability	SAIDI etc
Business conditions	**Measured by**		**Categories**
Load density	Peak demand/km		CBD, urban, rural
Connection density	Connections/km		CBD, urban, rural
Customer class Load factor	Average kWh/connection Average demand MW /Peak demand MW		Residential, commercial, industrial

7 Distribution network cost drivers

This section details the cost model developed from the network cost structures discussed in Chapter 4. It is in three sections. To begin, it tests for the presence or otherwise of economies of scale. Next, there is a detailed explanation of the major operating conditions and their link with network costs. The relation between the cost drivers and total costs is modelled in the final section. Analysis of network operating and capital expenditures will be examined Chapter 9

Total cost is defined as the smoothed regulated annual revenue allowance. This is considered to be an acceptable proxy for cost since the building block regime, is a cost based model. Costs related to the asset base, the rate of return on and of capital, typically comprise around 70 per cent of building block revenues, and operating expenditure, the remaining 30 per cent.

7.1 Network Scale

Scale of operation may influence the cost of production. There may be economies of scale in production; the opportunity to purchase more cost effective larger equipment units; or the possibility of lower average costs through bulk purchases of essential inputs. There is also the ability to share the relatively fixed corporate overheads across the larger business. The empirical literature suggests, however, that while some economies of scale are present in electricity distribution networks they are relatively limited.

Table 8 presents the scale parameters including number of connections, lined length, capacity, and energy flows for the Australian DNSPs. The scale of the DNSPs varies significantly. The largest network measured by energy flows, EnergyAustralia, exceeds the smallest, Aurora, by a factor of seven. The longest network, Country Energy, exceeds the shortest, CitiPower, by a factor of 38. Aurora, which is Australia's smallest state-wide DNSP, has the lowest maximum demand.

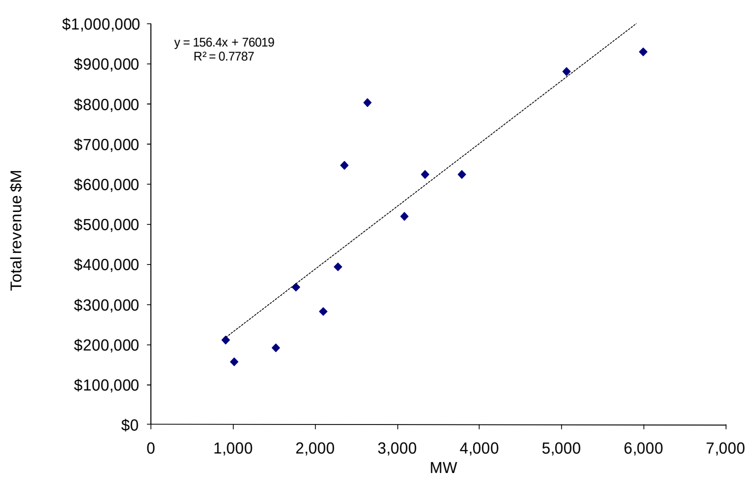
Detecting the presence or otherwise of scale effects is disadvantaged by the relatively small number of Australian DNSPs and the predominance of operating conditions as cost drivers. Networks with the largest number of connections tend to provide a network service to dense urban areas, while those with the longest line length tend to connect rural territories. The use of connections or line length to assess scale benefits will be unsuitable since their costs tend to reflect the type of network; urban networks have comparatively lower costs per connection while rural networks have comparatively lower costs per line length. Absent these cost drivers, the most suitable measure is network capacity, measured as peak demand MW.

Table 8: Australia DNSPs - network scale overview - 2009

Network	Energy GWh	Connections Nos	Line Length km	Peak Demand MW
Aurora	4,778	277,870	24,525	890
EnergyAustralia	28,422	1,606,005	44,836	5,484
Energex	20,780	1,281,704	49,684	4,792
Integral Energy	16,281	901,676	35,238	3,560
Western Power	12,967	936,435	86,005	3,101
Ergon	14,592	638,588	141,823	2,571
Country Energy	12,032	799,145	193,296	2,252
ETSA	10,898	803,849	82,850	2,563
PowerCor	10,480	695,970	82,077	2,000
United Energy	7,609	640,066	12,472	1,844
SP AusNet	7,670	610,697	44,000	1,555
CitiPower	6,255	300,000	4,236	1,416
Jemena	4,264	299,112	7,180	1,009
NSW	56,735	3,306,826	273,370	11,296
Victoria	36,367	2,545,845	152,091	7,824
Queensland	35,372	1,920,292	191,507	7,363

In a simple assessment of scale benefits, MW peak demand was regressed against total revenues - see Figure 14.

Figure 14. **Network Scale: Total revenues and network capacity (MW)**



As expected, revenues increase in line with the rising level of capacity installed. However, to determine whether there is a link between increasing scale and decreasing unit cost it is necessary to compare the change in cost associated with a change in scale. The equation in Figure 13 suggests the presence of some economies of scale. There is a base cost of around $76,000 rising by $156,400 for each additional MW installed. As capacity installed rises the base cost is averaged across the greater number of units, reducing the average cost. Based on the equation in Figure 13 the total revenue requirement per 1000 MW for the range of peak demand for the DNSPs was estimated. Next, the average revenue per MW was derived to provide capacity costs as scale increased. The data are presented in Table 9.

Table 9: Economies of scale – Total revenues per peak demand MW

Installed capacity MW	Estimated total revenues	Total revenue per MW
1000	$ 232.419M	$232.000
2000	$ 388.819M	$194.000
3000	$ 545.219M	$182.000
4000	$ 701.619M	$175.000
5000	$ 858.019M	$175.000
6000	$1,014,419M	$169,000

Overall, the larger DNSPs with a capacity above 4,000MW will derive some economies of scale relative to the smaller networks. There are however fewer gains above that level. Conversely, the smaller DNSPs, especially Aurora with only 1000MW of capacity, will be at some disadvantage due to their smaller scale.

7.2 Reliability

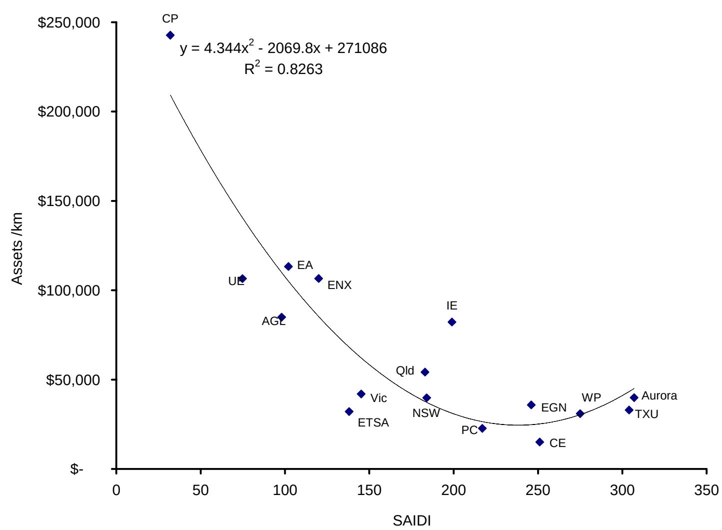
Reliability, defined in this analysis as the System Average Interruption Duration Index (SAIDI)[24], is a function of the level of network investment, maintenance, and age. In this respect it should be regarded as a network output. Investment in multiple circuits, equipment redundancy, and higher voltages lifts supply reliability. Likewise, availability of maintenance crews and the level of tree trimming expenditures ensure the equipment provided remains in good operating condition.

Reliability investment will reflect a trade-off between the quality of supply required by end users and the commercial viability of the associated expenditures. High reliability is generally associated with higher density networks where the greater number of connections per km provides the higher revenues necessary to fund the reliability investments (Figure 15).

[24] The use of SAIDI in this instance is not to suggest that it is an ideal measure of reliability; there are other more useful and appropriate indicators. However, for the purposes of this paper SAIDI has been selected since it is widely used and accepted as a measure of reliability.

SAIDI of 50 minutes provided by a CBD network is associated with assets of $240,000 per km, while at the other extreme a rural network may have a SAIDI of more than 250 minutes but its assets at $15,000 per km are less than 7 per cent of the assets required for the CBD network.

Figure 15. **Reliability (SAIDI) and assets per km**



It has not been common practice to include measures of reliability as an output in network cost models. Methodological issues associated with its inclusion in econometric cost models have been cited as one reason while reliabilities role as a network output has been rejected in a number of academic papers. Irrespective of the justification for its omission, the outcome has been misleading cost estimations.

Excluding reliability from cost models causes the explanatory power that it could offer to be allocated to the variables that are included in the model, often distorting cost comparisons. At the same time, omitting reliability has obscured the very real investment requirements necessary to deliver higher levels of reliability.

7.3 Operating conditions

Scale may present one possible cost benefit for distribution networks, economies of density present another. For any given length of network, providing greater peak capacity (load density), conveying more energy (energy density), or connecting more end-users (connection density) may offer significant cost benefits. Economies are can also be derived by distributing more energy per connection (customer type) or for any given level of capacity (load factor). Management has little control over these determinants, since connection location, load, and energy consumption are choices of the end-user, not the service provider.

Key operating conditions for the DNSPs: load/connection density and customer type are presented in Table 10.

The DNSPs with the highest load and connection density are the three urban systems in Melbourne, CitiPower, Jemena, and United Energy. DNSPs with the lowest densities are the largely rural networks of Ergon and Country Energy. Aurora has a density similar to the other state-wide networks of ETSA and WP, and the aggregated NSW, Victoria and Queensland networks, confirming the usefulness of these aggregated comparators in the benchmarking analysis

Table 10: Operating conditions – DNSPs

Network	Load density MW/km	Connection density Nos/km	Customer type kWh/connection	Load factor
Aurora	0.036	10.7	14.47	60.1%
EnergyAustralia	0.122	35.0	17.37	54.1%
Integral Energy	0.101	24.5	18.28	49.1
CitiPower	0.327	69.6	20.17	47.0%
United Energy	0.148	49.7	12.99	41.4%
Jemena	0.141	41.4	14.35	49.4%
Energex	0.096	24.5	17.50	46.9%
SP AusNet	0.035	13.3	12.65	49.7%
Western Power	0.036	10.5	17.15	56.0%
ETSA	0.031	9.5	14.45	40.3%
PowerCor	0.024	8.2	15.47	52.6%
Ergon	0.018	4.2	23.15	63.2%
Country Energy	0.012	4.0	15.47	58.3%
NSW	0.041	11.7	17.16	53.4%
Victoria	0.051	16.3	14.62	47.9%
Queensland	0.038	9.4	19.34	52.5%

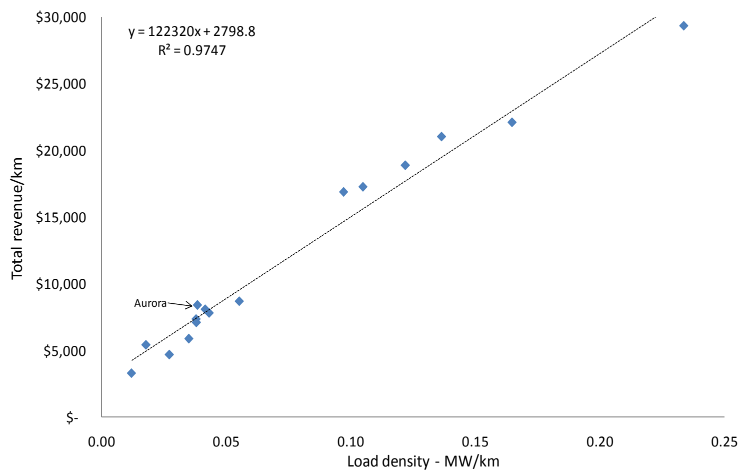
7.3.1 Load density

Analysis of the influence of operating conditions on network costs commences with an investigation of load density, the major network cost driver. The links between density, total costs, and assets (values – RAB, and quantities - poles) are explored in Figures 15, 16, and 17(a) and (b). For cost analysis, the appropriate measure of the asset base must be its value. Accordingly, the asset related analysis in this Report is based on the RAB value of assets. Any influence of asset age on values, and possibly on operating and maintenance and capital expenditure, is examined separately for Aurora in Sections XXXX.

To strengthen the financial analysis, a physical measure of assets is also presented, using pole data as a proxy for the quantity of assets invested.

In Figure 16, the relation between load density and total costs per km is examined. A clear, strong association between installed peak capacity per line length and total costs per km is evident. With an R-squared of 97 per cent, load density offers significant explanation for cost differences between the DNSPs.

Figure 16.**Load density and total costs/km**

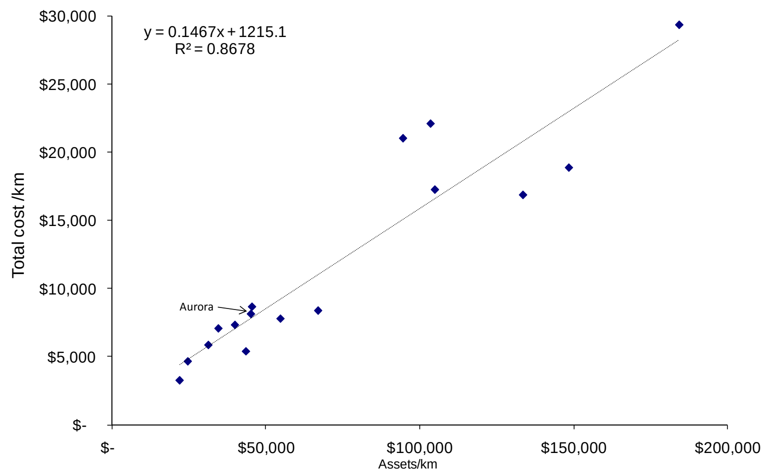


The strength of the relation reflects the pervasive effect of the principles of energy flow physics. Myriad factors may affect cost outcomes including climate, geography, vegetation, soil type, and age of network, but these tend to offer explanation of cost variations around the trend. Density alone determines the trend.

For the DNSPs, each increase of 0.01 in load density is associated with an increase in total costs of $1,230, in addition to the base cost of $2,898.

While the correlation between costs and density cannot be taken to imply causation, the link between assets, measured as the RAB, and average line costs depicted in Figure 16 can. Total revenue, based on the building block methodology, comprises around 70 per cent of capital costs based on the value of the asset base. The link between assets and costs is direct and robust. Based on the equation in Figure 16, average, total costs/km will rise by $1,467 per km for every $10,000 of asset investment per km. Note the similarity between the trend lines in Figures 17 and 18. The greater dispersion around the trend line in Figure 18 reflects a range of factors, particularly variations in the value of the RAB. Values may not always reflect the quantity of physical assets.

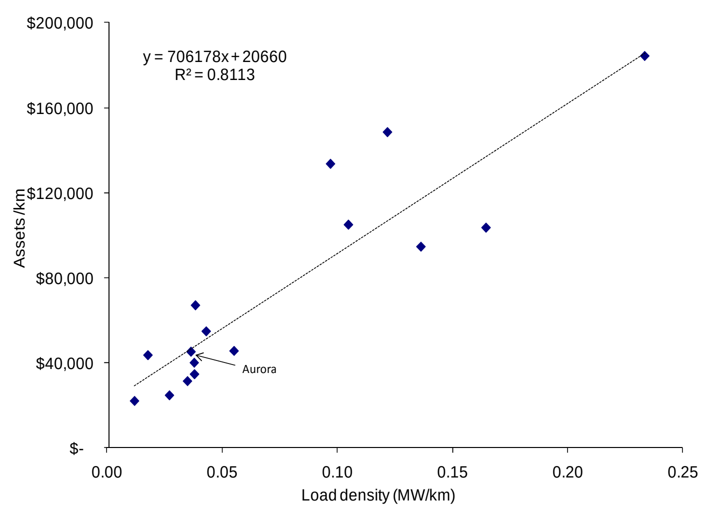
Figure 17. **Assets (RAB) and total costs/km**



Asset age is one factor driving a wedge between the quantity of assets and their value, with younger assets valued more highly than older depreciated assets. Another is the wasting value of the asset base as regulated capital expenditure remains below depreciation for several DNSPs. While the RAB for the Australian DNSPs on average, grew by 40 per cent between 2000 and 2009, for two DNSPs the value of the RAB actually declined. Despite substantial increases in output, RAB fell 5 per cent in one instance and three per cent in another.

There may be individual factors underpinning this variation, nevertheless, the ratio of the asset base does present an explanation for the greater dispersion of asset values around the trend compared to quantity of assets (using poles as a proxy) presented in Figure 18(b). Next, Figure 18(a) plots assets (RAB) per km against load density.

Figure 18. **(a) Assets (RAB)/km and Load density**

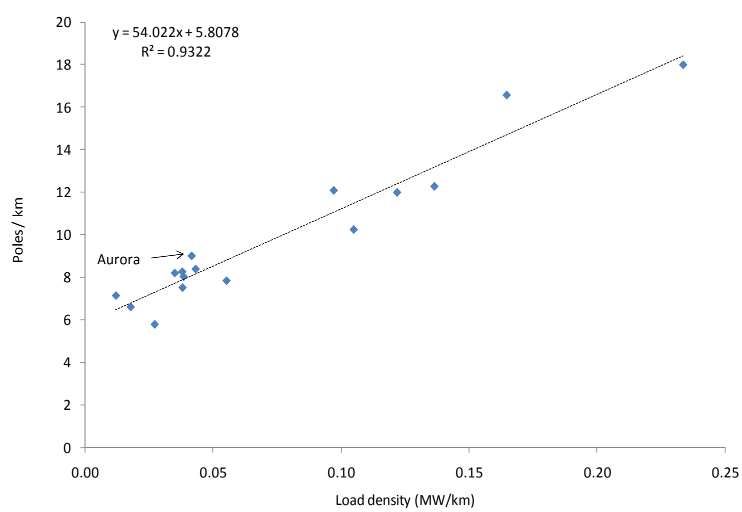


The trend between the two ratios is similar to those in Figures 15 and 16. Effectively, the density of the load determines the asset requirement for the network; this in turn reflects in total costs (the annual regulated revenue requirement). Factors affecting the valuation of assets are again likely to drive the variations around the trend.

On average, each additional O.01 MW/km rise in load density lifts the asset requirement by $706,178 per/km, in addition to the base cost of $20,660. The range of possible outcomes for the DNSPs is considerable. An urban high density network with a load density of 0.15MW/km has an asset requirement of around $126,590 per km, or around seven times greater than that invested by a low density rural network with a load density of 0.015MW/km at around $31,000 per km. These values are based on regulatory RAB; replacement cost assets would be around double these estimates.

To complete the link, Figure 18(b) plots poles per km, as a proxy for physical assets, against load density. The tighter fit around the regression line, compared to asset values in Figure 14(a) indicates the impact of asset age and valuation polices on relative asset values. The strength of this relation suggests the RAB may not provide the best measure of the quantity of assets to be operated and maintained; it would question the use of the RAB as a denominator for partial performance indicators.

Figure 18 (b) Assets (Poles)/km and load density



This examination of the effect of density on relative costs demonstrates clearly that costs normalised against line length will always present the low density rural networks as ‘low’ cost; in contrast, the ‘high’ cost DNSPs will always be those servicing urban and CBD networks. This outcome is a function of the assets required per line length, not the relative efficiency of the DNSPs. This can only be assessed by assessing their position relative to the regression line.

Comment: Aurora - total costs and load density

This comment on the level of appropriate total cost is presented only as a guide to Aurora's overall cost position since total cost, based on the building block methodology, also includes factors outside normal efficiency considerations.

Total cost per km for Aurora closely reflects the value of its RAB. This should not be taken to signify the asset value is appropriate, only that total costs are in line with the asset base. Noting Aurora's total costs lie somewhat above the trend line, we have compared the physical asset base, as proxied by pole numbers, to load density as presented in Figure 18(b). For its level of density, Aurora has an above average number of poles; as each pole represents an asset value this could offer an explanation for its RAB. Recall that Aurora does not have a sub-transmission system. It distributes only at low voltages which tend towards shorter distances between poles (hence more poles) than the higher voltage sub-transmission networks.

7.3.2 Customer type – load factor

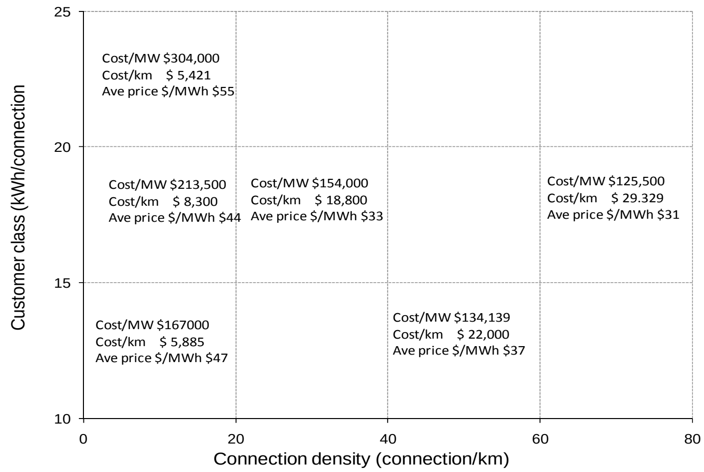
Cost is sensitive also to the type of end-user (described in this report as customer type and measured as kWh/connection). Average consumption levels provide a suitable proxy for customer type in the absence of more specific data. In some instances type based data is available, but as the definitions may vary widely the data are not appropriate for modelling purposes. Different types of consumers (domestic, commercial, or industrial) have divergent levels and temporal patterns of demand and energy consumption (network load factor), requiring different asset requirements.

In much the same way that location and density affect the type and quantity of assets required for each connection, the type of consumer connected also affects the amount and type of asset required. Whereas urban consumers are supported by more complex systems than those in rural areas, large consumers require more complex systems than smaller consumers. Consequently, rising average consumption levels tend to be linked to rising average asset requirements measured per connection.

For Australian DNSPs there is also an inverse relationship between customer class and connection density, with large industrial consumers tending locate in lower density rural areas – see simple matrix outlined in Figure 18.

The matrix indicates the complexity of the interrelationship between conditions, cost and price outcomes. Comparing customer class to connection density, the matrix presents average costs and prices for key combinations of these business conditions for the DNSPs. Costs presented are average revenue per MW peak capacity and per km of line length. Price is measured as average revenue per MWh energy conveyed.

Figure 19. **Matrix: Business conditions and cost and price**



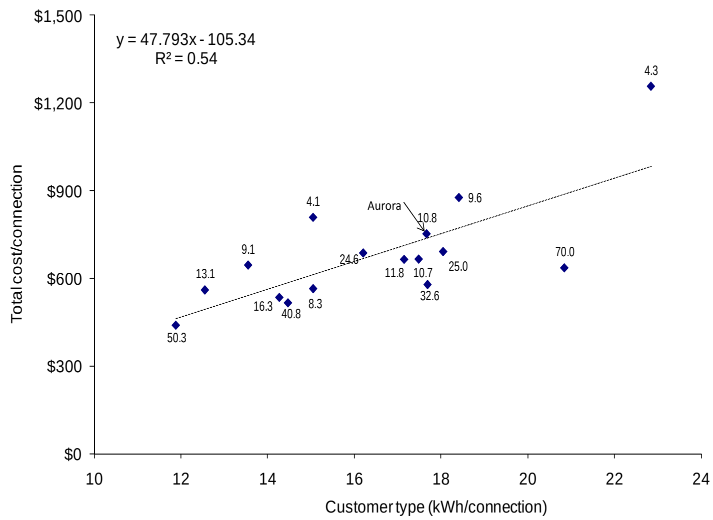
The boxes in Figure 19 that do not contain any cost and price detail indicate that no Australian network has that configuration. For example, there is no network that combines high connection density with high load factor, a pattern that has also been observed among US and New Zealand networks.

Moving from left to right on the X axis – connection density – we note that costs/MW generally decline but that costs per km rise significantly. Conversely, moving from the bottom to the top on the Y axis – customer class – capacity costs measured per MW tend to rise as average consumption increases but to decline when measured against network length. Large end users typically are more costly to connect (S/MW) but they also tend to be located outside the more densely populated urban areas, and hence have lower costs when measured against network length. In contrast, connecting a greater number of end-users to each length of network increases costs measured per km.

However, the presence of greater numbers of relatively small end-users tends to reduce the average cost of providing the capacity. Prices, on the other hand, tend to fall with both increasing customer density and load factor. Consequently, those networks with the highest prices will be those with relatively smaller consumers and lower connection density. The link between rising average consumption (signifying different types of customers) and increasing average connection costs is illustrated in Figure 20. Data labels show connection density.

Greater variability around the trend between class and cost outcomes, compared to density and costs, is a measure of the influence of other cost drivers, particularly the dominance of load density.

Figure 20. **Customer type and total cost/connection (connection density in brackets)**



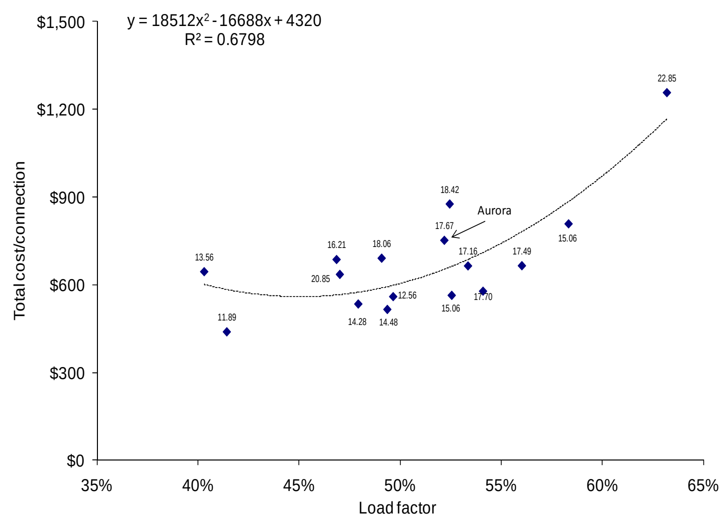
An upward trend between costs and consumption is clear, with total costs per connection rising by around $48 for every additional 1,000 kWh consumed. This link however is less robust than for costs and density. Effectively, the DNSPs fall into two groups: the rural lower density networks (above the trend) and the urban higher density networks (below the trend). That is, for any given level of consumption, providing a connection in a rural area may cost around $100 more per connection than in a higher density urban system. At the same time, the rise in total costs per connection for each additional 1,000 kWh of average consumption is the same for both rural and urban systems.

Customer type does not offer the same level of explanation as load density. It is, however, an important element in the cost model since the ratio of costs per connection is a widely used indicator of comparative performance.

A stronger measure of the influence of customer type on costs is provided by load factor. High load factors are typically associated with the more asset intensive requirements of large commercial and industrial consumers. Recall, supply to these end-users will be at 11kV or above, with dedicated zone substations, multiple circuits, and back-up assets.

Plotting load factor against total cost per connection, Figure 21 illustrates the rise in costs as load factor increases. Capacity has an advantage as a normaliser because it is less influenced by the impact of density than connections. The impact on costs is particularly notable at load factors above 50 per cent. At that point, there is an inflection in the cost curve with costs increasing more rapidly with each five percentage point increase in load factor.

Figure 21.**Load factor and total costs per connection**



Comment: Aurora: total costs and customer type

Aurora exhibits a cost outcome on the top side of the regression line for average consumption per connection but above the trend for load factor, demonstrating the conflict often present between different cost ratios. Above trend costs in Figure 16 (average consumption), reflect Aurora's relatively low connection density. Above-trend line costs in Figure 21, load factor, reflect Aurora's higher average consumption. DNSPs with high consumption end-users tend to be above trend while those with comparatively lower consumption levels tend to be below, an outcome in line with the dispersion of DNSPs in Figure 21 and reflecting the higher costs of connecting large consumers.

The analysis of total costs, load density, customer type, and load factor indicate a total cost outcome for Aurora reflective of its operating conditions and asset base. There is nothing untoward that merits closer attention.

7.4 Asset age

Electricity distribution networks are asset intensive operations; their prime function is to build and operate a physical network to convey electricity from the transmission busbars to the end-user. The scale of assets; Aurora has 220,000 poles, 30,000 transformers and 25,000 kms of conductors, and their long life-cycles requires detailed assessment of the asset age profile for cost-effective management over the long-term. Building on this knowledge engineering management can develop maintenance schedules and investment programs that optimise the performance of the network at the least cost.

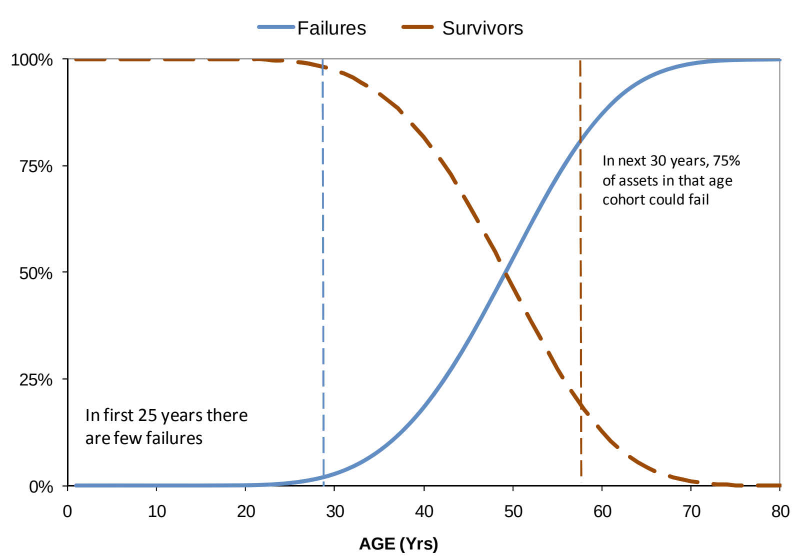
It is generally agreed that a group of fixed assets that are installed or constructed in a given year will not all fail at exactly the moment when they reach the end of the estimated average working life for that particular kind of asset. As the OECD observed[25]

> *"... the assumption of "simultaneous exit" is not realistic and retirements of assets will occur both before and after the average service life of the asset concerned. It is further agreed that the occurrence of retirements around the average service life will follow some kind of bell shaped curve; i.e. retirements will start slowly, accelerate to some modal retirement age and decelerate thereafter until they are all gone."*

It is possible to estimate the rate of probability of asset failure over time through the use of probability distribution functions (PDF). There is an extensive literature on the measurement and implementation of these functions; a short reference list is provided in Appendix B. The use of a probability distribution function enables asset managers to estimate the likely rate of failure as a basis for planning maintenance programs and replacement investment. The function used in this Report is the Weibull PDF which is widely used in asset management for electricity distribution networks.

Based on the Weibull distribution function, Figure 22 plots the probability of failure and survivor curves for assets with an expected average life of 50 years, typical for electricity distribution assets. Note the skew in the distribution of failures around the average life of 50 years because the average life is not mid-way between the date of installation and total expected life.

Figure 22. **Asset age and probability of failure**



[25] OECD Statistics Directorate. 1998 –Second Meeting of the Canberra Group on Capital Stock Statistics. Paris, September.

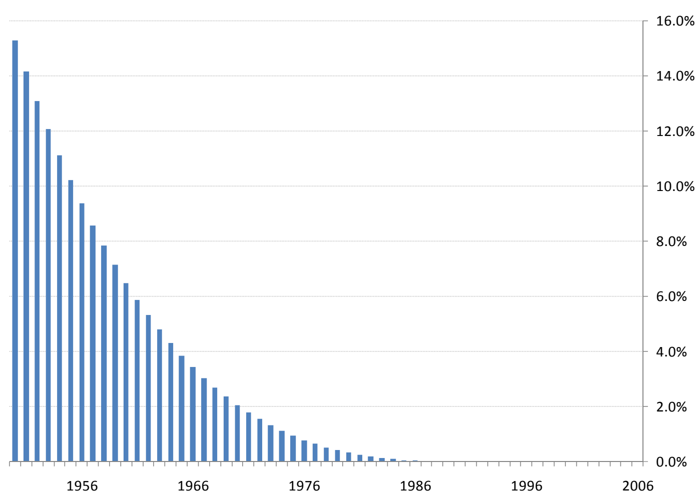
With electricity assets, typically few failures are experienced in the first 10-20 years, some assets will fail around 15 years while others may last for 80 years. Statistically, 63 per cent of assets remain in service at the average age of 50 years, not the 50 per cent assumed by the normal distribution.

Use of the normal distribution can provide a misleading assessment of the survival rate of the assets. A finding of a survival rate of 63 per cent at age 50 years (instead of the 50 per cent assumed by a normal distribution) could be taken to indicate inappropriate asset lifes; that is, the theoretical asset life used by the DNSP has underestimated the expected life. Adjusting asset lifes to fit an incorrect distribution function will result in misleading estimates of the likely probability of asset failure and replacement expenditure.

The lengthy period of failure-free service following initial installation can provide a false sense of network serviceability. The critical period is between 25 and 50 years when as many as 50 per cent of the assets may fail. The Australian DNSPs have now entered this more challenging period. This should not be taken to imply that asset replacement will be age based, only that the probability of failure will increase. Replacement will depend on the criticality of the asset to network performance and the cost-effectiveness of maintenance or refurbishment.

Figure 23 illustrates the rise in probability as assets age beyond 25 years. An asset aged 30 years may have an annual failure estimate of around one per cent, but this rises to three per cent for 40 years, nine per cent for 50 years and over 19 per cent for 60 years. Aurora has 18 per cent of its asssets aged between 40 and 60 years. In the five years to 2017, up to 50 per cent of the assets now aged 50 years and up could possibly fail.

Figure 23.**Probability of annual failure rate and asset installation date**



The estimates of the influence of Aurora's asset age profile on operating and capital expenditure detailed in Chapters 9 and 10 have been based on this failure rate analysis.

Part B: Network efficiency cost assessment

8 Aurora's distribution network

Part B presents the results of the cost structure analysis for the Aurora network; it is in two sections.

1. 2009 – based on actual expenditure data for year ending June 2009, excluding the mandated reliability/replacement expenditures for NSW and Qld. The capital expenditure analysis is based on gross data, including capital contributions; and
2. 2013-15 – based on an average of the regulated data. While there is no adjustment for mandated reliability expenditures, the capital expenditure analysis is based on gross data, including capital contributions.

Efficient and prudent operating expenditure is the focus of the analysis but capital expenditure has been reviewed to test whether observed operating expenditure has been off-set by over or under spending in capital investment.

Aurora: Network parameters relative to Australian total

This section presents an overview of Tasmania's (Aurora) distribution network parameters relative to the other jurisdictions. The ratios are set out in Table 11.

Table 11: Network parameters relative to Australian total

	Energy flow: GWh	Connections No.	System length km	Peak demand MW	Poles
Tas	3%	2.8%	3%	2.9%	3.3%
NSW	35%	34%	34%	34%	35%
Vic	23%	26%	19%	24%	18%
SA	7%	8%	11%	9%	11
Qld	22%	20%	24%	21%	24%
WA	9%	10%	10%	9%	10%

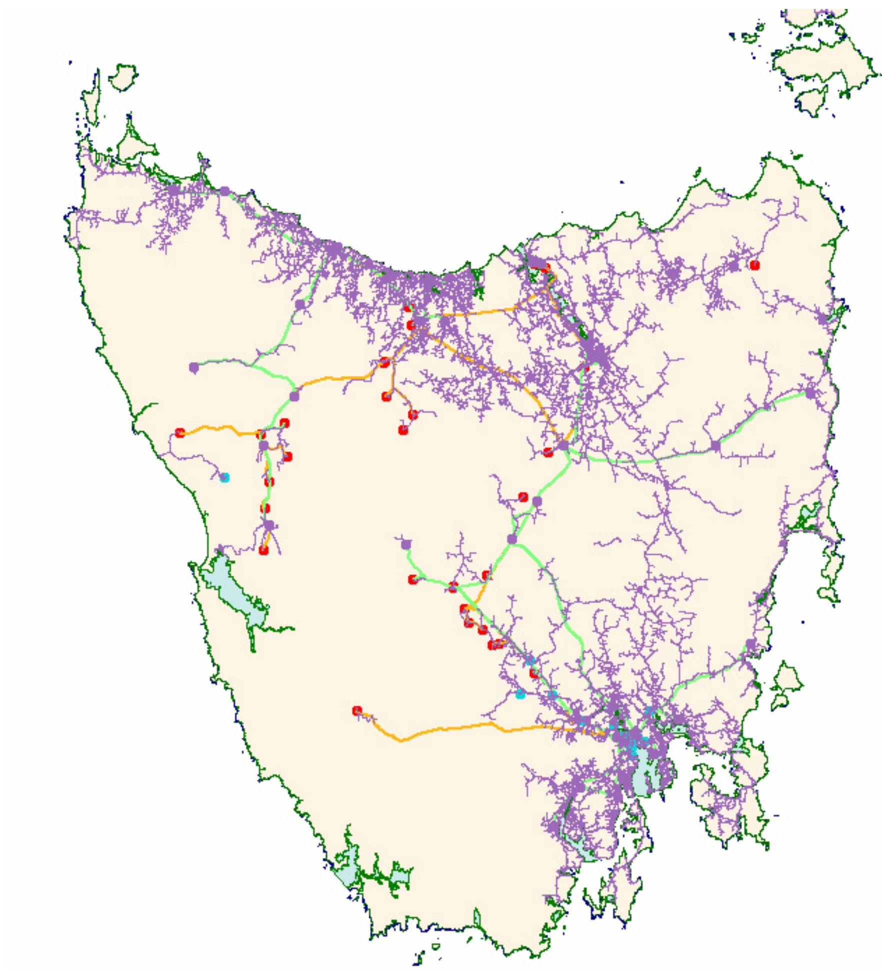
Variations between the ratios can influence the reliability of performance assessments based on simple network parameters. For example, Tasmania connects 2.8 per cent of Australia's end-users but they require 3.3 per cent of the poles installed. Consequently, costs measured per connection will be higher than if normalised against poles and distance, because the denominator – connections, is relatively lower than the denominators distance or poles. In contrast, Victoria has 26 per cent of connections but only 18 per cent of the poles; connection costs will be relatively lower than line costs.

8.1 Implications of hydro-based generation

Tasmania is the only state in Australia dependent on hydro-based generation; this has influenced Aurora's network in two ways. Hydro generators are typically smaller, but greater in number than, say, coal fired. With smaller generators, transmission connections are at a lower voltage, allowing the distribution network to connect directly to the transmission network eliminating the need for sub-transmission.

However, contrary to the prevailing view, the absence of sub-transmission does not reduce the length of the distribution network, only the distribution voltage. The ability to connect directly to the lower voltage transmission network means many of Aurora's distribution assets are often strung along the higher voltage network like beads on a string (Figure 24), rather than connecting directly to its own sub-transmission system..

Figure 24. **Transmission, distribution, and generation**



The distribution lines, shown in purple, are interspersed in a number of areas by the transmission network shown in yellow and green. Higher costs are involved in operating and maintaining these non-contiguous sections of Aurora's network.

9 2009 Expenditure analysis

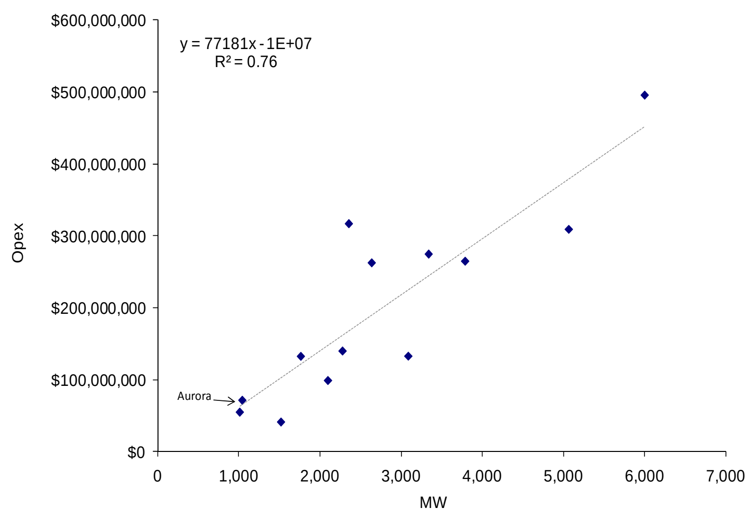
9.1 Operating expenditure

Operating expenditure is the only non-capital building block in the aggregate annual revenue requirement. Though not estimated by direct reference to the regulated asset base, its extent, age and condition nevertheless are key cost drivers of operating expenditure. The network cost structure model used in this Report assumes implicitly that the assets of the DNSPs share a similar age profile. That is, a weighted averaged asset age of 25 years. Should a network exhibit an asset age profile that deviates significantly from the industry average this could be expected to influence prudent levels of expenditure. The asset age profile of Aurora will be discussed following the analysis of operating expenditure and business conditions.

9.1.1 Scale and operating expenditure

The relation between total operating expenditure and peak demand MW has been investigated for economies of scale. Though not as pronounced as that between total revenues and MW, the scale benefits are measurable (Figure 25). Operating expenditure per 1000MW falls from $75,519 for a network with a peak demand of 1,000MW to $74,429 for networks with a peak demand of 6,000MW; a cost advantage of 1.8 per cent or $8,170,000 for the larger networks.

Figure 25.**Operating expenditure and scale – peak demand MW**



Aurora, with a peak demand of 907MW, the lowest of the DNSPs, is disadvantaged by these modest scale benefits available to the larger DNSPs; a position it shares with other small networks. The equation for the trend between scale (MW) and operating expenditure is:

Equation 1.Operating expenditure and peak demand MW

Operating expenditure = 77181x – 1633.9, R2 76%

Estimated operating expenditure Aurora = $69,871,832

Actual operating expenditure Aurora = $71,775,487

Range of appropriate expenditure +/-10% of estimate =62,9M - $76,9M.

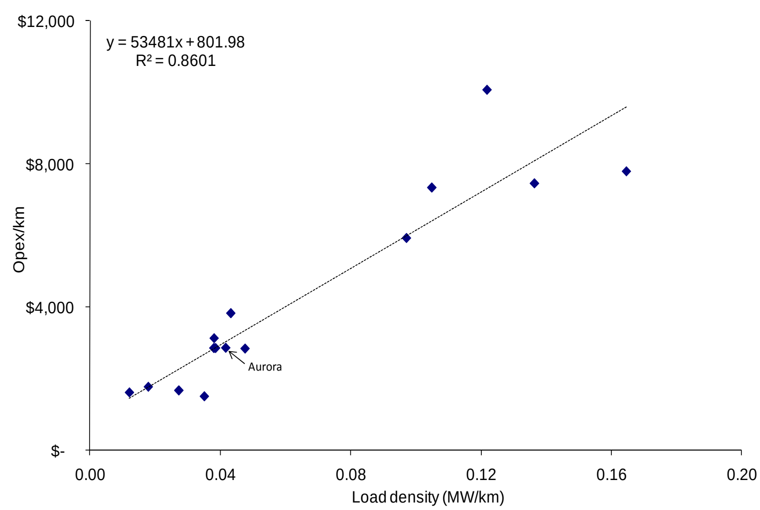
Aurora's actual expenditure is just above the model estimate but sits comfortably within the estimated range. With its scale disadvantage we consider this an acceptable outcome.

9.1.2 Load density and operating expenditure

Load density is the major cost driver for operating expenditure. Following the precedent established in Section 7.3.1, this section examines the relation between density, assets, and poles (a proxy for physical assets).

Figure 26 depicts the link between load density and operating expenditure/km. The regression line indicates a strong and positive relation between the two ratios and one that is similar to the link between total costs and density depicted in Figure 15.

Figure 26. **Load density and operating expenditure/km - 2009** [26]



At this level of analysis, load density offers an explanation for a large proportion of the variance in opex/km between the Australian networks. For each increase of 0.01 MW in load density, necessary operating expenditure is estimated to rise by around $534 per km. Again the range of appropriate

[26] Note this analysis excludes one of the Australian DNSPs. We are of the view the data has been defined differently to the other DNSPs. The statistical deviation from the industry trend was significant suggesting it could only distort any estimates based on the regressions.

expenditure for the low density rural networks ($1,619 per km) and the high density urban networks ($10,074 per km) is substantial.

Equation 2.Operating expenditure and load density

Based on the equation for Figure 25 the efficient and appropriate level of expenditure for Aurora in 2009 is estimated as:

Load density and operating expenditure/km

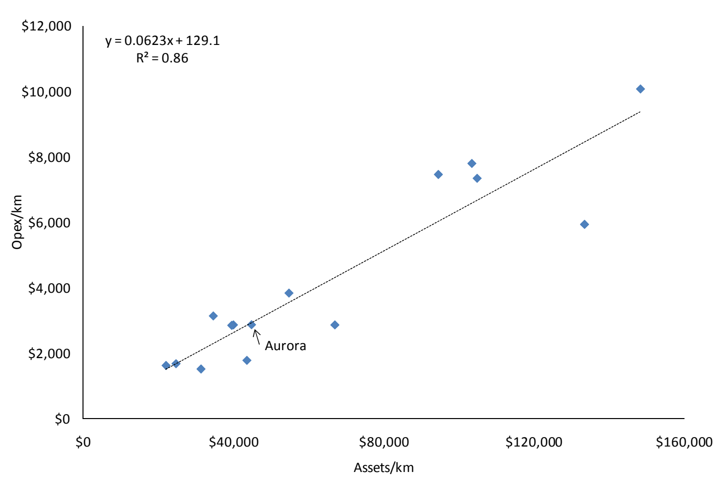
Average opex/km	= 53481x + 801.98, R2 86%
Estimated opex/km Aurora	= $3,048
Actual opex/km Aurora	= $2,865
Range of appropriate opex/km:+/- 10% of estimate	= $2,743 - $3,353
Estimated total operating expenditure	= $76,bM

Aurora's operating expenditure per km relative to its load density is less than the predicted level for efficient and prudent expenditure and comfortably within the estimated range.

9.1.3 Assets per km and operating expenditure

Recall the strong link between total costs and assets, measured per line length depicted in Figure 18(a). As operating expenditure relates directly to the asset base a similar link between expenditure and assets could be expected. Figure 27, plotting operating expenditure/km against assets/km confirms this. Note also the similarity of the trend line to that in Figure 28 between poles and expenditure. For each $10,000 of assets invested per km annual operating expenditure is estimated at $623 per km, over and above the base cost of $129.1.

Figure 27. **Assets/km and operating expenditure per km - 2009**



The DNSP well below the regression line has high load growth and proportionately younger assets, with commensurately lower operating expenditure.

Equation 3. Assets/km and opex/km

Average opex/km	= 0.0623x + 129.1, R2 86%
Estimated opex/km Aurora	= $2,947
Actual opex/km Aurora	=$2,865
Range of appropriate opex/km – +/10% of estimate	=2,652 - $3,241
Estimated total operating expenditure	=$73,814,329

Aurora's operating expenditure per km relative to its asset base is less than the predicted level for efficient and prudent expenditure and comfortably within the estimated range.

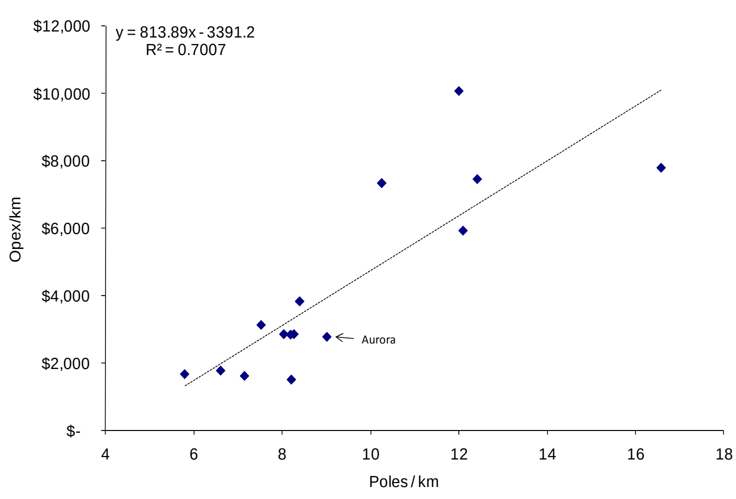
The dispersion of the DNSPs around the regression line in Figure 26 relative to Figure 27 most likely reflects variations in asset age. Younger assets will have a relatively higher value than older depreciated assets; at the same time however, they will require less operating expenditure. A closer link between the value of the asset base and operating expenditure could therefore be expected.

The next regression uses quantity of assets (poles) to test this.

9.1.4 Poles per km and operating expenditure

Figure 28, depicting the relation between operating expenditure and poles installed per line length exhibits a discernible link between costs and physical assets. The objective of Figure 28 is to demonstrate the link between the underlying physical assets and network costs.

Figure 28.**Poles/km and operating expenditure per km – 2009**

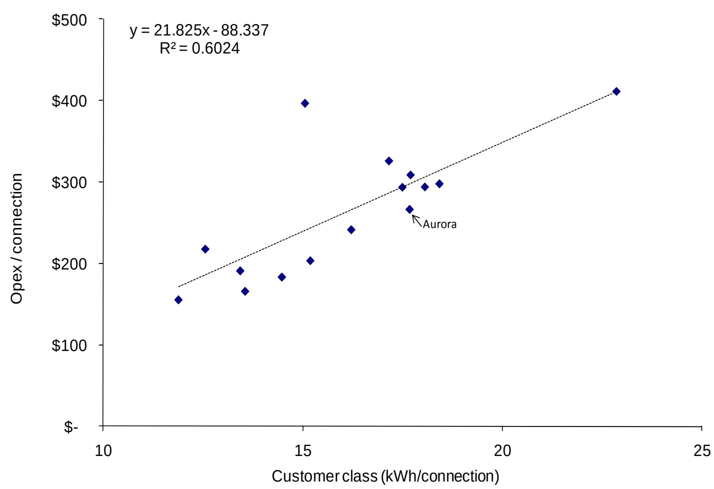


9.1.5 Customer class and operating expenditure

The type of end-user connected, represented by the variable customer class, is the other major operating condition; measured in this analysis as either average consumption per connection, or load factor. Figure 29, which plots opex/connection against customer class, indicates a positive relation between higher levels of average consumption and rising connection costs. End-users with large average consumption levels, whether mining, industrial or large commercial entities, require connection assets significantly different from those of smaller consumers.

While the influence of customer class on expenditures is less significant than that of density, a clear and positive trend is evident in Figure 29.

Figure 29. **Customer class and opex/connection**



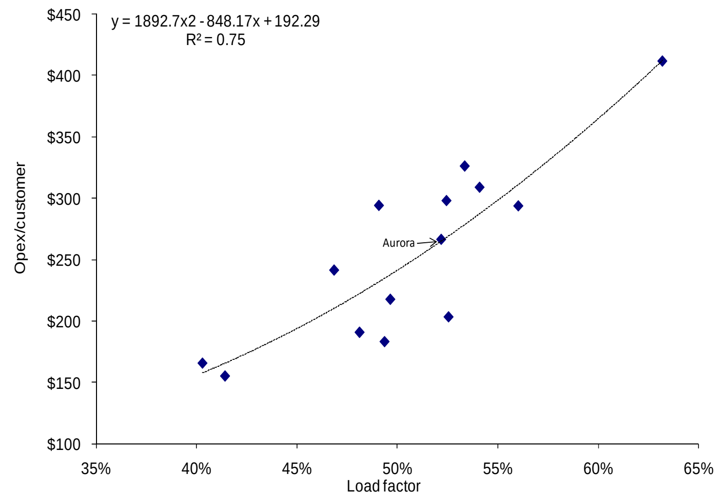
In general, for each 1,000 kWh increase in average consumption opex per connection rises by around $22. Aurora is well below the trend line, possibly due to the presence of the outlier on the upside which gives an upward bias to the regression line. In our view this results in an over-estimation of connection costs. Removing this network and re-estimating the equation reduces the estimated cost for Aurora by around $10 per connection or $2.3M total operating expenditure. Estimated appropriate opex/connection for Aurora based on the equation from the reduced model is:

Equation 4. Customer class and opex/connection (with outlier removed)

Average opex/connection	=23.439x – 125.66 R2 88%
Estimated opex/connection Aurora	=$288.51
Actual opex/connection Aurora	=$266.3
Range expected opex/connection +/10% of estimate	=$260 - $317
Estimated total operating expenditure	=$77.7M

Load factor will also influence the efficient level of operating expenditure per connection – Figure 30.

Figure 30.**Load factor and operating expenditure/connection**



Equation 5. Load factor and operating expenditure per connection

Average operating expenditure/connection =1892.7x2–848.17+192.29, R2 75%

Estimated opex/MW Aurora =$265.28

Actual opex/MW Aurora Energy =$266.30

Range expected opex/connection +/10% of estimate= $239 - $292

Estimated total operating expenditure = $71,502,685

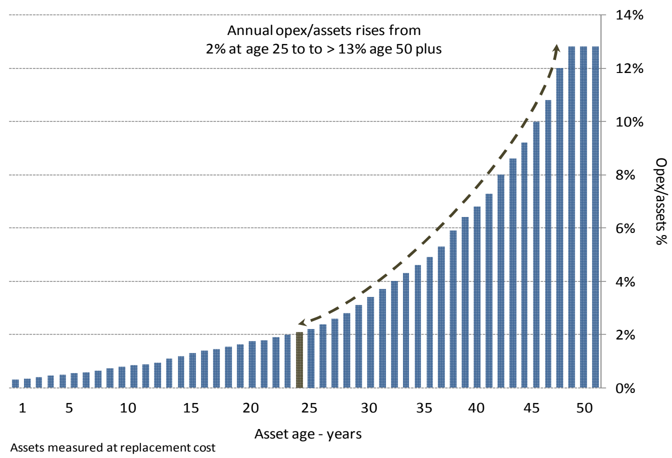
The estimates from equations 1-5 are not used directly to estimate an ‘efficient’ cost level; rather they will be used to estimate an envelope of efficient and prudent costs.

9.1.6 Asset age and operating expenditure

Load density and customer class provide significant explanatory power for the often large differences between the DNSPs in operating and capital expenditure. Other operating conditions, however, may cause variations around the trend. One major factor is the age of the asset base and its condition.

Expenditure for operating the network is not a static function of the value of the asset base, and it can vary widely depending on network age and condition. Engineering estimates of the ratio of operating expenditure to the asset base extend from almost zero for new assets up to 13 per cent of replacement cost per year for assets nearing the end of their economic life27, Figure 31.

Figure 31. **Asset age and operating expenditure**



Cost-effective asset management strives to achieve a balance between planned and unplanned maintenance. Maintaining a weighted average asset age of around 25 years for network assets with an expected life of 50 years is intended to meet this objective. It avoids replacing assets prematurely while at the same time ensuring reliability by constraining the proportion of older assets with their higher probability of failure rates. An average age of 25 years would equate to annual operating expenditure of two per cent of replacement cost (or approximately four per cent of ODRC).

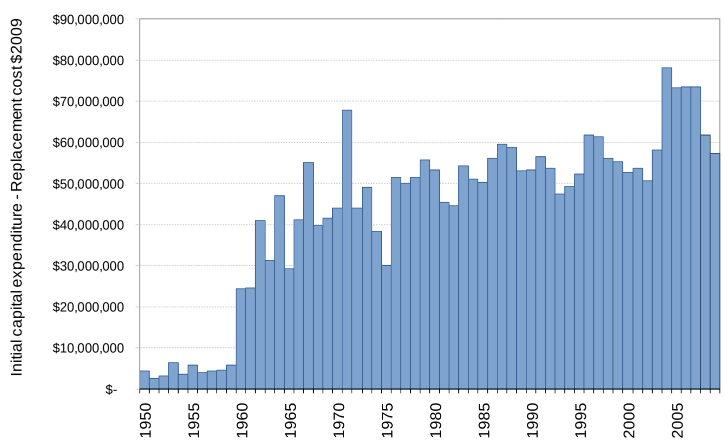
The impact of asset age on operating expenditure varies between the Australian DNSPs. Networks with a weighted average asset age in excess of 25 years, that is, with a higher proportion of older assets, can be expected to exhibit a higher level of operating expenditure, all else equal. These networks tend to be those in the older states such as NSW, or those with low load growth such as Tasmania or South Australia. Figure 32 presents the asset age profile for Aurora. The bars represent the capital investment (at replacement cost) in each year where the assets remain in service.

Aurora's asset investment in this profile commences in 1946 and extends to 2009. Investment first peaked in the decade beginning 1961; this was followed by relatively stable growth followed, punctuated by small declines in the mid-1980s and mid 1990s. This last decline coincided with substantial and unplanned load growth and the commencement of the replacement cycle based on rising probability of failure.

[27] SKM in Aurora Supplementary Submission to IPART, Appendix B, October 2003

There was, however, insufficient capability in Aurora's expenditure budget to accommodate both unexpected load growth and upgrading of the ageing asset base; growth took precedence over replacement. Moreover, as Aurora stated in its submission to the OTTER in 2006, the amount of work required for replacement was found on audit to be greater than expected.

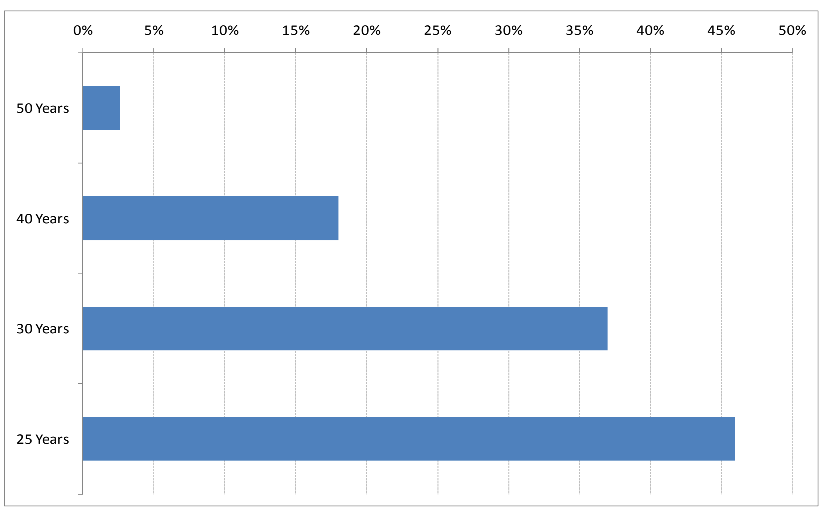
Figure 32.**Asset age profile-Aurora - Replacement cost $2009 million28**



Source: Aurora Energy

Delay to refurbishment or replacement of older assets has increased Aurora's proportion of older assets; 18 per cent now exceed 40 years and 36 per cent exceed 30 years, (Figure 33).

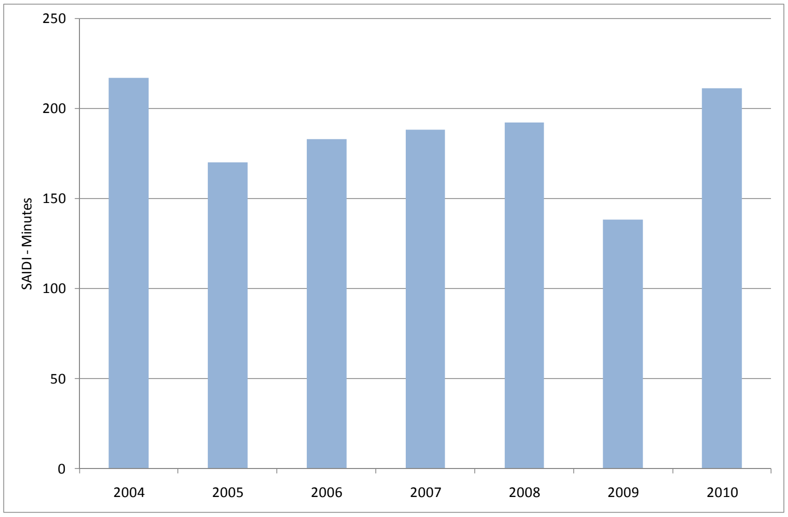
Figure 33. **Asset age - Estimated at replacement cost ($2009)**



[28] Replacement costs are based on unit costs for 2009 – This provides a total replacement cost for Aurora's asset base of around $2.6B.

That is, 36 per cent of the asset base now falls within the range of 5.6 per cent to 18 per cent of ODRC for annual operating expenditure. Even with the increase in expenditure from 2004 the outcome has been a rising trend in unreliability since 2005 (Figure 33).

Figure 34.**Reliability - SAIDI: 2003 - 2010**

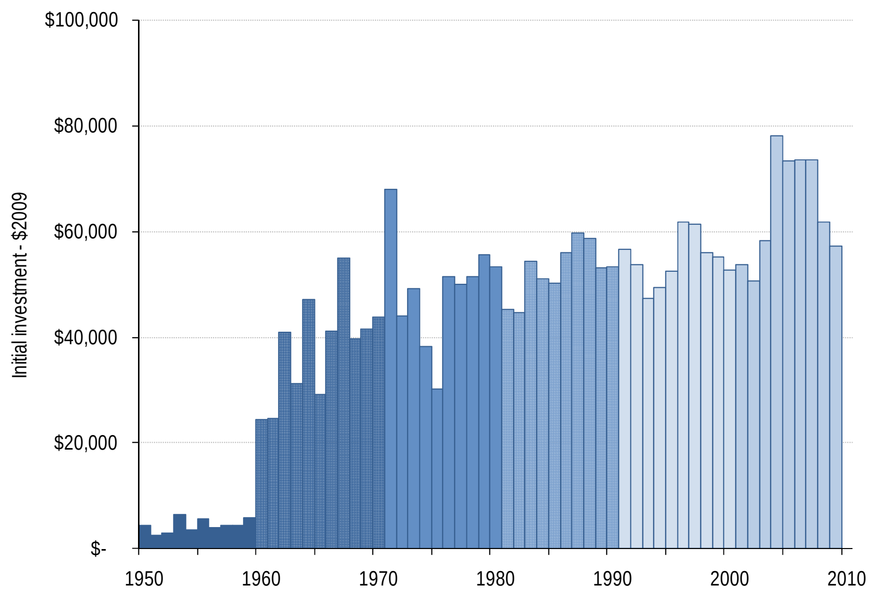


It does not follow that these aged assets require replacement on an age related basis. Current experience indicates that assets may well exceed their estimated life but it should be expected that savings in capital expenditure will to a certain extent be offset by rising maintenance costs. As an asset reaches middle age, the cost of condition monitoring to optimise its cost-effective life accelerates. Ageing assets require more frequent monitoring and, where necessary, maintenance or refurbishment. The impact of ageing assets and the probability of asset failure on estimated operating expenditure for Aurora is illustrated in Figure 35.

Escalating maintenance as assets move into the latter stage of their life means older assets have a disproportionate influence on expenditure. Accordingly, the weighted average age of assets may not always present an appropriate guide to expenditure. The weighted average asset age of 23.1 years for Aurora is commensurate with annual opex of 1.8 per cent of replacement cost. However, due to the asymmetric nature of the opex/asset ratio with regard to asset age, when the proportion of older assets is taken to account the opex requirement rises to 3.2 per cent of replacement cost or over six per cent per annum for ODRC.

Note, the engineering estimate of age related operating expenditure includes assets aged up to 50 years only. The uniform rate of 12.8 per cent indicated between 1946 and 1960 in Figure 35 therefore represents only the minimum likely cost.

Figure 35.**Asset age profile - Aurora - Replacement cost $2009 Million**



Age - years	**60**	**50**	**40**	**30**	**20**	**10**
Opex assets ratio						
Replacement	12.8%	9.1%	4.2%	2.0%	1.1%	0.6%
ODRC	25.6%	18.2%	8.2%	4.0%	2.2%	1.2%

Estimates of annual maintenance expenditure as high as 13 per cent of replacement cost, or 26 per cent of ODRC, for equipment over 50 years, may appear excessive. However, as assets move into the second half of their life there are significant changes in the type of maintenance required. More intensive maintenance procedures such as drilling and treatment and pole staking replace low cost routines such as line monitoring and pole inspection.

To illustrate the costs behind these changes Table 12 lists several types of maintenance and associated costs for a standard residential timber pole.

Table 12:Residential timber pole maintenance: type and cost

Item	**Cost $2009**
Pole - replacement	7,500
Line inspection	25
Pole inspection	75
Pole stake	1000

Escalating costs as maintenance moves from line inspection to staking reflects the additional time, labour, and capital required to maintain poles as they age.

While as many as 60 poles per day may be inspected in urban areas and 20 per day in rural areas, staking requires substantially more time and resources. Each staking typically requires two technicians plus a mechanical stake driver and dedicated truck-transporter - see Figure 36. In urban areas the team can typically stake around six poles per day but around half that in the less dense rural areas.

Figure 36. **Pole staking – LV residential area**[29]

9.1.7 Aurora's asset age and prudent operating expenditure

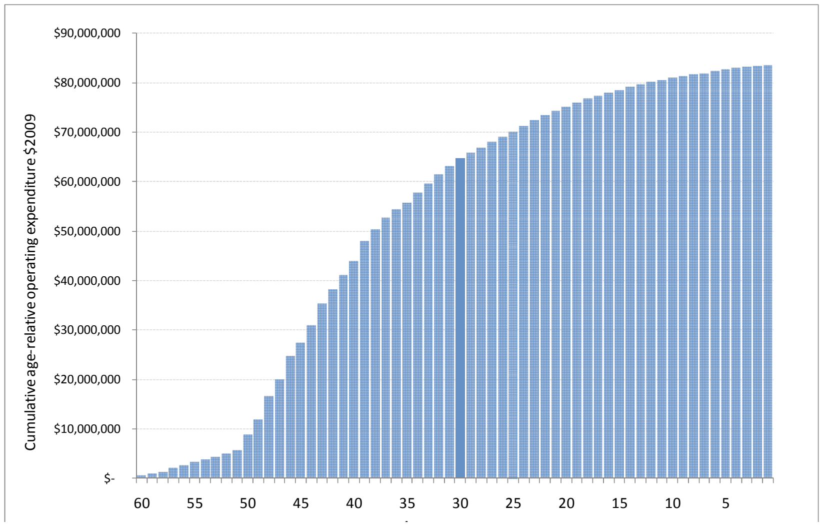
Aurora's weighted average asset age of 23.1 years, implies an opex/asset ratio of 1.8 per cent of asset replacement value (estimated in this report at $2.6B in 2009 dollars). However, the higher weighting of operating expenditure for assets aged over 30 years results in an estimated opex/assets requirement of 3.4 per cent, or $83M at replacement value, in 2009 dollars ($160M valued relative to RAB). Of this total, $65M ($130M) relates to assets aged 30 years and over (Figure 37).

That is, assets aged over 30 years represent 78 per cent of estimated operating expenditure although they represent only 36 per cent of the assets. Older assets can be maintained beyond their estimated life, but it can come at a not insignificant cost.

If the older assets are not refurbished or replaced within the 2012-17 pricing period the annual operating expenditure requirement could rise by a further $20M in 2009 dollars (assets valued at replacement cost or $40M relative to RAB).

[29] Photo by Benchmark Economics, NSW, 2007.

Figure 37.**Cumulative operating expenditure and asset age**



The proportion of Aurora's aged assets lifts the level of prudent operating expenditure by approximately $80 million in 2009 dollars, nearly doubling the proposed operating expenditure of $86 million. This brings the estimated total for operating expenditure in 2009 to $160M.

9.2 Capital expenditure

The scope of this report does not extend to a full analysis of the prudent and appropriate level of capital expenditure for Aurora. This section is intended only to investigate whether Aurora's 2009 operating expenditure was offset by an over or under spend in capital expenditure.

Capital expenditure has two main components: load growth and replacement. This duality creates greater variability around the trend than for operating expenditure. Recent concerns at declining reliability have added an additional cost driver, security of supply. Moreover, the jurisdictions have not responded uniformly to the challenge of supply reliability; while some have mandated increased levels of reliability, others have not. Divergence around the capital expenditure trend in the following analysis therefore reflects a greater range of factors than operating expenditure.

Density, as discussed previously, has a pervasive impact on the type of asset selected and, in turn, cost outcomes. Whereas low density rural areas may be serviced by a single circuit low voltage line with widely spaced poles and little redundancy at a cost of $1,295/km, a high density urban supply consisting of multiple circuits and higher levels of redundancy may cost up to $12,000/km.

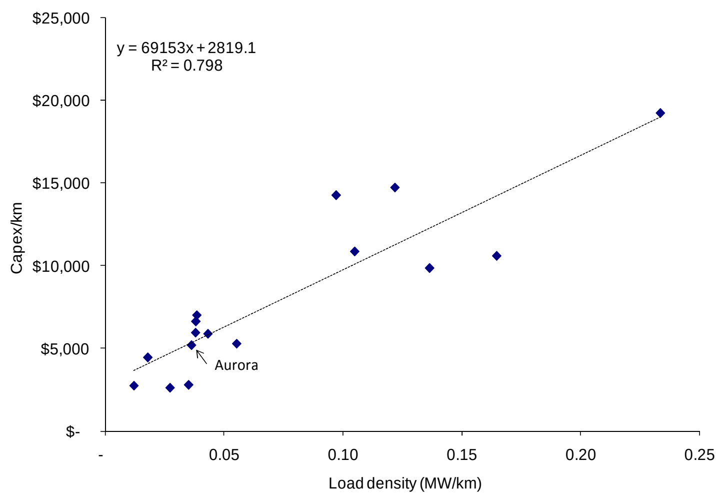
9.2.1 Load density and capital expenditure

Figure 36 comparing capex/km against load density depicts a positive trend between the two ratios, with capex/km rising as load density increases. Though the trend is clear, there is more variance around the regression line, compared, say, to opex and density (Figure 14).

Several factors account for this dispersion; asset age profiles may differ, load growth has not been uniform, accounting practices for expensing and capitalising expenditures vary, and finally not all jurisdictions have imposed additional reliability standards with related higher expenditures.

The outstanding above-trend networks in Figure 38 reflect increased expenditures mandated for improved reliability. On the other hand, the outstanding below-trend networks have received tight capital expenditure allowances. For two of the DNSPs the constraints have been sufficient to reduce the regulated value of the asset base in 2010 to a level lower than that in 2000 - despite 22 per cent growth in peak demand. This decline has been accompanied by deterioration in network reliability.

Figure 38.**Load density and capex/km**



While there is dispersion around the trend in Figure 38, load density still offers an explanation for a considerable amount of the variation in capex/km between the Australian DNSPs. Aurora's capital expenditure ratio is on the trend line, suggesting its level of capital expenditure has not been used to off-set its efficient level of operating expenditure.

9.2.2 Assets/km and capex/km

Figure 39. **Assets/km and capex/km**

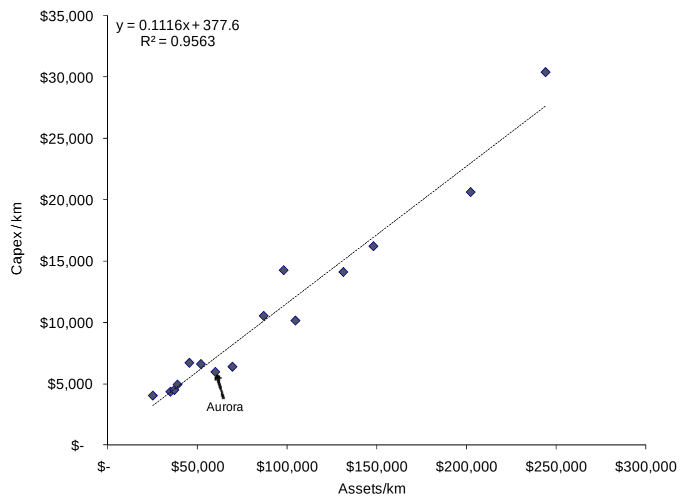


Figure 39, plotting capex/km and assets/km, confirms the strong relation between the asset base and ongoing investment. With a level of capital expenditure below that appropriate to the value of its asset base there is no evidence of over-investment.

9.2.3 Customer class and capex/connection

Customer class influences the level of capital expenditure through its impact on the type of assets necessary to provide supply to different end-users.

Figure 40. **Customer class and capex/connection**

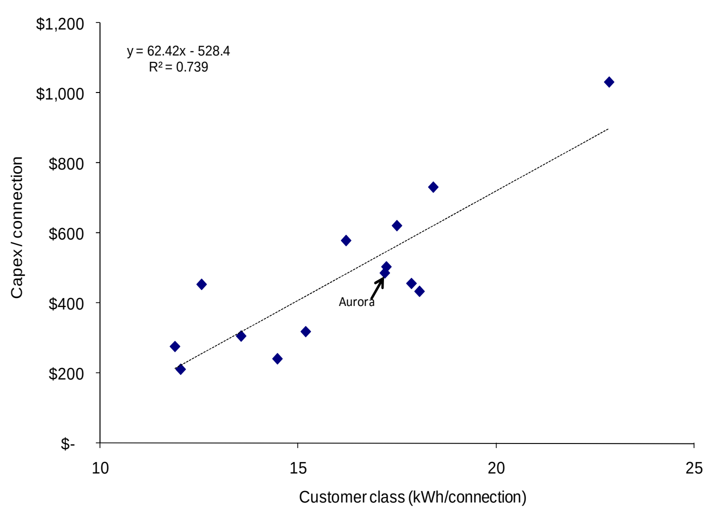


Figure 40 depicts the relation between customer class and capex/connection, and reveals a clear upward trend between the two ratios. Capex per connection rises from around $200 for an end-user with an average consumption of 13,000 kWh up to $1,100 for an end-user with an average consumption in excess of 23,000 kWh. Networks with low average consumption levels have a predominantly urban residential and commercial load, with high gas penetration. In contrast, a network with a very high average consumption level would likely be a rural network servicing large industrial and mining entities. Indeed, networks to the high side of the trend line tend to be those servicing rural areas and those below the trend servicing urban and CBD areas. For any given level of consumption, rural networks typically invest between $70 and $100 per connection more than the urban service providers.

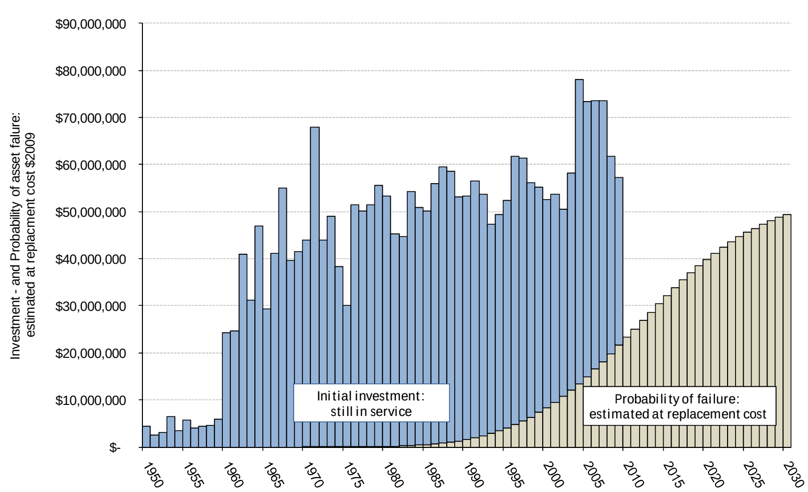
The outliers observed in Figure 38 move closer to the trend in Figure 40 suggesting the type of customer they connect has a greater influence on their level of capital expenditure than load density. Growth in the mining sector has generated considerable additional investment to upgrade and augment connections; this investment is a strong determinant.

Aurora has a cost ratio below the trend line adding weight to the observation that it has not used capital expenditure to offset its operating expenditure. Note this capital expenditure analysis does not take account of variation in asset age profiles between the DNSPs.

9.2.4 Aurora's asset age and prudent capital expenditure

In common with other industrialised economies, the initial rollout of Aurora's electricity distribution network took place during the 1960s and 1970s. Once the network was established, further investment tended to be driven by load growth. By the mid-1980s, the initial assets passed the mid-point of their expected life and the second cycle of investment began (Figure 41).

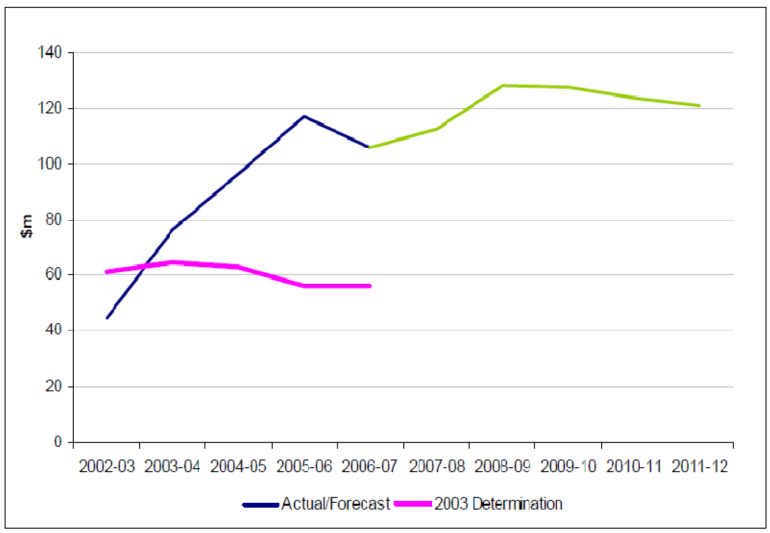
Figure 41. **Investment and probability of failure cycles**



Based on an estimated probability of failure for Aurora's network, potential replacement investment rose from a 1 per cent of annual capital expenditure in 1985 to 16 per cent in 2000 and potentially to 38 per cent in 2009. There will now be a period of continuous increase in probable failure rates until a plateau is reached around the beginning of 2030.

At the same time as the replacement cycle accelerated, a period of unexpectedly strong demand growth emerged and one that had not been factored into the regulatory expenditure allowances. While peak demand growth rose by over 25 per cent between 2000 and 2007, real regulated capital expenditure remained more or less constant. By 2004, cost pressures from strong demand growth and ageing assets forced Aurora to lift its capital expenditure 75 per cent above its regulated allowances (Figure 42).

Figure 42.**Regulated and actual capital expenditure June 2006 dollars**



Source: OTTER, Final Report 2007

While the sharp rise in capital expenditure was unprecedented for Aurora it was not the only DNSP in this situation; similar substantial capital expenditure increases had been granted in Qld, NSW, Western Australia, and also the UK.

The sharp expenditure increase in 2004 allowed Aurora to expand its network in line with load growth and to attend to the more pressing ageing assets. However, assets will continue to age through the next price period. This has been estimated to lift the proportion of assets at risk of failure by around 60 per cent from the level in 2009. Whether the projected additional expenditure is directed to higher levels of monitoring and maintaining the ageing assets, and, if necessary, their replacement, expenditure levels must be increased.

Aurora now has an estimated 36 per cent of its assets aged over 30 years of which 18 per cent are over 40 years. At age 30 there is a three per cent per annum probability of failure, at 40 years it is 8 per cent, and up to 19 per cent for assets 50 years. There may be some that last much longer, but as in all things, the exception does not disprove the rule.

The probability of failure for Aurora's asset base in 2009 is estimated at $21.5M, valued at $2009 unit costs.

9.3 2009: Efficiency estimates

9.3.1 Estimate of efficient and prudent operating expenditure

Table 13 draws together estimates of appropriate and efficient operating expenditure for Aurora based on 2009 data and derived from the equations based on network operating conditions and detailed in Chapter 9.

Table 13:Efficient operating expenditure: Estimates from Equations 1, 2,3, 4

Indicator	Predictor	Estimate	Range	2009 Actual
Operating expenditure	Scale - MW	$70.0M	$$63M-$77M	$71.8M
Opex/km	Load density	$3,048	$2,743-$3,353	$2,865
Total opex		$76.4M	$68.7 - $84.2M	$71.8M
Opex/km	Assets/km	$2,947	$2,652 - $3,241	$2,865
Total opex		$73.8M	$66.4 - $81.2M	$71.8M
Opex/connection	Customer class	$288.5	$260 - $317.3	$266
Total opex		$77.7M	$70 - $85.4M	$71.8M
Opex/MW	Load factor	$264.2	$238 -$291	$266
Total opex		$73.4	$66.0 - $81.0M	$71.8M

These equations provide the envelope of prudent and efficient operating expenditure from which the final estimate for Aurora is derived – Table 14.

Table 14: Efficient and envelope for operating expenditure 2009

Scale	Load density	Assets/ km	Customer class	Load factor	Efficient cost estimate
$71.8M	$76.4M	$73.8M	$77.7M	$73.4M	**Average = $74.6M**
					Range +/- 10% $67.5 - $82.4M

Efficient and prudent operating expenditure for Aurora in 2009 is estimated at $74.6M; based on assessment of its network cost structure.

Prudent operating expenditure for 2009 would also include an additional $83M, or 3.14 per cent of the asset base valued at $2009 replacement cost, to take account of the ageing of the asset base.

This age related estimate, at management discretion, could be off-set by refurbishment or replacement expenditures.

9.3.2 Prudent and efficient capital expenditure

The purpose of analysing capital expenditure is to assess whether there was any trade-off with operating and maintenance expenditure, rather than to provide an estimate of prudent investment. We find the actual capital expenditure allowance in 2009 for Aurora was in line with its business conditions and industry average investment levels. Accordingly, we accept that capital expenditure does not include any off-set for higher/lower operating and maintenance expenditure.

The NER requires proposed operating expenditure not only to be efficient but also to be prudent. That is, expenditure should relate not only to the level of DNSPs in similar circumstances but equally to the age and condition of the network. Given the estimated probability of failure for Aurora's network in 2009, it is estimated that an amount of $21.5M ($2009) would be required to ensure future reliability by refurbishing or replacing aged assets.

10 2013-15 Expenditure analysis:

10.1 Operating expenditure

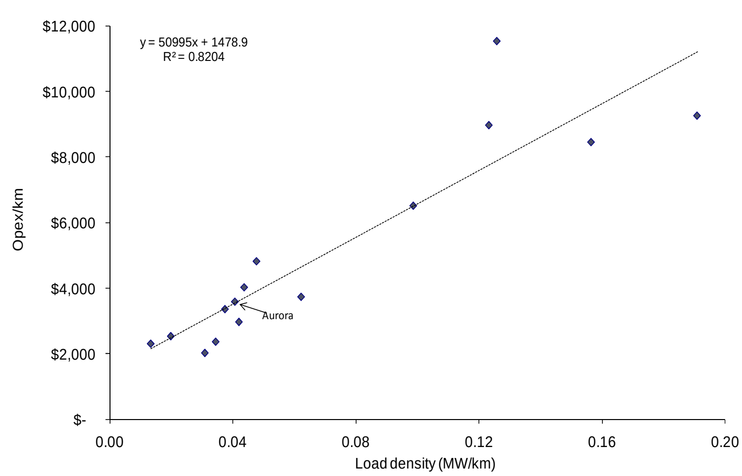
This section examines the efficiency and prudency of Aurora's proposed forward expenditures for the 2012-2017 price period. A three year average of forward data has been selected for the years 2013 – 2015; 2013 is the first year of the new price period for Aurora while 2015 is the last year for which data are available for the other DNSPs. The structure of this section follows that of Section 9.1 for 2009 expenditure.

10.1.1 Load density and operating expenditure

Figure 43 depicts the link between load density and operating expenditure/km. The regression line indicates the same strong and positive relation between the two ratios as that in the 2009 expenditure analysis.

Load density continues to offers an explanation for a large proportion of the variance in opex/km between the Australian DNSPs. Again there is a wide range of appropriate expenditure, from $2,036 per km for the low density rural networks to $11,300 per km for the high density urban networks.

Figure 43.**Load density and operating expenditure/km 2013-2015- $2009** [30]



For each increase of 0.01 MW in load density, operating expenditure is estimated to rise by around $510 per km with an intercept of $1,479. These costs present a change from the 2009 data analysis. In that year the slope of the trend line indicated a rise of around $534 per km for each 0.01 increase in load density with an intercept of $808. The uplift in the intercept ($1,478 up from $808), suggests a structural change in the basic level of operating

[30] Note this analysis excludes one of the Australian DNSPs. We are of the view the data has been defined differently to the other DNSPs. The statistical deviation from the industry trend was significant suggesting it could only distort any estimates based on the regressions.

expenditure between the two periods. This most likely reflects the increase in regulatory allowances between the 2008-2012 and 2009-2015 determinations. The lower rate of increase per km ($510 per km in the latter period down from $534 per km in 2009) could reflect a number of factors. The constrained expenditure allowances to the highest density DNSPs would tend to pull the top of the trend line lower, reducing the measured rate of increase in operating expenditure for each additional km. This should have little impact on low density DNSPs including Aurora.

Equation 6.Operating expenditure and load density - 2013-15

Based on the equation for Figure 55 the efficient and appropriate level of expenditure for Aurora through the period 2013-15 would average:

Load density and operating expenditure per km

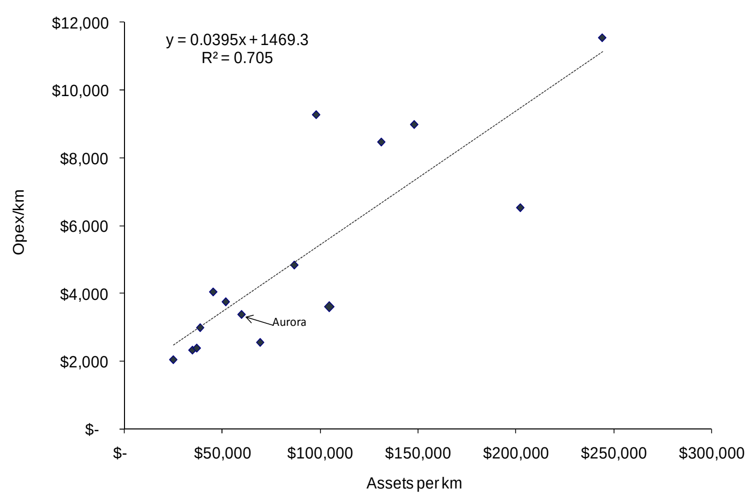
Average opex/km	=50995x +1478.9, R2 82%
Estimated opex/km Aurora	= $3,388
Actual opex/km Aurora	=$3,371
Range of appropriate opex/km:+/- 10% of estimate	= $3,049 - $3,726
Estimated total operating expenditure	= $86.6M

Aurora's operating expenditure per km relative to its load density is below the estimated level for efficient and prudent expenditure and comfortably within the estimated range.

10.1.2 Assets per km and operating expenditure

Figure 44 plots operating expenditure/km against assets/km. For each additional $10,000 of assets invested per km annual operating expenditure is estimated to rise by $395 per km, over and above the base cost of $1469.3.

Figure 44.**Assets/km and operating expenditure per km: 2013-15 - $2009**



Again note the sharp lift in the intercept from $142 to $1,497 between 2009 and 2013-2015, providing some measure of the magnitude of the increases awarded at the commencement of the each regulatory price round. At the same time, the rate of increase in operating expenditure per km associated with rising asset investment has dropped from $622 per $10,000 to $395. Nevertheless, when combined, the effect is to lift the efficient rate of operating expenditure per km by around 30 per cent between the two time periods.

Outliers on the upper side of the trend line in Figure 43 are those DNSPs with an eroding regulated asset base; this provides a somewhat misleading estimate of the efficiency of their operating costs. At the same time DNSPs with rapid load growth will have proportionately younger assets, with commensurately lower operating expenditure.

Equation 7.Assets/km and opex/km

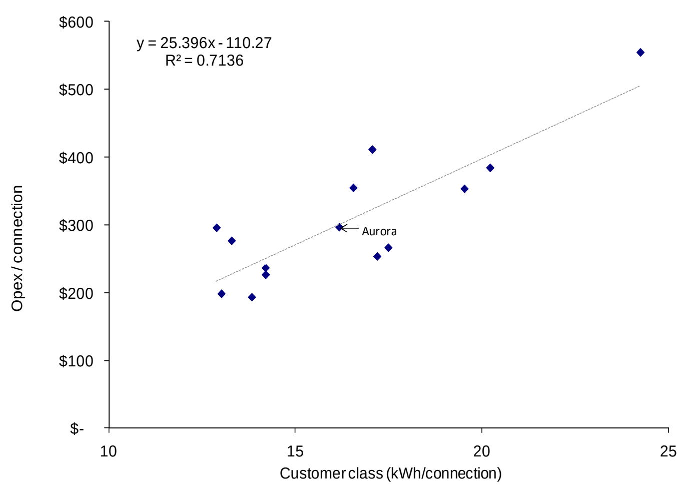
Average opex/km	= 0.0395x + 1469.3, R2 70%
Estimated opex/km Aurora	=$3,842
Actual opex/km Aurora	=$3,371
Range of appropriate opex/km – +/10% of estimate	= $3,458 - $4,226
Estimated total operating expenditure	=$98.2M

Aurora's proposed operating expenditure per km relative to its asset base is below the efficient and prudent level of expenditure predicted by the model and comfortably within the estimated range.

10.1.3 Customer class and operating expenditure

Figure 45, plots opex/connection against customer class.

Figure 45.**Customer class and opex/connection**



There is less dispersion around the trend than in Figure 43 plotting assets against density providing some indication of the influence of the asset base valuations. In general, for each 1,000 kWh increase in average consumption opex per connection rises by around $25.4 up from $23.7 in 2009. The intercept, a negative in this model, however falls from $131 in 2009 to $110 in 2013-15, contributing to an average 30 per cent increase in connection cost.

Aurora has a cost ratio that meets the industry trend line for efficient and prudent expenditure.

Equation 8.Customer class and opex/connection

Average opex/connection =23.439x – 110.3 R2 72%

Estimated opex/connection Aurora =$300.5

Actual opex/connection Aurora = $296.3

Range expected opex/connection +/10% of estimate = $270 - $330

Estimated total operating expenditure =$87.4M

Load factor also exhibited a significant influence on the efficient level of operating expenditure per connection in the 2009 analysis. This does not appear to be so for the forward expenditures, with a marked fall in the coefficient of determination (R^2) between the two periods. The regression equation for load factor is no longer sufficiently robust for estimation purposes.

Sharp price increases predicted in delivered energy, combined with energy efficiency and renewable energy programs, have impacted on projected energy flows but not on the demand for peak capacity. Accordingly, changes in predicted energy flows, and hence load factor, vary considerably between the DNSPs bringing substantial changes to predicted load factors. Load factor will not be included in the suite of estimation equations for the 2013-15 analysis.

In line with the 2009 analysis, the estimates from equations 5-7 will not be used directly to estimate an 'efficient' cost level; rather they will be used to estimate an envelope of efficient and prudent costs.

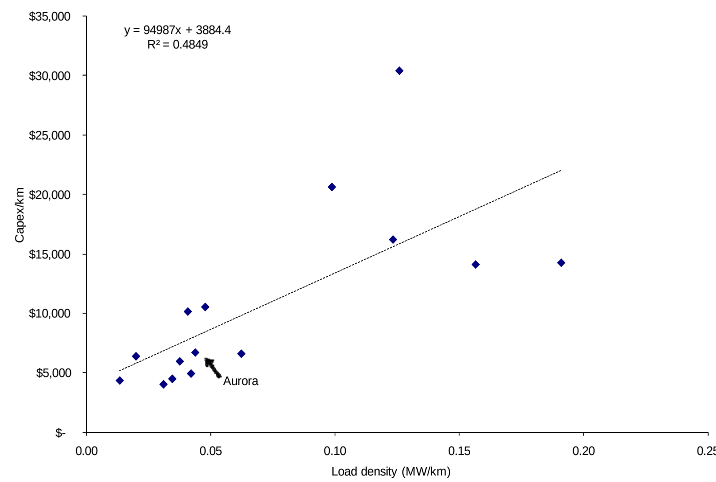
10.2 Capital expenditure

Once again, the purpose of analysing capital expenditure is to assess whether there is any trade-off with operating and maintenance expenditure in Aurora's forecast expenditures. Accordingly, it is presented only as a guide.

10.2.1 Load density and capital expenditure/km

Figure 46 depicting load density and capex/km indicates that load density remains an important explanator of variance in capex/km. However, there is a growing divergence between those DNSPs with older networks and/or high load growth, reflected in the relatively higher rate of capital expenditure.

Figure 46. **Load density and capex/km 2013-15 - $2009**

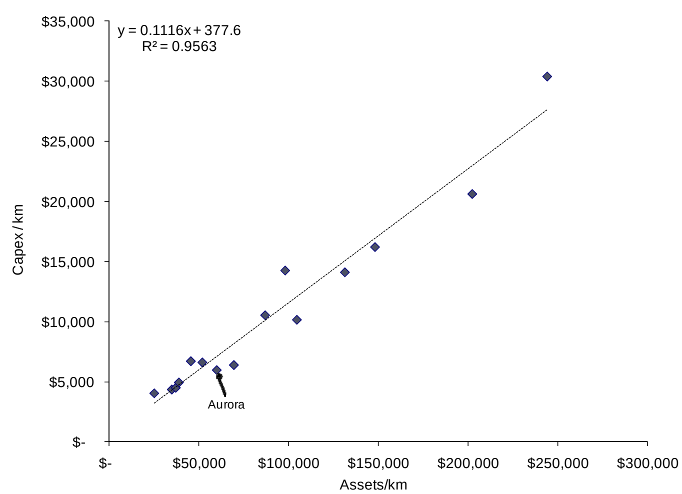


The projected increase in Aurora's submission to the AER for the forecast price set period appear justified by its operating conditions and in line with industry experience. There is nothing to suggest that is offsetting its efficient operating expenditure by a lift in investment.

10.2.2 Assets/km and capex/km

There is a much closer relation between asset values/km and capex/km than between capex and load density (Figure 47).

Figure 47. **Assets/km and capex/km 2013-15 - $2009**



This reflects the fact that expenditure and asset values move in tandem. If load growth is high, expenditure will follow, and reflect in the asset base. Alternatively, if assets are aging, replacement investment will be rolled into the asset base. On the other hand, low levels of expenditure will provide little or no additional input to the asset base. Recall, that a few DNSPs have had their RABs reduced in real terms over the past decade.

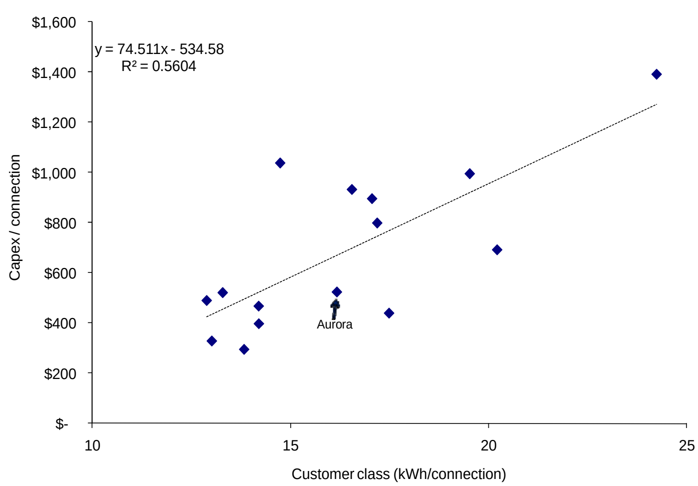
Aurora's proposed level of capital expenditure remains appropriate to the value of its asset base.

10.2.3 Customer class and capex/connection

Finally, Figure 48 depicts the link between capex/connection and customer class. Dispersion around the trend possibly arises from the different approaches to the forecast of future energy consumption at a time of sharply higher prices. A number of the DNSPs predict per capita falls in consumption with a flow-on effect to those performance indicators where energy forms part of the ratio.

Aurora remains below the trend as it has done with all comparison of its capital expenditure performance.

Figure 48.**Load density and capex/km 2013-15 - $2009**



10.2.4 Asset age and capital expenditure

Section 9.2.3 examined the asset age profile for Aurora and its influence on the appropriate level of prudent capital expenditure in 2009. Based on the same analysis it is estimated the probability of failure rate will rise from $28.7M in 2013 and to $35.5 M by 2017, the last year of the price set period.

10.3 2013-15 Efficiency estimates

10.3.1 Estimate of efficient and prudent operating expenditure

Table 15: Efficient Estimates from Equations 5, 6,7- 2013-15 Expenditure

Indicator	Predictor	Estimate	Range	2009 Actual
Opex/km	Load density	$3,388	$3,049-$3,726	$3,371
Total opex		$86.6M	$78.0 - $95M	$86.2M
Opex/km	Assets/km	$3,842	$3,458 - $4,226	$3,371
Total opex		$98.2M	$88.4 - $108.0M	$86.2M
Opex/connection	Customer class	$300	$270 - $330	$296.3
Total opex		$87.4M	$76.7 - $96.0M	$86.2M

The envelope of prudent and efficient operating expenditure for Aurora is derived from the total operating expenditure estimate for these three equations.

Table 16:Efficient operating expenditure envelope: 2013-15			
Load density	Assets/km	Customer class	Efficient cost estimate
$86.6M	$98.2M	$87.4M	Average= $87.3M
		Range +/- 10%	$78.5 - $96.0M

An amount similar to that estimated in the 2009 analysis to take account of the ageing asset base will be required annually for the five year regulatory price period if the older assets are not replaced. That is, an additional amount of around $83M for each year that the older assets are retained in service.

10.3.2 Efficient and prudent capital expenditure

The purpose of analysing capital expenditure is to assess whether there is any proposed trade-off with operating and maintenance expenditure, rather than to provide an estimate of prudent investment. The forecast capital expenditure, as represented by the average of the years 2013-15, is in line with Aurora's business conditions and industry average investment levels. Accordingly, we accept that capital expenditure does not include any off-set for higher/lower operating and maintenance expenditure.

For prudency, it is estimated that the following amounts would be required for refurbishing or replacing aged assets to ensure reliability by reducing the level of potential failure:

Table 17: Estimated capital expenditure due to rising probability of failure 2009 unit costs

2013	2014	2015	2016	2017
$28.7M	$30.4M	$32.2M	$34M	$35.5M

These estimates are based on the assumption that age related expenditure currently is appropriate to the age of the asset base and that no outstanding expenditures are accumulating

Appendix A: Abbreviated terms

DNSPs included in study:

EA Energy Australia

IE Integral Energy

Jemena - Jen

UE United Energy

ENX Energex

CE Aurora

PC PowerCor

SP - AusNet

EGN Ergon

Aurora

ETSA ETSA Utilities

WP Western Power

NSW – aggregate of EnergyAustralia, Integral Energy and Aurora

VIC – aggregate of Jemena, CitiPower, United Energy, SPI-A, and PowerCor

QLD – aggregate of Energex and Ergon

Other abbreviations

AER - Australian Energy Regulator

NER – National Electricity Rules

Capex – Capital expenditure

Operating expenditure – operating and maintenance expenditure

Opex – Operating expenditure

Otter – Office of the Tasmanian Economic Regulator

PDF- Probability distribution function

Total cost – Smoothed regulated aggregate annual revenues

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