Estimated Efficiency Gains from Amalgamation of Electricity Distribution Businesses

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A report commissioned by five electricity generator-retailers and seven electricity distribution businesses

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1. Summary

The purpose of this report is to investigate whether fragmentation of electricity distribution businesses (EDBs) increases costs for electricity consumers and if so whether those costs could be reduced by eliminating barriers to or lack of incentives for EDB amalgamation.

We approach this question by firstly analysing the relationship between EDB size and the aggregate cost associated with operating EDB assets. We then disaggregate the asset operating cost into a capital-intensive component and a labour-intensive component.

Based on the EDBs' aggregate asset operating costs:

- there are apparent savings in asset operating costs from amalgamation (in the order of $123 to $132 p.a. per connection affected);
- however, the apparent gains are found to be explained by differences in customer density; and
- as a result, we find no material gains in aggregate asset operating costs from amalgamation.

Disaggregating EDBs' asset operating costs (AOC) into capital-intensive and labour-intensive components we find that:

- capital-intensive costs are a function of customer density and not size and these costs would not be materially affected by amalgamation; and
- labour-intensive costs (which account for 37% of AOC on average) are a function of customer density and size (to a lesser degree) so there may be potential reductions in these costs (in the order of $30 to $31 p.a. per affected connection) from amalgamation.

Overall, we conclude that there may be some small potential gains from amalgamation of EDBs. These gains could include reduced management and procurement costs and improved strategic capability. However, it should be noted that the gains may be achievable through contracting arrangements like sharing of services, strategic alliances or joint ventures, which don't require amalgamation.

It should be noted that no allowance has been made in our estimates for the transaction and implementation cost of amalgamation.

2. Introduction

2.1 Background

The Energy Companies Act, 1992 required all existing electricity supply authorities (ESAs)[1] to incorporate as companies under the Companies Act 1993. The Act required local consultation and polls of consumers and ratepayers about share ownership plans that were incorporated in the establishment plans to be approved by the Minister of Energy. At the same time, the statutory monopoly previously enjoyed by ESAs along with the obligation to supply were removed by the Electricity Act, 1992.

The pattern of ownership of EDBs that resulted was broadly as follows:

- 21 of 44 energy companies elected to be wholly owned by community or consumer trusts;
- ten elected partial trust-ownership;
- one was a co-operative company;
- nine were owned by local councils; and
- three were investor-owned (see New Zealand Electricity Directory 1993).

The impetus for reform of the electricity sector grew out of the concerns about the overall economic performance of the New Zealand economy that became widespread in the 1980s. The ESAs were a natural target for inclusion among wide-ranging micro-economic reforms aimed at achieving faster economic growth through more efficient resource use, stimulated by clearer price signals and, where possible, by competitive markets. The case for ESA reforms was based on the lack of customer choice, cross subsidisation and drivers more for commercial decisions. Incorporation under the Companies Act brought into play commercial governance of day-to-day management decisions, even if ownership arrangements reflected community political considerations.

[1] These ESAs included 38 special purpose local authorities operating under the Electric Power Board Act 1925 (EPBs), 21 municipal electricity departments of territorial local authorities (MEDs), and two government owned authorities (Southland Electric Power Supply and Chatham Islands Electricity System).

The past quarter century has seen several acquisitions and mergers among EDBs such that the number of EDBs has reduced to 29 (effectively 26 when joint management arrangements are consolidated[2]). While the day-to-day management of these entities is under the governance of directors whose roles are commercial, the consolidation that has occurred has not much affected the dominant pattern of ultimate control of the EDBs by elected trustees and territorial authorities governed by elected councillors. If the architects of the 1990s electricity reforms thought there would be a progressive amalgamation of EDB businesses to reap further efficiencies, then the reforms have been a disappointment. 12 of the current EDBs serve fewer than 25,000 customer connections while only four EDBs serve 100,000 or more. Only three of the four largest EDBs are directly exposed to equity capital market disciplines through either share market listing or private ownership.

Thus, there remains an enduring suspicion in some quarters that electricity distribution has for the most part not evolved, and that the trust or local governance ownership arrangements affecting the large majority of EDBs may be inhibiting efficient rationalisation in the sector. The consequences would be that electricity consumers face higher-than-necessary costs that are reflected in the charges they pay for electricity. This suspicion is reinforced by comparisons with Australia where twelve EDBs serve 9 million customer connections, in contrast with New Zealand where 26 (effective) EDBs serve 2 million customer connections.

Despite considerable information relating to EDB efficiency being available from the Commerce Commission database of statutory disclosures, little empirical analysis appears to have been done to test whether the electricity distribution sector has varying levels of efficiency that might be explained by entity size, and hence might be reduced by fostering amalgamation.

TDB Advisory was engaged to estimate the potential efficiency gains from EDB amalgamation based on the data EDBs are required to provide the Commerce Commission. The analysis was undertaken at a relatively high level to provide an indication of the range of potential gains available. This report provides a summary of the analysis undertaken and our findings.

[2] Unison+ is consolidated to include Unison and Centralines, and, Powernet is consolidated to include The Power Company, OtagoNet and Electricity Invercargill.

2.2 Purpose of the report

This report presents an analysis of how the efficiency of EDBs is affected by their size.

The report addresses the question: *Does fragmentation of EDBs increase cost for some electricity consumers where those costs could be reduced by eliminating barriers to EDB amalgamation?*

This report:

- uses data sourced from the EDBs' statutory disclosures as published by the Commerce Commission;
- uses the Australian Energy Regulator's (AER) definitions of input and output measures which the AER uses to benchmark the productivity of electricity distribution network service providers in that country;
- considers only potential amalgamation gains from asset efficiency improvements related to size;
- does not consider other potential sources of scale efficiencies such as overhead spreading, procurement, marketing, or risk management;
- does not consider other sources of efficiency improvement that are unrelated to size;
- does not consider the transaction and restructuring costs of any amalgamations; and
- does not consider any potential gains to other parties in the electricity system from amalgamation of EDBs (such as the gains from generator-retailers from having fewer parties to transact with).

2.3 Structure of the report

The report is organised as follows; Section 4 sets out the conceptual framework for the existence of internal economies of scale that provide cost savings when firms amalgamate. This section describes the approach to estimating industry cost curves related to firm size. The next section, Section 5, presents estimates of the statistical relationships between average asset operating cost and size derived from statutory disclosure data.

Section 6 provides estimates of the apparent efficiency gains from EDB amalgamations based on the analysis of asset operating costs. Two hypothetical amalgamation scenarios have been used to test the possible size of gains in asset operating costs.

Section 7 presents a modified analysis where costs are disaggregated in to capital-intensive (63 per cent of industry average costs) and labour-intensive components (37 per cent of industry average costs). Section 8 presents our conclusions.

3. Methodology

3.1 Framework for the analysis

In microeconomics an "economy of scale" is a cost advantage that firms obtain due to their size. Size is typically represented by the volume of output produced. When average (per unit) costs fall as output increases, economies of scale are said to occur. Seeking an economy of scale has long been the underpinning theory for much business behaviour from mass production to mergers and acquisitions.

An industry that exhibits economies of scale is one where the costs of production fall when the number of firms in the industry drops, but the remaining firms increase their production to match previous levels.

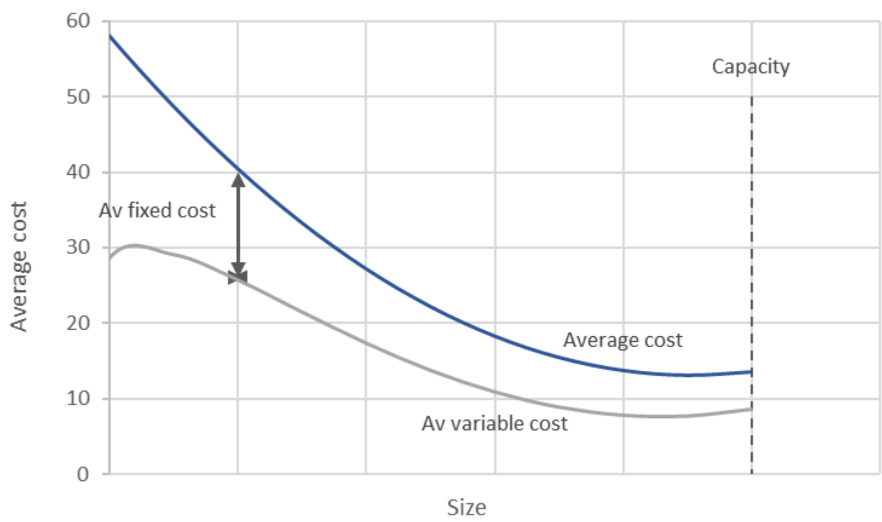
These ideas, derived from the field of managerial economics, are intuitive: if delivery of a service entails an element of fixed costs (that does not vary with service level) then the average costs of the service will decline with increases in provision until the limit of capacity is reached.

This relationship between service level and average cost of provision is illustrated in Figure 1. What may be overlooked is the important qualification that once capacity is reached average costs stop falling. To meet still further levels of service delivery additional increments of fixed cost is required. The savings from spreading fixed costs over more production only applies until capacity is reached.

Our approach is also related to the notion of the structural efficiency of an industry.

Structural efficiency is the extent to which an industry keeps up with the performance of its own best firms and it can be measured by comparing the horizontal aggregation of the industry's firms with the frontier constructed from its individual firms. This is similar to the way we measure the aggregate gain from a merger.

Figure 1: Illustration of declining average costs

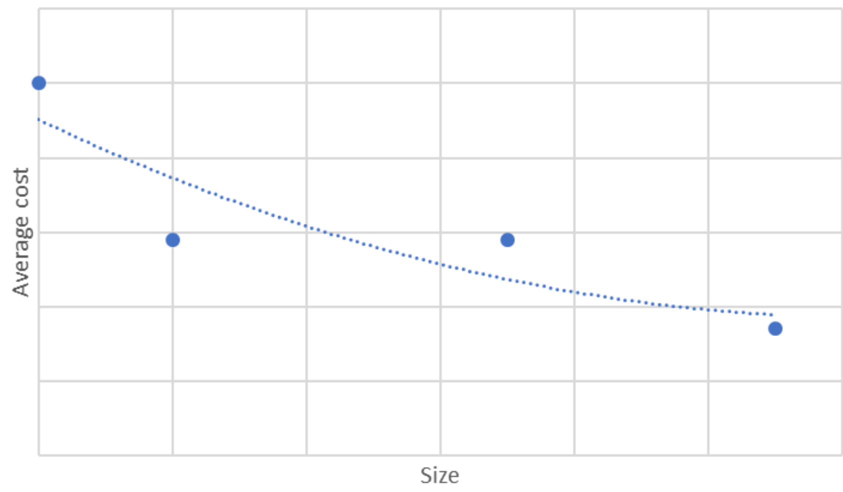


Economies of scale can also have a "dark" side called "diseconomies of scale". The larger an organisation becomes, the more complex it has to be to manage and run itself. This complexity incurs a material cost, and eventually this cost may come to outweigh the savings gained from greater size. In other words, an economy of scale does not necessarily apply forever. There is a qualitative difference that is also important: savings from combining service delivery tend to be identifiable and measurable at an operational level, while the diseconomies from size tend to creep up insidiously in the shape of policies, procedures, rigid organisational culture and additional management layers.

Industries tend to exhibit similar long-run supply cost behaviour: either constant-cost, increasing-cost or decreasing cost. Cost structures have direct implications for the number and size of firms within the industry (industrial structure).

- Increasing cost industries tend to be fragmented. A fragmented industry is one that has no major participants (or brands) and the individual firms tend to be small. Business practices may vary widely because individual owners use differentiated methods.
- Decreasing cost industries tend to be concentrated. In concentrated industries the four largest firms tend to account for over 80 percent of the industry's output.
- Constant cost industries have mixtures of small and large firms.

Figure 2: Illustration of a declining industry cost curve



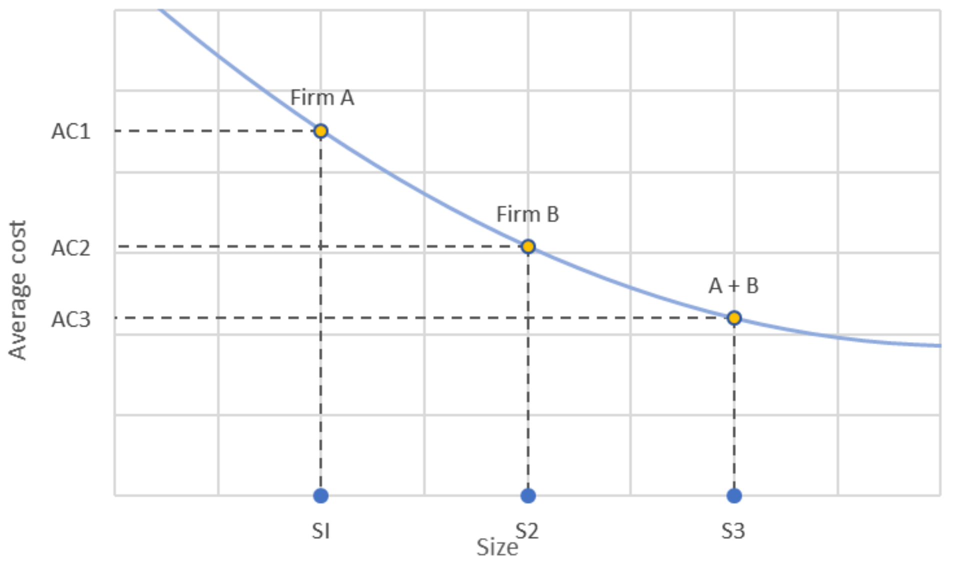
In decreasing cost industries, the industry supply curve is downward sloping. If firms within the industry can become larger by taking market share from rivals or through horizontal amalgamations, they gain efficiency and competitiveness. Concentration can also be a natural result of some firms satisfying their customers more than their rivals, supporting the view that competing successfully causes concentration. A downward-sloping supply curve also arises when expansion itself lowers input prices or when firms can use scale economies to produce at lower cost. Amalgamation gains arise only from movements along the industry cost curve, not from movements toward the curve, which do not depend on size for achievement.

3.2 Method for quantifying gains from amalgamation

Figure 3 shows how the potential gains from amalgamating smaller firms can be estimated from a declining industry cost curve. Firm A produces S1 at an average cost of AC1. Firm B, produces twice as a much as Firm A (S2) at a lower average cost AC2. If the two firms are combined, their total production of S3 = S1 + S2 can be produced at a lower average cost (AC3) than that of either Firm A or Firm B.

The resulting cost savings can be calculated by adding the excess costs of production of Firm A ((AC1 – AC3) x S1) and of Firm B ((AC2 – AC3) x S2). Under competitive conditions, the customers of the new amalgamated firm would gain from the costs savings achieved by amalgamation.

Figure 3: Illustration of amalgamation gains



- *The combination of Firm A and Firm B lowers the average cost (AC1 and AC2) of serving their combined customers (S3 = S1 + S2) to AC3.*
- *Amalgamation gain is (AC1 x S1 plus AC2 x S2) less (AC3 x S3).*

3.3 Information disclosure data

Part 4 of the Commerce Act, 1986 (as amended) provides a regulatory regime for EDBs and sets out the requirements for information disclosure. The purpose of the information disclosure regulations is to ensure that information is available to enable assessment of whether industry performance is consistent with a competitive market.

Information disclosed by electricity distributors from 2013 to 2017 is available on the Commerce Commission's website. A longer series of data (from 2003 to 2017) is also available on a more aggregated basis.

3.4 Measures of size

Using the information disclosure data, three measures of EDB size were compiled, as follows:

- energy delivered (GWh);
- maximum demand (MW); and
- customer connections (No. of ICPs).

3.5 Measures of efficiency and cost

Measures of the structural efficiency of the EDBs were compiled from the information disclosures using the AER methodology for estimating average asset operating costs. Average asset operating costs for each EDB were calculated as the sum of:

- a return on capital employed, estimated as the pre-tax weighted average cost of capital (WACC) for regulatory capital employed;
- depreciation; and
- asset operating costs (allocated pro-rata to operating asset classes by value where necessary).

4. Statistical relationships between asset operating cost and firm size

In this section estimates of the potential amalgamation gains are derived using the methodology described in Section 4.2.

Figure 4 shows a chart of asset operating cost (AOC) per customer connection and EDB size measured by customer connections for 2003-2017. Each data point represents one observation for one EDB.

It may be observed that there is a broad spread of average asset operating costs among the smaller EDBs (measured by customer connections), but a tighter relationship as EDB size increases.

Figure 4 is broadly indicative of an industry where there is some negative relationship between average costs and size (i.e. there appears to be economies of scale in the industry). Moreover, this cross-sectional relationship looks to have been fairly stable over time.

The other observation is that at around 100,000 customer connections the downward slope of the curve has weaker relationship with respect to size (measured by customer connections). However, the wide spread of average costs provides a hint that there may be other important cost drivers to consider as well as size.

Figure 4: Average asset operating costs and customer connections (2003-2017)

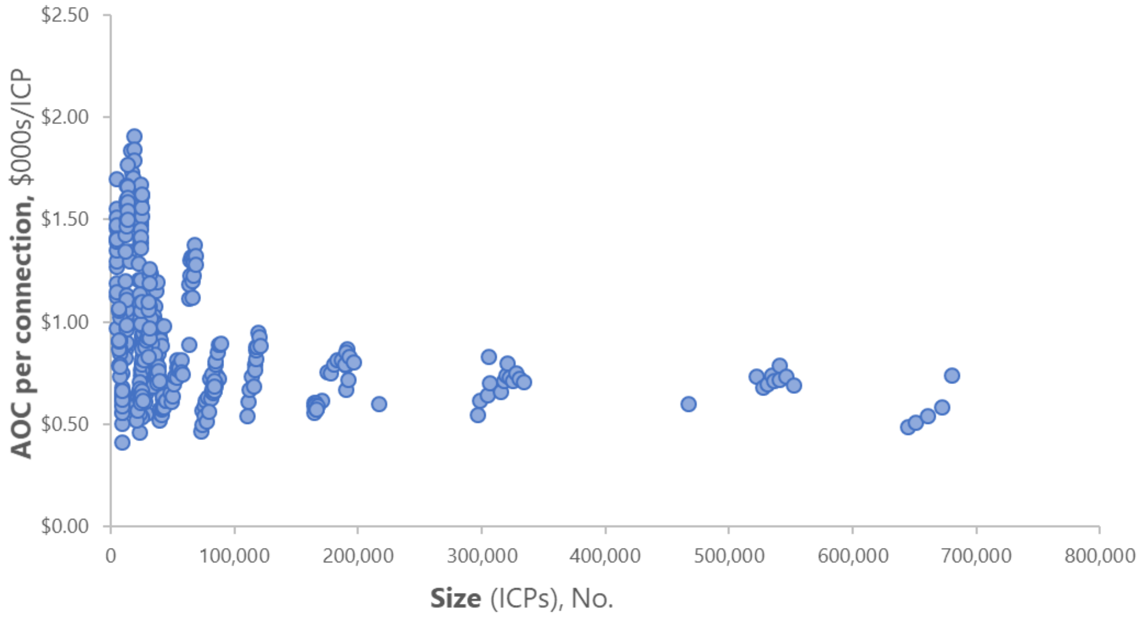


Figure 5 looks at the same relationship between customer connections and asset operating cost as Figure 4, but for the most recent five disclosure years (2013-2017). This data-series exhibits the same general relationship of economies of scale seen in the longer data-series above.

The disclosure data also provides two additional output measures that we consider measures of EDB size: total energy delivered (GWh) and maximum demand (MW). Figures 6 and 7 present asset operating cost per the different size measures, and the relationships remain very similar as for customer connections. There is some association of asset operating costs with EDB size regardless of which size measure is employed. From the diagrams we observe:

- the apparent industry cost curve is downward sloping at low size levels (i.e., decreasing cost), but with a fair amount of "noise"; and
- the apparent industry cost curve is broadly flat at higher size levels, i.e., fairly constant cost (above about 100,000 customer connections, 2,000 GWH or 400 MW).

Figure 5: Average asset operating costs and customer connections (2013-2017)

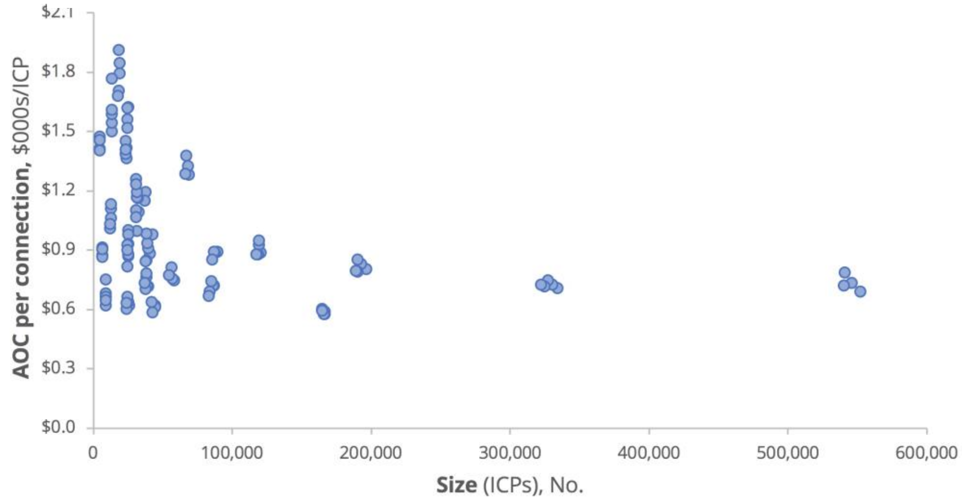


Figure 6: Average asset operating costs and energy delivered (2013-2017)

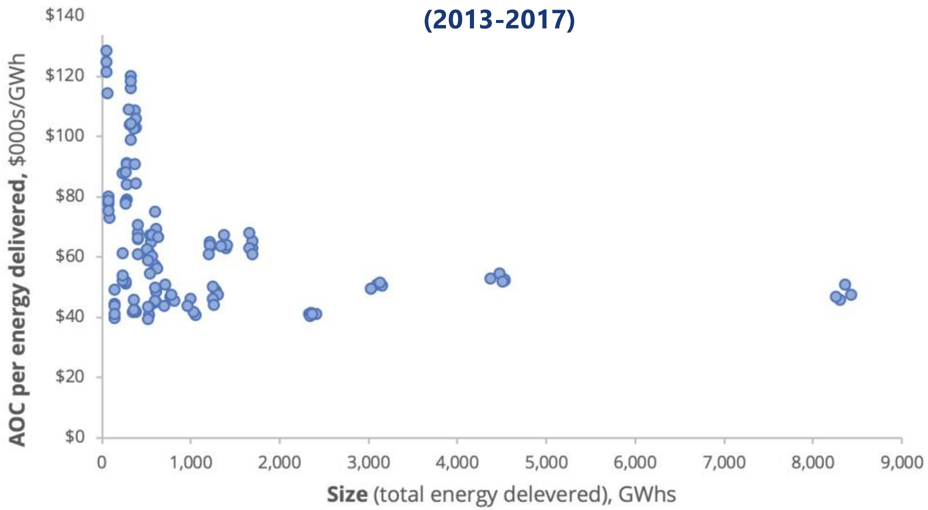
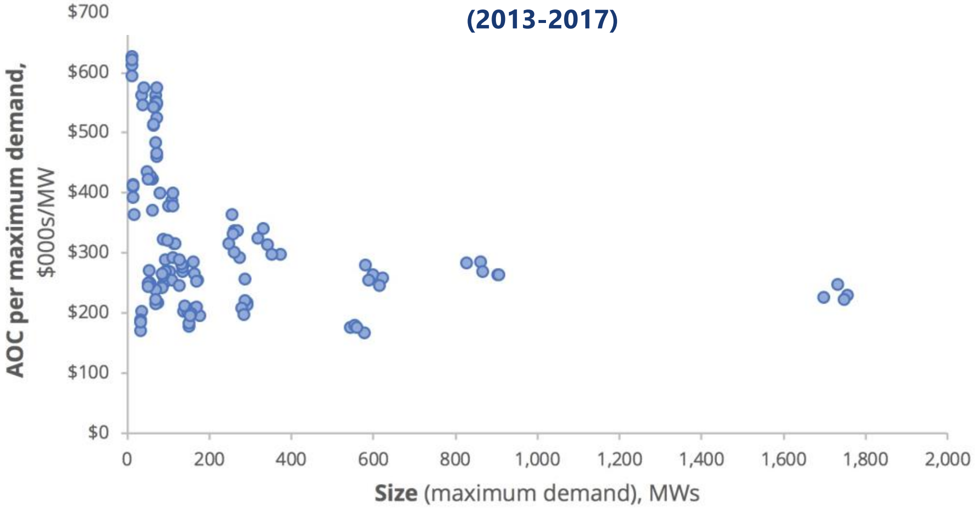


Figure 7: Average asset operating costs and maximum demand (2013-2017)



4.1 Estimating the statistical relationships between average asset operating cost and size

To better understand the relationship between average asset operating costs and EDB size, a model of the association was developed. The general form of the model is:

$$\ln\left(\frac{Av\ Op\ Cost}{Size}\right) = \alpha + \beta \ln(Size) + \varepsilon, \qquad (1)$$

where ln() is the natural logarithm, α and β(size) are parameters to be estimated, ε is an error term, and "Av Op Cost" and "Size" are inputs from the information disclosure data.

If a statistical association exists between EDB size and average asset operating costs, the parameter β will have a negative sign and be statistically significant. Statistical significance is a measure of the likelihood that a relationship between two variables is caused by something other than chance.

Table 1 shows the estimates of the parameters α and β, alongside the statistical significance of the estimates upon our three different measure of size. The β parameter estimates have the expected negative signs and are significant at the 1 percent level (indicating only a 1 percent chance that the association is by chance).

Table 1 demonstrates statistical evidence of an increase in EDB size being systematically associated with declining average asset operating costs. However, the explanatory power of the model (represented by R^2) is low. The R^2 statistics are saying the size model only accounts for between one-fifth and one quarter of the observed variation in asset operating cost. We may use the models to predict size-related costs while acknowledging that 75 to 80 percent of asset operating costs is influenced by something other than size.

Table 1: Average asset operating cost and size

Dep. variable: Ln(asset operating cost/size)

	Size measure		
	Total energy delivered	Maximum demand	Customer connections
	(1)	(2)	(3)
Intercept (α)	5.00***	6.44***	1.28***
	[0.15]	[0.12]	[0.25]
Ln(size) (β)	-0.14***	-0.15***	-0.13***
	[0.02]	[0.02]	[0.02]
R^2	0.24	0.24	0.20
Obs.	121	121	121

Note: The results presented by the table are from ordinary least squares (OLS) regressions. Each column presents a regression conducted with a different measure of firm size (defined in the table). The dependent variable is the Ln of asset operating cost, calculated as return on capital plus deprecation plus opex. The independent variable data comes from NZ Commerce Commission disclosures. Standard errors are reported in square brackets. *,**,*** indicates significance at the 10%, 5% and 1% levels.

Figures 8, 9 and 10 show the apparent industry cost curves based on energy delivered, maximum demand and customer connections respectively. The apparent industry cost curves are downward sloping suggesting cost savings from amalgamating smaller firms could be expected.

Using the approach demonstrated in Figure 3 above, a level of cost savings associated with a particular combination of EDBs may be estimated.

This approach to estimating the apparent efficiency gains from EDB amalgamation is discussed in the following section.

Figure 8: Estimated industry costs curve, customer connections

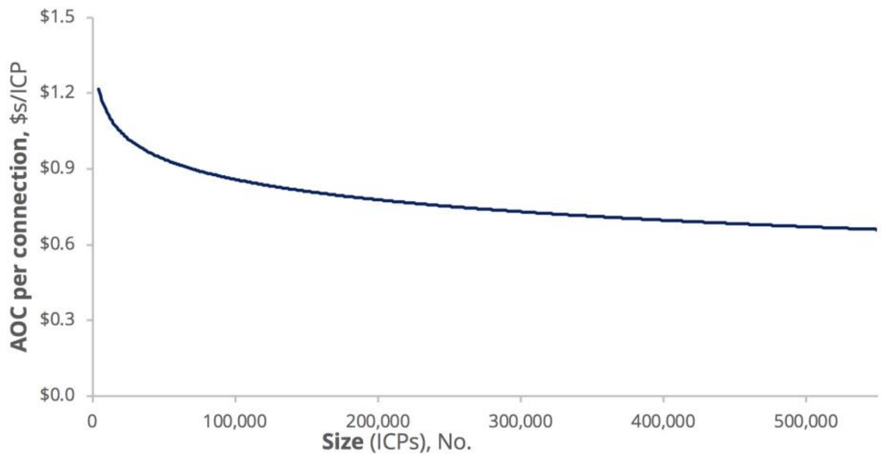


Figure 10: Estimated industry cost curve, energy delivered

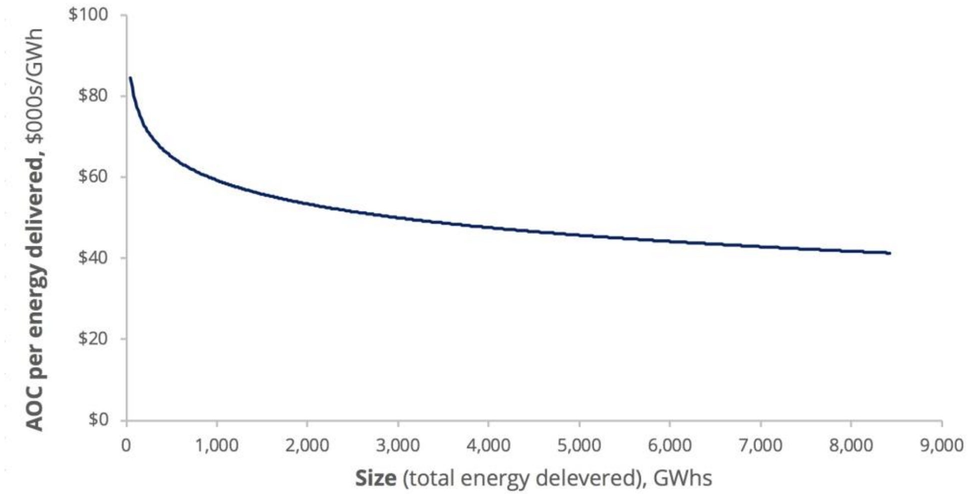
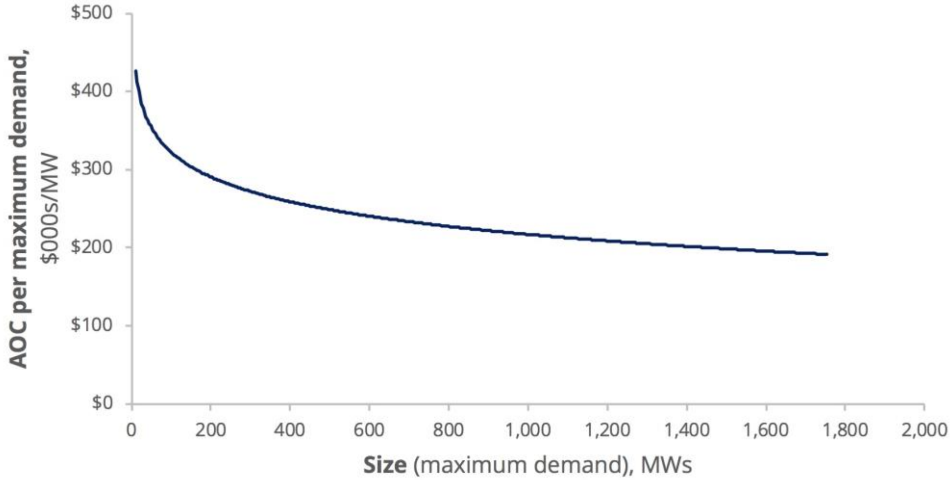


Figure 9: Estimated industry costs curve, maximum demand



5. Apparent efficiency gains from EDB amalgamation

5.1 Estimating apparent efficiency gains from amalgamation

Two amalgamation scenarios have been used to test the possible size of the gains from EDB amalgamation. The scenarios are hypothetical. The EDBs have deliberately been anonymised. Selection of candidates for amalgamation was made purely on the basis that the resulting amalgamated entity would have no fewer than 50,000 customer connections (Scenario 1) or 100,000 customer connections (Scenario 2). In Scenario 1, the 29EDBs are consolidated into 15, while in Scenario 2 there are 11 EDBs. Customer connections has been used as the basis for selecting combinations for ease of understanding, although we present estimates for all three size measures. The point of having two size-related scenarios is to test the sensitivity of the results around the point where the industry cost curve flattens out.

Table 2: Apparent efficiency gain estimates from EDB amalgamation

	Scenario 1	Scenario 2
Customer connections served by smallest EDB	50,000	100,000
Resulting number of EDBs	15	11
Affected customers	410,000	707,000
Estimated apparent efficiency gains, based on		
energy delivered, $m p.a.	50	94
maximum demand, $m p.a.	56	103
customer connections, $m p.a.	46	83
Average gain per affected customer, $ p.a.	123	132

As shown in Table 2, the apparent efficiency gains under Scenario 1 range from $46 million p.a. to $56 million p.a. with a mean value equivalent to $123 p.a. per customer connection affected. To be clear, the apparent gains are only available to the customers of the amalgamating entities, not all electricity customers.

Under Scenario 2 the apparent gains range from $83 million p.a. to $103 million p.a. or $132 p.a. per customer connection affected on average.

These estimates however are before allowing for the effect of customer density which, as discussed in the following section, has a major effect on the results.

5.2 Customer density

Variation in customer density is a matter raised as a possible explanation for variation in costs between EDBs. Amalgamation of EDBs would not of itself alter the customer density of the amalgamated entity relative to the antecedents. In this context, density is measured by the ratio of size to length of circuit:

- customer connections per km of circuit, (NoC/CL);
- total energy delivered per km of circuit, (TED/CL); and
- maximum demand per km of circuit, (MD/CL).

As may be seen in Figures 11, 12 and 13, asset operating costs vary with customer density in a similar way that size does. This conclusion holds regardless of the three density measures used.

Figure 11: Average asset operating costs & customer connection density

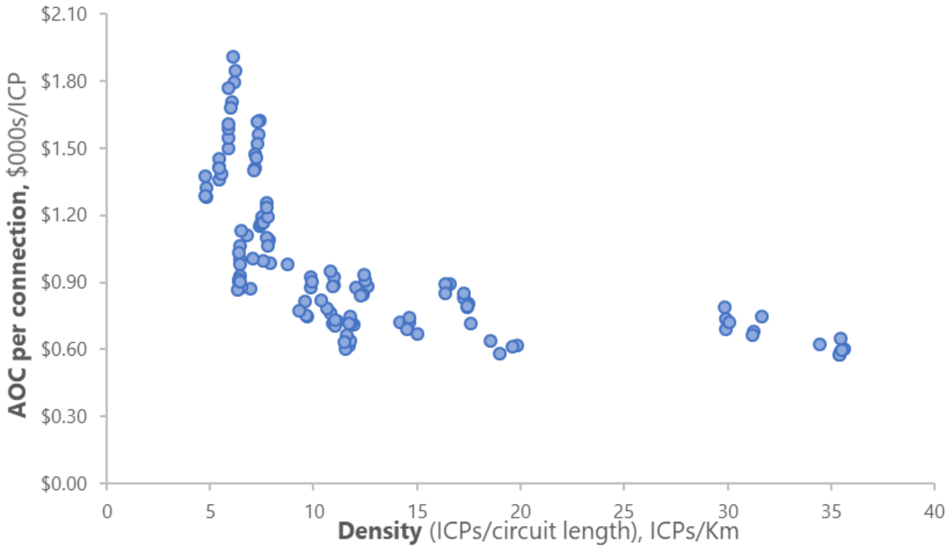
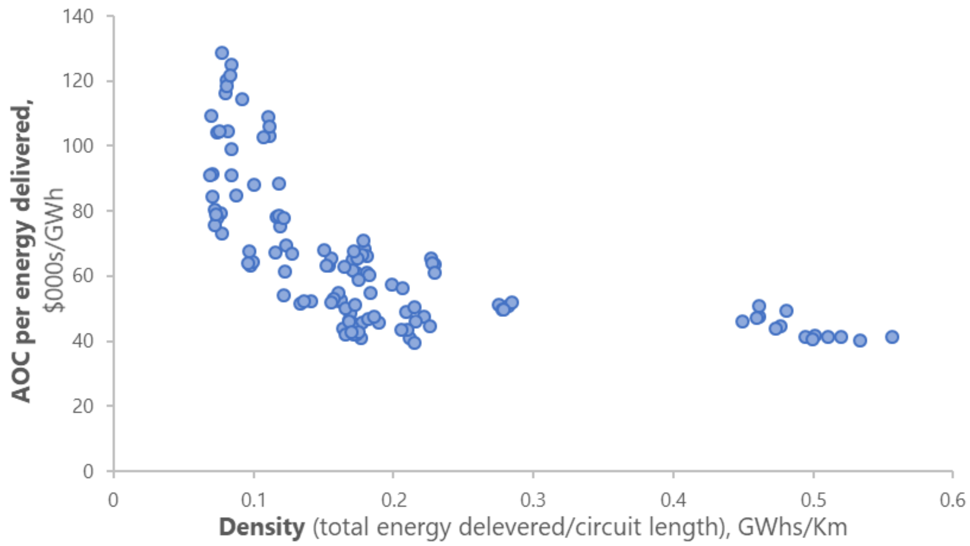


Figure 112: Average asset operating costs & energy delivered density

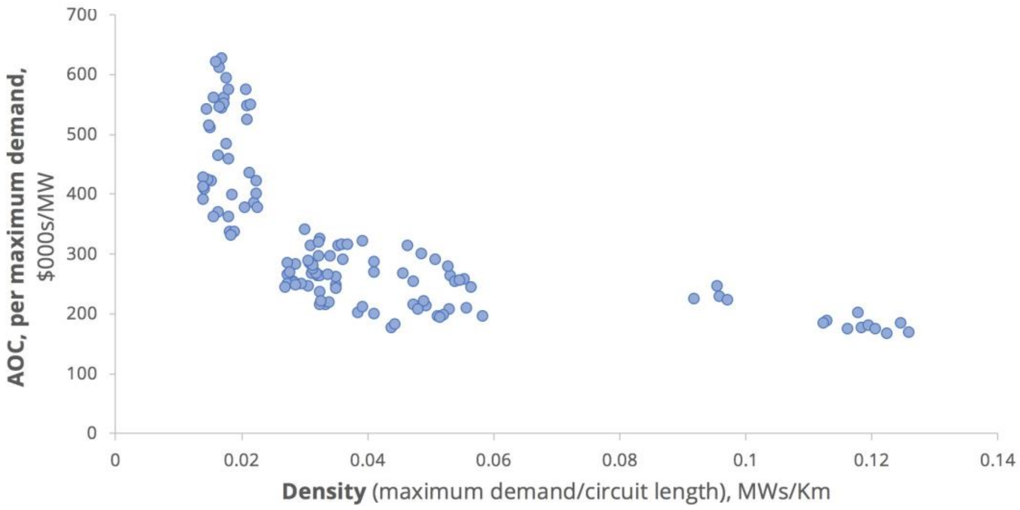


From the appearances in Figures 11, 12 and 13:

- the apparent cost curve is downward sloping at low size levels, i.e., decreasing cost;
- the apparent cost curve is broadly flat at higher size levels when customer connections is the size measure; and
- the apparent cost curve declines but less steeply at higher density levels for energy delivered and maximum demand size measures.

Density therefore appears to be a factor that also has a decreasing relationship with aggregate asset operating cost.

Figure 12: Average asset operating costs & maximum demand density



To better understand how density affects the relationship between asset operating costs and EDB size, the model was revised to include density. The general form of the model is:

$$\ln\left(\frac{Av\ Op\ Cost}{Size}\right) = \alpha + \beta_1 \ln\left(\frac{Size}{Cir\ Length}\right) + \beta_2 \ln(Size) + \varepsilon, \qquad (2)$$

where ln() is the natural logarithm, α, β_1(density) and β_2(size) are parameters to be estimated, ε is an error term, and "Av Op Cost", "Cir Length" and "Size" are inputs from the information disclosure data.

If a statistical relationship exists between EDB size and density and average asset operating costs, then the parameters β_1 and β_2 respectively will have a negative sign and be statistically significant. Table 3 shows the estimates of the coefficients for the intercept, β_1 and β_2 and presents the statistical significance of the estimates.

Table 3 demonstrates statistical evidence of an increase in customer density systematically associated with declining average operating costs as a stronger relationship than EDB size. On two of the three size measures (energy delivered and customer connections), it cannot be said confidently that the size relationship is any more than a random association. Moreover, introducing customer density improves the power of the model to explain the drivers of EDB cost from between 20 percent and 25 percent to between 60 percent and 70 percent.

Thus we may confidently conclude that when deriving an industry cost curve it is important to take account of how customer density impacts on asset operating costs. When this is done the relationship between EDB size and asset operating costs become statistically insignificant, or barely significant. The logical conclusion is that size alone is not the issue driving asset operating costs. In fact, the apparent gains in asset operating costs from amalgamation are overwhelmingly explainable by differences between EDBs in customer density.

Since density matters much more than size *per se* in predicting EDBs' asset operating costs, and density would be unaffected by amalgamation of EDBs (it is an external factor), we can be confident in dismissing size as a relevant factor.

Table 3: Asset operating cost, size and density relationship

Dep. variable: Ln(asset operating cost/size)

	Size measure		
	Total energy delivered	Maximum demand	Customer connections
	(1)	(2)	(3)
Intercept (α)	3.59***	4.21***	1.18***
	[0.17]	[0.19]	[0.17]
Ln(density) (β_1)	-0.41***	-0.47***	-0.43***
	[0.04]	[0.04]	[0.04]
Ln(size) (β_2)	-0.03*	-0.02	-0.02
	[0.02]	[0.02]	[0.02]
Adj. R^2	0.59	0.68	0.60
Obs.	121	121	121

Note: The results presented by the table are from OLS regressions. Each column presents a regression conducted with a different measure of firm size (defined in the table). The dependent variable is the Ln of asset operating cost, calculated as return on capital plus deprecation plus opex. The independent variable Density is defined as size/circuit length for each firm in a given firm-year. Data comes from NZ Commerce Commission disclosures. Standard errors are reported in square brackets. *,**,*** indicates significance at the 10%, 5% and 1% levels.

Re-working Scenarios 1 and 2 using the density-adjusted industry cost curve eliminates the apparent gains from amalgamation under both Scenario 1 and 2.

Before concluding the analysis, we examine in the next section the cost drivers of sub-components of asset operating costs to see if density and size operate differently at a disaggregated level.

6. Disaggregated asset operating costs

This section addresses whether there could be differences in the size and density relationships within sub-components of asset operating costs. In economics, factors of production are resources which are used to produce outputs. There are three basic resources or factors of production: land, labour and physical (or fixed[3]) capital. Land is not a major consideration in the cost of production of electricity distribution services. It is possible to decompose asset operating costs into a component (around 60 percent on average) which has physical capital as a driver, and a component which has labour costs as a driver. We refer to these cost components as the capital-intensive and labour-intensive components.

6.1 Modelling capital-intensive and labour-intensive costs

For this part of the analysis the same model was used as the one used to estimate the relationship between asset operating costs and EDB size and density. The model was estimated for two data sets:

- **capital-intensive costs** represented by depreciation and return on capital which make up 64.3 percent of industry average operating costs; and
- **labour-intensive costs** including operations and maintenance costs which make up 37 percent of industry average operating costs.

Table 4 shows the resulting sub-component model for the labour-intensive costs. Table 4 shows that labour-intensive costs exhibit a negative and significant relationship with both the density and size variables. However, the size parameter is relatively small. Thus, there is a small size-related influence on the component of costs relating to labour-intensive activities.

Table 4: Labour-intensive cost component

Dep. variable: Ln(opex/size)

	Size measure		
	Total energy delivered	Maximum demand	Customer connections
	(1)	(2)	(3)
Intercept (α)	2.91***	3.39***	0.8***
	[0.21]	[0.23]	[0.19]
Ln(density) (β_1)	-0.43***	-0.49***	-0.42***
	[0.05]	[0.04]	[0.04]
Ln(size) (β_2)	-0.1***	-0.09***	-0.09***
	[0.02]	[0.02]	[0.02]
Adj. R^2	0.61	0.67	0.62
Obs.	130	130	130

Note: The results presented by the table are from OLS regressions. Each column presents a regression conducted with a different measure of firm size (defined in the table). The dependent variable is Ln of the reported opex/size. The independent variable Density is defined as size/circuit length for each firm in a given firm-year. Data comes from NZ Commerce Commission disclosures. Standard errors are reported in square brackets. *,**,*** indicates significance at the 10%, 5% and 1% levels.

[3] Fixed capital is the expression used in the New Zealand System of National Accounts for plant and equipment as distinct from financial capital.

Table 5: Capital-intensive cost component

Dep. variable: Ln(capital cost/size)

	Size measure		
	Total energy delivered	Maximum demand	Customer connections
	(1)	(2)	(3)
Intercept (α)	2.99***	3.68***	0.42***
	[0.18]	[0.19]	[0.19]
Ln(density) (β_1)	-0.4***	-0.46***	-0.43***
	[0.04]	[0.04]	[0.04]
Ln(size) (β_2)	0.00	0.01	0.01
	[0.02]	[0.02]	[0.02]
Adj. R^2	0.51	0.63	0.52
Obs.	121	121	121

Note: The results presented by the table are from OLS regressions. Each column presents a regression conducted with a different measure of firm size (defined in the table). The dependent variable is calculated as the Ln of a return on capital plus deprecation/size. The independent variable Density is defined as size/circuit length for each firm in a given firm-year. Data comes from NZ Commerce Commission disclosures. Standard errors are reported in square brackets. *,**,*** indicates significance at the 10%, 5% and 1% levels

Table 5 depicts the results for the estimation of the relationship between the capital-intensive costs and the different measures of size.

As shown in Table 5, for the capital-intensive cost model the density coefficient is, as expected, negative and is statistically significant at the 1 percent level. The size parameter has the expected sign but is much smaller and is not statistically significant.

We finally note that both sub-models are explaining roughly the same amount of variation in their respective costs component (51 percent to 63 percent for capital-intensive costs and 61 percent to 67 percent for labour-intensive costs).

6.2 Estimated efficiency gains using disaggregated cost model

Table 6 shows the estimated efficiency gains using the disaggregated cost model. In all instances in the calculations we estimate the gains by setting the coefficient relating to density to zero and where statistically significant the coefficient relating to size to its estimated value.

Using a disaggregated model of EDB costs:

- the estimated efficiency gain from amalgamating under EDBs with fewer than 50,000 customer connections is in the range from $2 million p.a. to $29 million p.a. with a mean value equivalent to $30 p.a. per affected customer connection; and
- The apparent gains range from $3 million p.a. to $55 million p.a. or $31 p.a. per affected customer connection on average if the smallest EDB is 100,000 customer connections.

Table 6: Estimated efficiency gain from EDB amalgamation

	Scenario 1	Scenario 2
Estimated apparent efficiency gains, based on		
energy throughput, $m p.a.		
capital-intensive costs	$0	$0
labour-intensive costs	$6	$8
total	**$6**	**$8**
maximum demand, $m p.a.		
capital-intensive costs	$0	$0
labour-intensive costs	$2	$3
total	**$2**	**$3**
customer connections, $m p.a.		
capital-intensive costs	$0	$0
labour-intensive costs	$29	$55
total	**$29**	**$55**
Average gain, $m p.a.	**$12**	**$22**
Average gain per affected customer, $ p.a.	**$30**	**$31**

7. Conclusions

The data sourced from the EDBs' statutory disclosures provides the basis for making a robust assessment of the impact of size and customer density on the efficiency of the EDBs and thus the potential gains from amalgamating the EDBs. We find, when considering only the impacts of size but not adjusting for density:

- the apparent efficiency gains from amalgamating EDBs with fewer than 50,000 customer connections is in the range of $46 million p.a. to $56 million p.a. with a mean value equivalent to $123 p.a. per affected customer connection; and
- the apparent gains range from $83 million p.a. to $103 million p.a. or $132 p.a. per affected customer connection on average if the smallest EDB is 100,000 customer connections.

However, when customer density is taken into account, the apparent amalgamation gains disappear. Customer density has a bigger impact on predicting asset operating cost than does size and the impact of size (once density is allowed for) is not statistically different from zero.

When asset operating costs are disaggregated into capital-intensive and labour-intensive activities it is apparent that customer density remains the most important influence on EDB cost, although size has a small negative influence on labour-intensive costs.

Using a disaggregated model of EDB costs:

- the estimated efficiency gain from amalgamating EDBs with fewer than 50,000 customer connections is in the range of $2 million p.a. to $29 million p.a. with a mean value equivalent to $30 p.a. per affected customer connection; and
- the apparent gains range from $3 million p.a. to $55 million p.a. or $31 p.a. per affected customer connection on average if the smallest EDB has 100,000 customer connections.

Overall, we find the potential gains from EDB amalgamation are relatively small. Our estimates do not include any allowance for the transaction and integration costs associated with amalgamation.

In addition, we find that around two-thirds of the systematic variation of costs between EDBs can be explained by density and size. However there remains another one-third which cannot be explained by these factors. Further work by the Commerce Commission to understand the reason for these cost differences is recommended.

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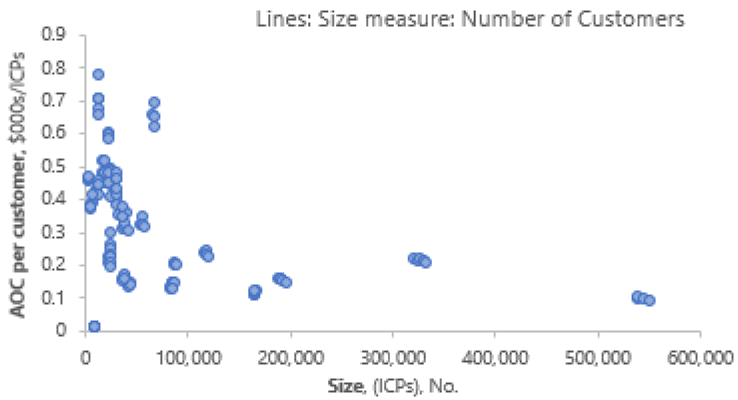
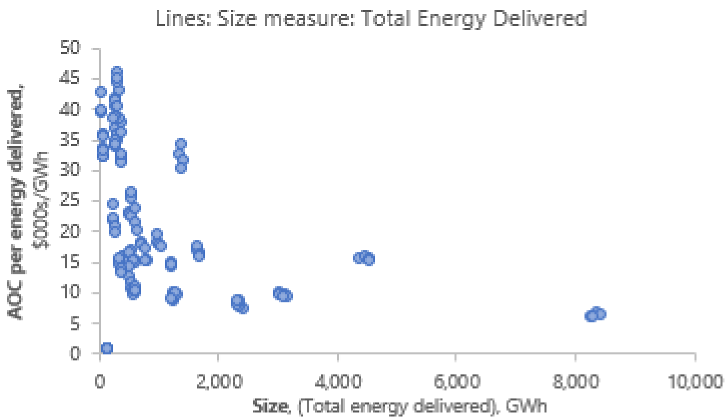
Appendix A: Disclosure information

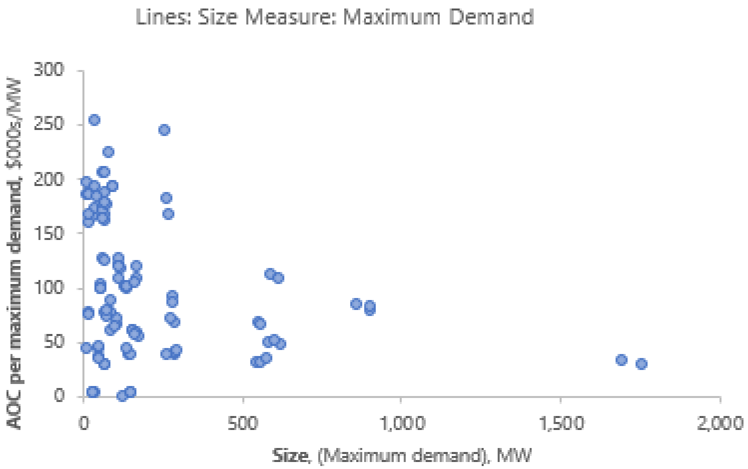
EDB	Number of Customers (ICPs)	Circuit Length (km)	Total Energy Delivered (GWh)	Maximum Demand (MW)	Density (Customers/ Circuit Length)	Return on Capital ($000)	Depreciation ($000)	Operating Expenditure ($000)	Asset Operating Cost ($000)
Alpine Energy	33,000	4,200	760	130	7.8	$11,000	$10,000	$15,000	$36,000
Aurora Energy	87,000	6,100	1,300	290	14	$23,000	$13,000	$27,000	$63,000
Buller Electricity	4,600	640	50	10	7.1	$1,900	$1,400	$3,100	$6,400
Counties Power	41,000	3,200	550	110	13	$15,000	$7,700	$13,000	$36,000
Eastland Network	25,000	4,000	270	59	6.4	$9,300	$6,300	$9,200	$25,000
Electra	45,000	2,200	400	100	20	$10,000	$6,200	$11,000	$28,000
Electricity Ashburton	19,000	3,100	560	160	6.2	$16,000	$8,200	$10,000	$34,000
Horizon Networks	25,000	2,500	530	88	9.9	$7,600	$5,500	$8,700	$22,000
MainPower NZ	37,000	5,000	600	110	7.5	$16,000	$12,000	$16,000	$45,000
Marlborough Lines	25,000	3,400	370	71	7.4	$15,000	$10,000	$16,000	$41,000
Nelson Electricity	9,200	290	140	33	31	$2,700	$1,400	$2,000	$6,100
Network Tasman	39,000	3,600	610	140	11	$11,000	$6,800	$10,000	$28,000
Network Waitaki	13,000	1,900	230	52	6.8	$5,400	$3,700	$5,000	$14,000
Northpower	58,000	6,000	1,100	170	9.7	$17,000	$9,800	$17,000	$43,000
Orion NZ	200,000	11,000	3,100	600	17	$65,000	$37,000	$56,000	$160,000
Powerco	330,000	28,000	4,500	900	12	$100,000	$62,000	$74,000	$240,000
PowerNet	68,000	14,000	1,400	260	4.8	$40,000	$23,000	$25,000	$88,000
Scanpower	6,700	1,000	76	15	6.4	$2,400	$1,400	$2,300	$6,100
The Lines Company	24,000	4,300	380	81	5.5	$12,000	$8,600	$12,000	$32,000
Top Energy	31,000	4,000	320	69	7.8	$15,000	$8,300	$14,000	$37,000
Unison+	120,000	11,000	1,700	340	11	$40,000	$28,000	$39,000	$110,000
Vector Lines	550,000	18,000	8,300	1,700	30	$180,000	$96,000	$110,000	$380,000
Waipa Networks	26,000	2,200	380	73	12	$6,100	$3,500	$6,300	$16,000
WEL Networks	89,000	5,400	1,200	270	17	$34,000	$20,000	$26,000	$80,000
Wellington Electricity	170,000	4,700	2,300	580	35	$39,000	$26,000	$30,000	$96,000
Westpower	13,000	2,300	230	36	5.9	$7,300	$4,300	$8,500	$20,000
Industry total	2,100,000	150,000	31,000	6,500	320	$700,000	$420,000	$560,000	$1,700,000
Industry average	80,000	5,900	1,200	250	12	$27,000	$16,000	$22,000	$65,000

Appendix B: Other considered relationships, asset classes and constituents

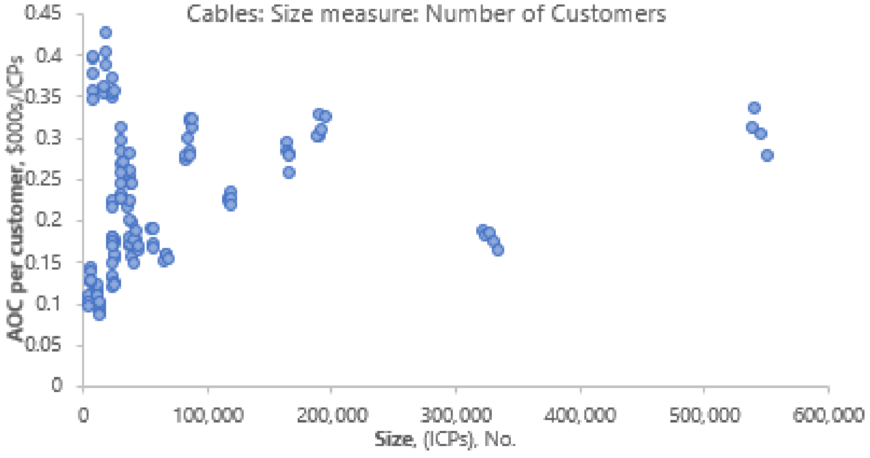
Lines

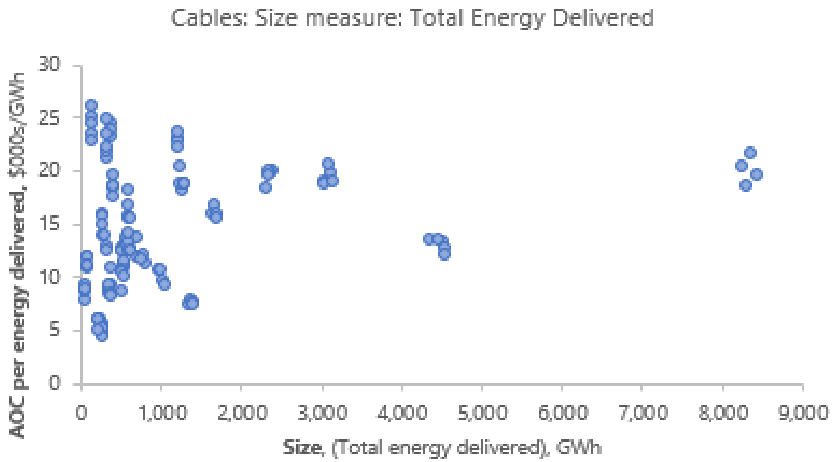


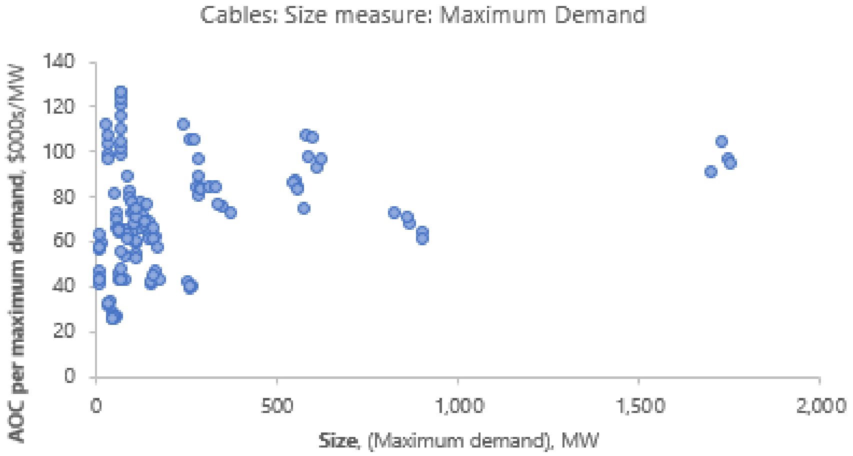




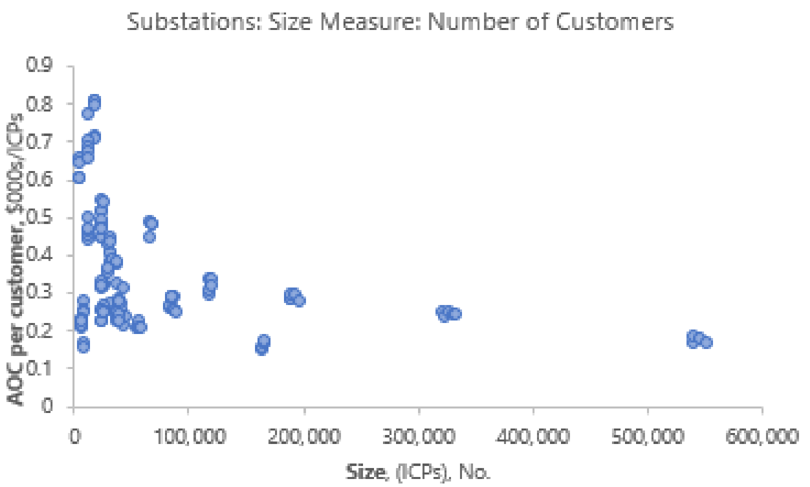
Cables

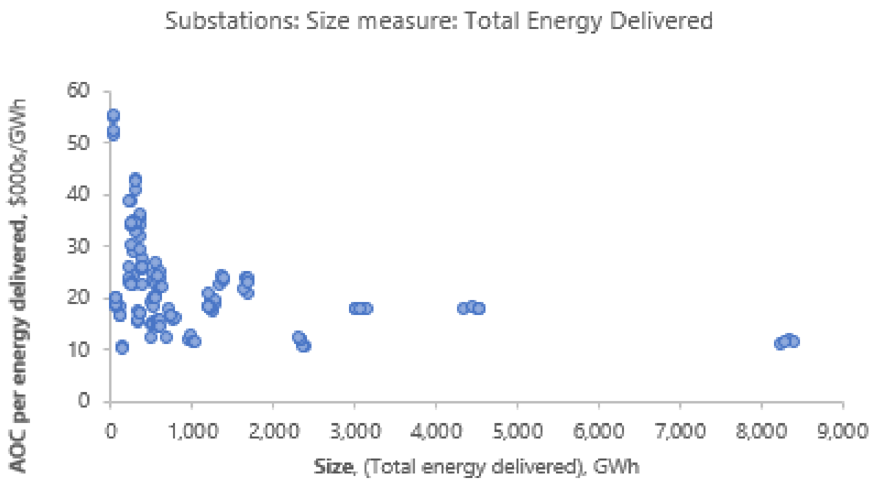

Cables: Size measure: Number of Customers
AOC per customer, $000s/ICPs
0.45
0.4
0.35
0.3
0.25
0.2
0.15
0.1
0.05
0
0
100,000
200,000
300,000
400,000
500,000
600,000
Size, (ICPs), No.

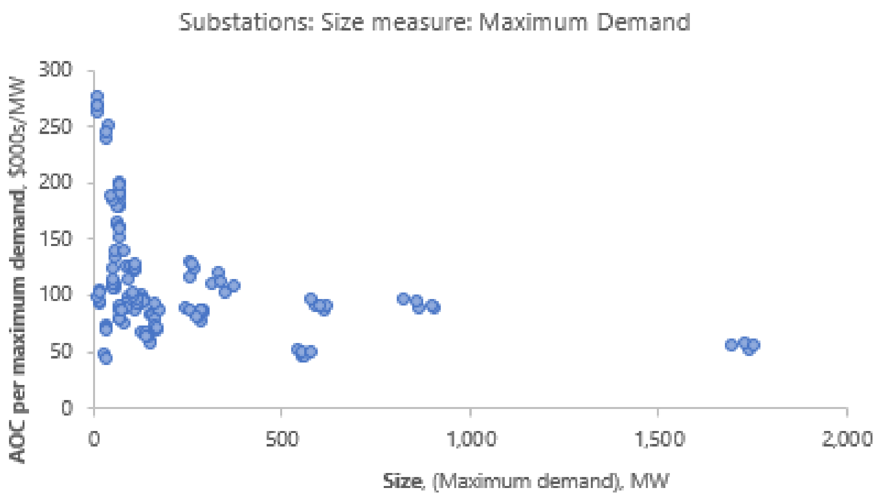

Cables: Size measure: Total Energy Delivered
AOC per energy delivered, $000s/GWh
30
25
20
15
10
5
0
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
8,000
9,000
Size, (Total energy delivered), GWh


Cables: Size measure: Maximum Demand
AOC per maximum demand, $000s/MW
140
120
100
80
60
40
20
0
0
500
1,000
1,500
2,000
Size, (Maximum demand), MW

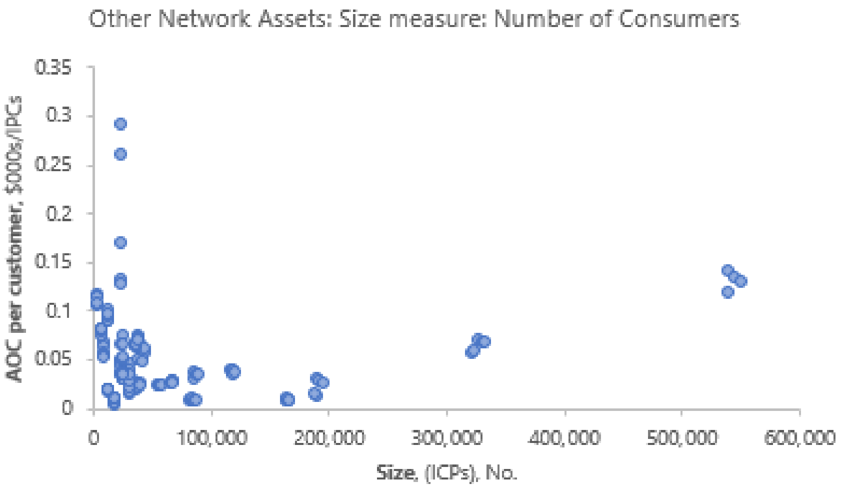
Substations

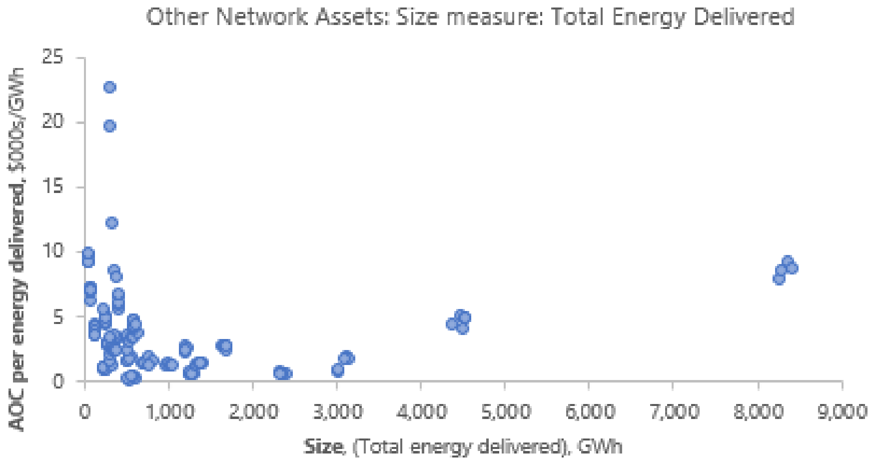


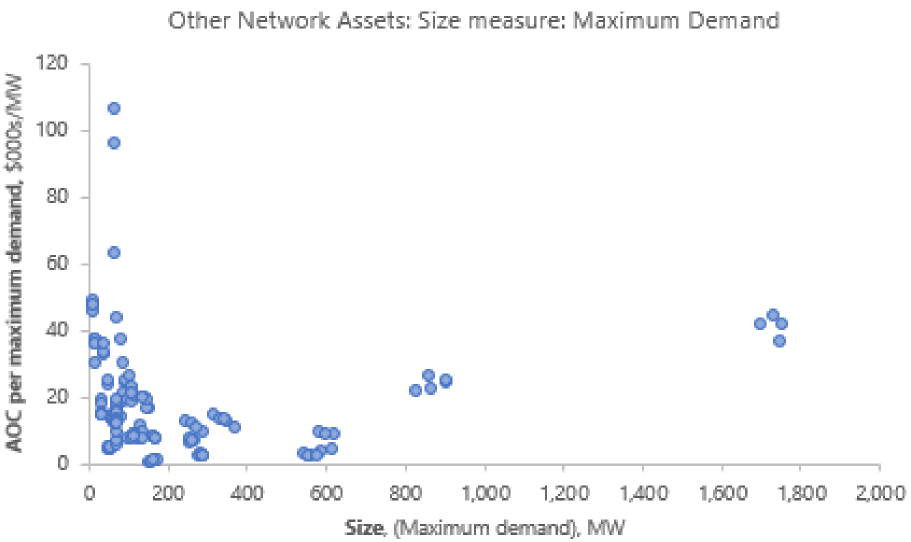




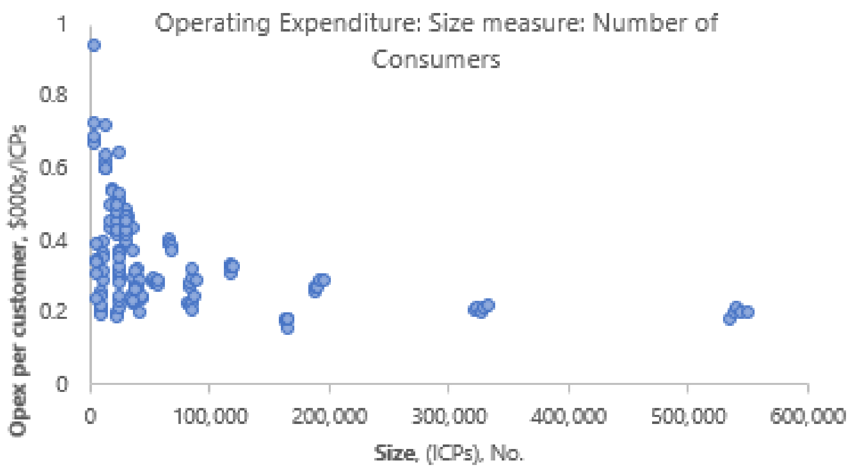
Other Network Assets

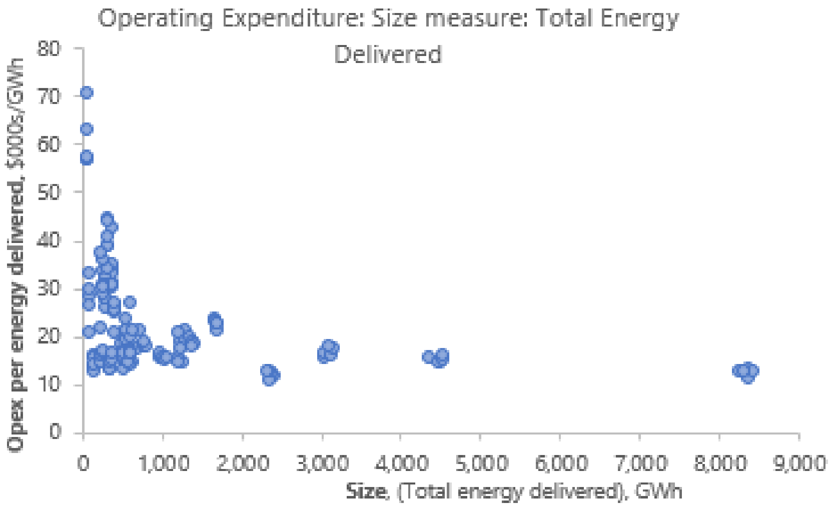


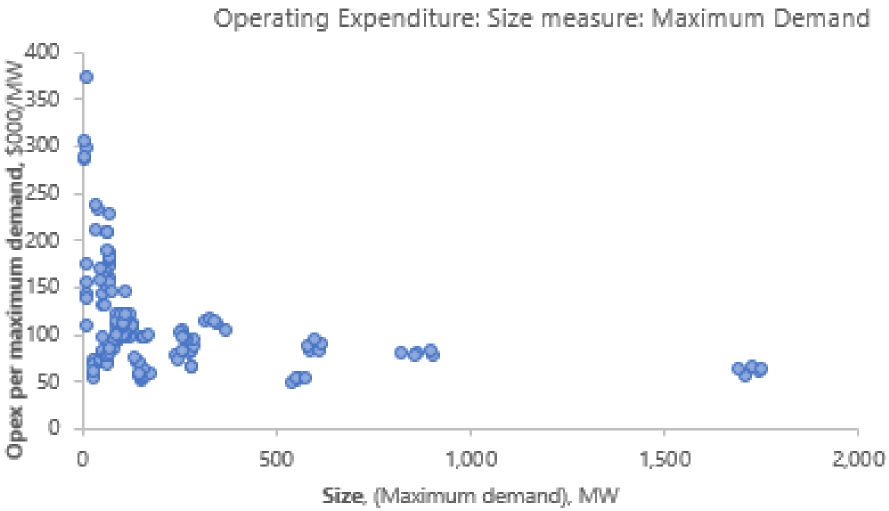




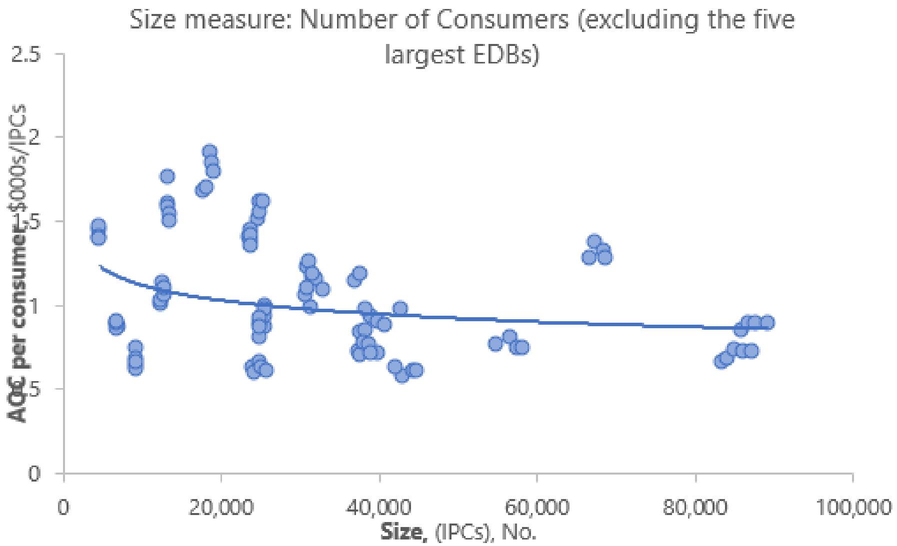
Operating expenditure

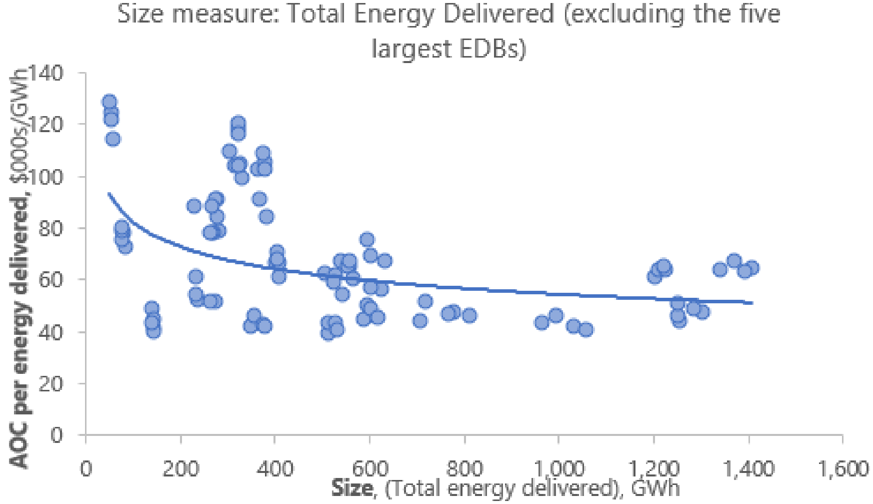


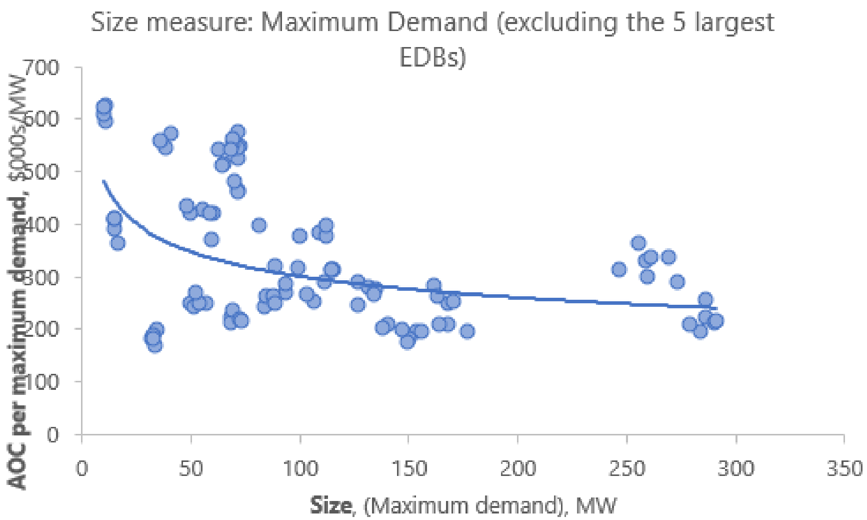




Asset Operating Cost excluding largest 5 EDBs







Appendix C: Interperation of functional form adopted

Model functional form chosen is,

$$y = \alpha x^{\beta}$$

$$\ln(y) = \ln(\alpha x^{\beta})$$

$$\ln(y) = \ln(\alpha) + \beta \ln(x).$$

The regression therefore becomes,

$$y' = \alpha' + \beta x' + \varepsilon$$

which is a simple log-log model.

Therefore, we can interpret the results as,

$$y = e^{\alpha' + \hat{\beta}\ln(x)} = e^{\alpha'} x^{\hat{\beta}}$$

Taking the first derivative of the above w.r.t. X and rearranging gives,

$$\frac{\delta Y}{Y} = \hat{\beta}\frac{\delta X}{X}$$

Meaning,

$$\hat{\beta} = \frac{X}{Y}\frac{\delta Y}{\delta X} = \frac{\frac{\delta Y}{Y}}{\frac{\delta X}{X}} = \frac{\%\Delta Y}{\%\Delta X}$$

which is the elasticity coefficient between X and Y.