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ORIGINAL ARTICLE

Scale properties and efficient network structures in the Swedish electricity distribution market

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Abstract

This paper examines the Swedish electricity distribution sector to highlight three key findings. First, we identify significant economies of scale among electricity distribution firms, indicating that larger firms operate more efficiently. Second, we explore alternative market structures and demonstrate that these can substantially reduce the aggregated costs of electricity distribution. Third, we use novel survey data to show that firms perceive the economic incentives for mergers to be insufficient. These findings suggest that policymakers should consider creating a regulatory environment that encourages consolidation and enhance efficiency in the sector.

Highlights

- In natural monopoly markets, the expectation is few and relatively large firms.
- In the Swedish electricity DSO market, there are multiple firms of different sizes.
- We estimate scale properties based on 171 Swedish firms over 14 years.
- Heuristics are used to derive optimal network structures.
- Results suggest that a cost minimising structure would result in much fewer DSOs.

Keywords Electricity · Network · Economies of scale · Sweden

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1 Introduction

It is widely accepted that electricity distribution system operators (DSOs) are natural monopolies.[1] A substantial empirical literature, using data from several different countries, supports this proposition.[2] When services have natural monopoly characteristics, the expectation is to observe relatively few and large DSOs, each serving a local market. According to the review by Haney and Pollitt (2009), that is also the case in many countries, including Australia, Croatia, Great Britain, Greece, Hungary, Ireland, Lithuania, Netherlands, Portugal, and most of the Latin American countries.

However, some countries, such as Austria, Germany, and the Nordic countries, stand out as having relatively many DSOs, which raises the question whether electricity distribution in these countries do not enjoy the economies of scale found elsewhere. Indeed, many empirical studies have found unexploited scale benefits, including Giles and Wyatt (1989), Filippini (1996), Growitsch et al. (2009), Filippini et al. (2001), Kumbhakar et al. (2015), Mydland et al. (2018). More specifically, Giles and Wyatt (1989) concluded that the optimal number of firms in their setting was 7–9, rather than the 60 they observed in reality. Kumbhakar et al. (2015) find that around 65% of the firms in their sample are operating below the optimal scale. Moreover, Musau et al. (2021) find that mergers in the Norwegian electricity DSO sector could reduce the sector-wide cost level by 22%.

However, previous studies have found small or non-existing effects of regulatory policies aimed at increasing mergers and other consolidations. For example, Clark and Samona (2022) evaluate the impact of government-provided incentives on consolidations among electricity distributors in Ontario, and find that such incentives have had no impact on neither efficiency nor consolidations in that setting.

The purpose of this study is two-fold. The first is to measure the scale properties in the Swedish electricity distribution sector, a sector with relatively many DSOs and with substantial variation in DSO size. These properties are measured using data collected from the Swedish Energy Markets Inspectorate and econometric estimations using average cost as the dependent variable and, similar to Mydland et al. (2020), specify a quadratic cost model.[3] The slope of these models can be interpreted as incentives for consolidation, where a positive slope indicates diseconomies of scale, a slope equal to zero that there are no incentives for structural changes, and a negative slope that there are economies of scale – the more negative, the stronger the incentive for mergers.

[1] This is the typical textbook prediction, which posits that DSOs' average cost is strictly falling as a function of delivered electricity, number of customers and other measures that represent the quantity of their business activities.

[2] See, for example, Giles and Wyatt (1989) for New Zealand, Filippini (1996) and Filippini et al. (2001) for Switzerland, Burns and Weyman-Jones (1996) for England and Wales, Kwoka (2005) for the U.S. and Salvanes and Tjøtta (1994); Kumbhakar et al. (2015), Mydland et al. (2018) and Musau et al. (2021) for Norway.

[3] Some studies have used frontier models, e.g. Kumbhakar et al. (2015) and Musau et al. (2021), but we are not interested in DSOs' level of efficiency and, besides, models where the function passes through the sample mean and where an efficient frontier is estimated tend to find similar scale properties (see e.g. Filippini, 2001). Additionally, some studies use quantile regression, e.g. Mydland et al. (2018), but that comes with the price of not being able to control for the DSO specific effects.

Based on those results, the second purpose of this study is to provide examples of alternative market structures that are more cost efficient. In contrast to Clark and Samano's (2022) more formal approach, we use a heuristic approach under two different sets of assumptions. In the calculation of the first network structure, we take the current structure as a starting point and assume that networks can merge with their neighbours, but that they cannot divest their current assets. This corresponds to a local optimum where smaller DSOs merge into larger units, but where large DSOs are prevented to split up into smaller units. These assumptions are generally accepted among industry stakeholders. When calculating the second network structure, we ignore the current structure and instead use municipality borders as building blocks. Municipalities are generally smaller than the existing networks, which gives us a high degree of flexibility in where revised network borders should be located. This allows us to use the scale properties more effectively than in the first approach and, for example, build new network structures without being restricted by the existing structures. These assumptions imply that the large DSOs can be split into smaller units. For both hypothetical network structures, we compute aggregate cost savings relative to the current network structure.

We use a panel data set with a relatively long time dimension (15 years), which imply that we can control for both the DSO and time specific effects. Many existing empirical studies use cross-sectional data set (e.g., Giles & Wyatt, 1989; Growitsch et al., 2009) or time dimensions that are shorter, e.g., Filippini (1996) and Filippini et al. (2001).

Our econometric results indicate that both the small- and medium-sized firms can reduce their average cost substantially: if number of customers increase by 20%, the decrease in AC for the smallest firms (2,000 MWh of electricity delivered per year) is approximately 27%, and for medium-sized firms (e.g., 200,000 MWh of electricity delivered per year), about 10%. The scale effect for a large firm (5,000,000 MWh of electricity delivered per year) is smaller and amounts to around 2%. This suggests that the aggregate cost savings from improving the market structure may be substantial. Indeed, we show that if we take the current network structure as given and assume that DSOs can merge, but not split, the cost minimising network structure is 9 DSOs. If the current DSOs can both merge and split, the cost minimising structure would be 32 DSOs. This is to be compared to the current market structure with 190 DSOs.

Given these substantial cost reducing potentials, it is puzzling that not more of the small and medium-sized DSOs have merged. To shed light on this, we send out a questionnaire to all DSOs and ask whether they engaged in any mergers or acquisitions in 2018 or 2019, or if they have been involved in attempts that did not materialize in any consolidations. We also ask about the reason(s) for those decisions, regardless of whether they resulted in a merger or not. The questionnaire generated a response rate above 60%, and the responses revealed that only about 5% had been involved in mergers in the last two years. One DSO started a merger process but terminated it when it became clear that it would not result in a net financial gain. Some additional qualitative responses were also received, and they all suggest that mergers were not sufficiently attractive from a financial point of view. In discussions with DSOs, it is revealed that the reasons for these outcomes are (i) many and sudden reg-

ulatory changes have created a high regulatory risk, (ii) insufficient rewards to firms that contribute to cost reductions, and (iii) current owner's desire to maintain control over the assets. These findings lead to recommendations that policymakers ought to promote stable regulatory conditions and to increase the reward for cost reductions.

Our paper contributes to the existing literature in three ways. First, it identifies the scale properties in the Swedish electricity distribution market. The scale properties of Swedish electricity distribution firms have not been thoroughly examined since the study by Kumbhakar and Hjalmarsson in 1998, over 25 years ago. Since then, the sector has undergone several structural and regulatory changes.[4] Furthermore, the Swedish market shares many characteristics with other countries, such as many DSOs per customer and similar regulatory framework with a revenue cap (see, for example, Söderberg & Vesterberg, 2023 for details), which means that the insights from the current paper are applicable in many other countries as well.

Second, it develops a general approach to investigate "scale" that goes beyond the standard focus on "return to scale at the sample mean or median" (used by, e.g., Filippini, 2001). It does so by identifying scale elasticities across the size distribution. This reveals the benefits of mergers and acquisitions for different firm sizes, and allows policy makers to target interventions only to those firms where it would increase welfare. We also ask the DSOs directly for their opinions to collect qualitative aspects not necessarily visible in regulatory data.

Third, we illustrate the policy implications of our empirical estimates by providing examples of alternative market structures, based on either existing DSO borders, or municipal borders. While these back-of-the-envelope calculations ignore possibly important technical and physical aspects of the optimal grid size, they provide illustrate examples of the real-world implications of our results. This is, almost always ignored in the existing literature.

The remainder of the paper is structured as follows. Section 2 describes the Swedish electricity distribution sector. Section 3 describes the data and presents relevant descriptive statistics. Section 4 contains the econometric analyses that form the basis of the scale elasticities. Section 5 describes the hypothetical network structures, and Sect. 6 presents the questionnaire and the responses from the DSOs. Section 7 concludes.

2 Institutional background

During the 1990s, many European countries, including Sweden, deregulated their electricity markets. Regulations were removed in the wholesale and retail markets, which allowed market participants to trade electricity with each other. At the same time, the production and distribution of electricity were vertically separated, i.e., they were not allowed in the same legal entity, and the distribution sector was subjected to price regulation since the networks were considered natural monopolies. Thus, there is no direct way for the DSOs to influence the amount of electricity that is

[4] Although Growitsch et al. (2009) included data from Swedish DSOs for the year 2002, their cross-sectional analysis did not account for DSO-specific effects.

generated. Each Swedish DSO has been given monopoly rights in the concession area where they operate. The Swedish Energy Markets Inspectorate regulates the DSOs, and since 2012 the regulatory framework is based on a revenue cap, outage compensation, and cost-reduction requirements based on Data Envelopment Analysis benchmarks.[5]

In principle, two merging utilities that manage to reduce the average cost for its customers could keep some of the cost savings a few years after the merger. However, the Swedish regulator has decided that all cost saving should to be accounted for in the revenue caps, i.e. they should be transferred to consumers as soon as it is practically possible, which is at the following regulatory period. Thus, the economic benefit to the merging DSOs is limited, particularly when the transition cost is also accounted for.

There are approximately 190 DSOs in Sweden and we have data for 171 of them. This number has declined over several decades, with a reduction rate of approximately one DSO per year.[6] Small DSOs are more likely to be involved in mergers, but a closer look at the smallest DSOs over the last 10–15 years reveal limited organisational activity in that segment.[7] A closer look at mergers reveal that consolidations only occur between DSOs that are close to each other. Most of the acquisitions involved two DSOs that shared a border, while the remaining mergers almost always were in close proximity to each other – typically only a few kilometres apart. To understand how this empirical observation relate to the existence of scale benefits, we proceed to look more closely at the relationship between cost and size.

The firms' cost can be divided into operational and capital costs. Annual operational costs, which on average accounts for approximately 60% of total costs,[8] include costs for labour, maintenance and electricity losses, and annual capital costs (on average 40% of total costs) are calculated based on replacement values, economic lifespan of assets and a discount rate, see Energy Markets Inspectorate (2015) for details. In our empirical analysis, we use annual average cost, which we define as annual total costs divided by the number of customers.

The DSOs differ markedly in terms of size. For example, in 2017, the smallest third of the firms each had less than 50,000 customers, and the three largest (Vattenfall, E.ON, and Ellevio) had 900,000–1,000,000 customers each. Each of the three largest firms were about three times as large as the fourth largest (Göteborg Energi), and they are the only DSOs with networks in several locations. In 2017, 92% of the DSOs had only 34% of the total number of customers. Another way to describe the size heterogeneity is that the largest DSO has as many customers as the sum of the 117 smallest. The size distribution of the DSOs is displayed in Table 1.

[5] For further details, see the Swedish Electricity Act 1997:857 and Söderberg and Vesterberg (2023). Moreover, Duras et al. (2023) and Zeebari et al. (2023) have taken a closer look at how the DSO cost efficiency scores are calculated in Sweden.

[6] In 1970 there were around 900 vertically integrated electricity utilities, most of which were small and owned by customers (Kumbhakar & Hjalmarsson, 1998).

[7] See Appendix A for further details of what has happened to the 25 smallest DSOs over the last 15 years.

[8] Few studies report operational and capital costs separately, but we note that the figures presented here are in line with, for example, those in Vesterberg et al. (2021)

Table 1 Size distribution of Swedish electricity DSOs

Number of customers	Number of firms
< 5,000	51
5,000–10,000	29
20,000–20,000	48
20,000–30,000	19
30,000–50,000	11
50,000–100,000	6
> 100,000	7

Some of the DSOs only serve a few hundred customers. When those DSOs were established at the beginning of the last century, they often started by servicing one large customer (e.g., a large farm or a factory) and eventually grew to also serve other nearby, smaller customers. In our empirical work, we exclude these DSOs since they are structurally different to the majority of DSOs, that have more than several thousand customers and a mixture of large and small customers. All DSOs face the same type of economic regulation, but they are subject DSO-specific revenue caps. Thus, there are no regulatory reasons for why some DSOs are small and some are large.

3 Data

The Swedish Energy Markets Inspectorate collects financial and technical information from each concession-holder annually. A concession holder is synonymous with a DSO, except for the largest DSOs, which operate several concessions. We compile a dataset based on information reported to the regulator from 2004 to 2018 and focus on variables that are essential to understand electricity network scale properties. These variables are total cost, delivered electricity, number of customers, electricity losses, and the price of electricity.

Prior to estimations, outliers are excluded. First, we exclude DSOs that have fewer than 500 customers. The reason for this is not just that they are much smaller than the mean (and median) DSO, but as explained above, they are structurally different. Moreover, observations that are characterised by any of the following are excluded:[9] (i) a variable's value changes by more than 50% from one year to the next, (ii) a value takes a negative or zero value, and (iii) the number of customers declines by more than 5% from one year to the next.[10] Also, DSOs are excluded if they do not have values for all variables for at least four years. In total, 24 DSOs are excluded because of these criteria. This gives a complete estimable sample consisting of 1,946 observations for 171 DSOs. The characteristics of these observations are displayed in Table 2 for each of the variables used in the econometric analysis.

A first thing to note in Table 2 is the substantial heterogeneity across firms in terms of both total costs and outputs. For example, total costs vary from around 1,884,000 SEK to more than 4 billion SEK. The DSOs with the lowest total costs

[9] Note that these conditions only exclude single observations and not an entire DSO/concession area.

[10] In general, network length never decreases from one year to the next. Number of customers can, and do, decrease from one year to the next, but realistic rates of decline are very small.

Table 2 Descriptive statistics

Variable [unit]	Mean	Std. Dev.	Min	Max
Total costs [thousand SEK]	122,649	465,758	1,883.9	4,346,250
Delivered electricity [MWh]	648,717	2,246,326	3379	1.88×10^7
No. of customers [#]	36,354	132,894	511	1,031,639
Loss [MWh]	26,344	95,534	182	1,022,911
Price of electricity [SEK per MWh]	0.531	0.676	0.032	667.75

Note 1,946 observations in total

Table 3 Average cost [SEK per kWh] across percentiles

Percentile	(Number of customers) [a]	Avg cost
1	619	0.425
5	1,369	0.325
10	2,281	0.235
25	4,238	0.188
50	10,409	0.169
75	19,874	0.168
90	41,346	0.185
95	61,637	0.192
99	882,221	0.238

Note[a] Rounded to the nearest hundred

are typically small cooperatives. As mentioned, the DSOs with the highest total costs are Vattenfall, owned by the Swedish state, Ellevio (previously Fortum) and E.ON, both of which are owned by foreign, private investors. The heterogeneity in number of customers and other firm characteristics is also large. For example, the standard deviation of delivered electricity is very large in relation to the mean, again highlighting the large heterogeneity across firms. Network losses are closely correlated with the amount of delivered electricity, and exhibits similar variation. Finally, the price of electricity (which DSOs pay to cover network losses) varies substantially. A lot of this variation is temporal, with prices in general being much higher during winter months compared to summer months, but some of this variation also stems from regional differences in electricity prices.

To get a sense for the economies of scale, we calculate average costs for different firm sizes, where size is represented by number of customers. These cost values are presented in Table 4 for different percentiles of number of customers. If there are unexploited economies of scale, this should translate into lower average costs for larger firms. As displayed in Table 3, the average cost is clearly higher for smaller firms, and relatively large firms (around the 90th percentile) have the lowest cost. In particular, the lowest average cost in the sample is less than half of the highest average cost. Interestingly, the average cost for the largest firms (99th percentile) is slightly higher than that for the 90th percentile.[11] Although these patterns can change

[11] The performance of the 99th and 100th percentiles is important since these DSOs account for about half of the total number of customers, and even more of the aggregated costs (see Tables 1 and 3).

when other factors that affect cost are controlled for, it nevertheless suggests that the largest DSOs may not have the lowest cost, i.e., that they are "too large".

If all firms had the same average cost as the 75th percentile, i.e., an average cost of 0.17 SEK per kWh, then the distribution cost would be approximately 18% lower than under the current structure. In a similar vein, if all firms were of the same size as the 75th percentile (approximately 20,000 customers), there would only be about 130 DSOs in Sweden. Thus, if all scale advantaged were exploited, the implications would be substantial. However, and as we will discuss later, there are restrictions on possible mergers, which means that not all the unexploited economies of scale are easily reaped through mergers. For example, mergers typically make sense for neighbouring network areas, and it is easier to merge small firms than to break up large firms. We detail in Sect. 5 how these constraints may influence the extent to which economies of scales may be realized.

4 Analysis of scale properties

While the descriptive statistics in Table 3 suggest that there are unexploited economies of scale, and possibly also diseconomies of scale for the largest firms, it is useful to proceed with a more rigorous econometric analysis since the descriptive analysis ignores other potentially relevant explanatory factors. Thus, in this section we estimate cost functions, which allow us to compute cost elasticities at different percentiles. Intuitively, one would expect high percentiles to have a size elasticity of cost, relatively closer to unity.

We estimate average cost (AC) functions that are assumed to be additively separable in outputs and input prices. AC is calculated as total cost divided by delivered electricity. The process of distributing electricity is assumed to consist of one output, i.e., number of customers (N), and one input price: the price of electricity (p^{el}).[12] While our choice of output variable, as well as input prices, is similar to those used in several previous studies (see, e.g., Triebs et al., 2016), it should be noted that the choices of output and input variables differ across studies, and in many cases depend on the availability of data. For example, Mydland et al. (2020) use kilometres of high-voltage network and number of customers as outputs, and they do not include input prices due to limited cross-sectional variance in these prices. In our data, the price of electricity varies across both time and firms. Kumbhakar et al. (2015) define a model where there are three outputs: amount of delivered electricity, number of customers, and the length of the network. However, and as discussed by Triebs et al. (2016), when these outputs are included in a model, they tend to create multicollinearity,[13] and for that reason we use a more parsimonious specification.

[12] We also estimated a specification where we included the price of capital but because of limited within-variation, it gave unrealistic results and it was therefore excluded.

[13] Using raw data from the Swedish Energy Markets Inspectorate, the correlation between delivered electricity and number of customers is 0.997 and the correlation between delivered electricity and cable length is 0.966.

Furthermore, we add the following control variables: network losses (L), number of concession areas[14], DSO fixed effects and year fixed effects. The amount of network losses can be viewed as a hybrid measure that is determined by load, network length, and share of low voltage deliveries. Thus, L captures network congestion, network size and type of customers. A higher pressure on the system, i.e., a high load factor, is likely to increase losses, which is expected to increase costs. Losses also increase if electricity is distributed over relatively long distances, and a higher share of high voltage deliveries is associated with less losses. Our results are not affected in any qualitative way if network losses are excluded.

In cold climates, such as in Sweden, the strongest determinant of per-capita delivered electricity is the demand for heating. We have access to data from weather stations that record daily temperatures, and after having identified the closest weather stations and calculated the heating degree days (HDD) for each DSO and year, we add that variable as well. The price of electricity, p^{el}, is included because DSOs purchase electricity to cover network losses and pay for transit on the high voltage network. This price is calculated as the total cost of transit and losses divided by the sum of losses and high voltage deliveries.

Cost functions that represent physical networks have been specified using various approaches, such as the Cobb-Douglas form (e.g., Söderberg, 2008), the Translog form (e.g., Söderberg, 2011 and Triebs et al., 2016), the quadratic form (e.g., Jamasb & Söderberg, 2010 and Mydland et al., 2020), and forms derived based on theoretical, energy-specific, principles (e.g., Boscan & Söderberg, 2021). At a minimum, the chosen specification should be able to identify both linear and nonlinear output effects and both economies and diseconomies of scale. We choose to use a quadratic cost function.

There is no consensus regarding what variables to include[15] and what specification to choose.[16] In this study, we estimate a range of reduced-form specifications, where we include a quadratic form of N and where different squared and interaction terms are included in the four different specifications.[17] Specifically, Eq. (1) includes squared terms of L, Eq. (2) includes squared terms and an interaction between N and L, and Eq. (3) includes no squared or interactions terms for the control variables. Equation (4) is similar to Eq. (1) but includes heating degree days (HDD) as an extra covariate. Since increased HDD is equivalent to higher demand, HDD can be

[14] Some DSOs (in particular the larger ones) serve more than one concession area. This may affect costs if, for example, DSOs are able to exploit economies of scale across such concession areas.

[15] Many of the variables linked to cost are highly correlated, and may cause multicollinearity problems if all of them are included in the estimation. To illustrate, the correlation between number of customers and cable length is 0.92, and the correlation is equally high for many of the other firm characteristics. Furthermore, most of these variables are more or less constant during our sample period (e.g., km of line length, rural vs. urban) and are therefore captured by the firm fixed effects. To illustrate, firm and year fixed effects account for approximately 98.9% of the variation in customer density.

[16] See, e.g., the literature review by Söderberg (2008, pp. 65–66).

[17] The rationale for the quadratic form, rather than the more frequently adopted translog, is threefold (Färe et al., 2009; Shaffer, 1998): (i) the quadratic form handles many fixed terms more readily, (ii) it does not rest on the profit-maximizing assumption (which is likely to be overly restrictive for publicly owned utilities) like the translog form, and (iii) the quadratic form has been found to generally outperform most other forms, including the translog.

interpreted as a proxy for network load. Higher HDD increases the need for preventive maintenance and can therefore be cost inflationary. All continuous variables are in logs. The four specifications can be formulated as:

$$AC_{it} = \alpha_0 + \alpha_1 N_{it} + \alpha_2 N_{it}^2 + \alpha_3 L_{it} + \alpha_4 L_{it}^2 + \alpha_5 p_{it}^{el} + \boldsymbol{\lambda}_{it} + \boldsymbol{\theta}_t + \epsilon_{it}, \quad (1)$$

$$AC_{it} = \beta_0 + \beta_1 N_{it} + \beta_2 N_{it}^2 + \beta_3 L_{it} + \beta_4 L_{it}^2 + \beta_5 N_{it} L_{it} + \beta_6 p_{it}^{el} + \boldsymbol{\lambda}_{it} + \boldsymbol{\theta}_t + \epsilon_{it}, \quad (2)$$

$$AC_{it} = \gamma_0 + \gamma_1 N_{it} + \gamma_2 N_{it}^2 + \gamma_3 L_{it} + \gamma_4 p_{it}^{el} + \boldsymbol{\lambda}_{it} + \boldsymbol{\theta}_t + \epsilon_{it}, \quad (3)$$

$$AC_{it} = \theta_0 + \theta_1 N_{it} + \theta_2 N_{it}^2 + \theta_3 L_{it} + \theta_4 L_{it}^2 + \theta_5 HDD_{it} + \theta_6 p_{it}^{el} + \boldsymbol{\lambda}_{it} + \boldsymbol{\theta}_t + \epsilon_{it}, \quad (4)$$

where i is DSO, t is year, $\boldsymbol{\lambda}_{it}$ is a vector that consists of DSO fixed effects and number of concessions (which vary across both DSOs and years), and $\boldsymbol{\theta}_t$ is a vector of year fixed effects. ϵ_{it} is the random noise term, which is assumed to be i.i.d., and $\boldsymbol{\alpha}$, $\boldsymbol{\beta}$, $\boldsymbol{\gamma}$, and $\boldsymbol{\theta}$ are vectors of parameters to be estimated.

Equations (1)–(4) are estimated with the within-estimator, and standard errors are clustered at the DSO level.[18] The full estimation output is displayed in Table 4, and in Table 5 we display the scale elasticities, which we evaluate at different percentiles of N for each equation, similar to Mydland et al. (2020). To illustrate, for Eq. (1), $\frac{\partial AC}{\partial N}\frac{N}{AC} = (\alpha_1 + 2\alpha_2 N_{it})$, which means that the effect on the average cost of a change in N depend on firm size (i.e., the number of customers). This allows us to explore how the scale elasticity vary across the distribution of firms.

Starting with Table 4, we note that the effect of a change in the number of customers, and number of customers squared, on the average cost is very similar across our four specifications, with a parameter estimate of approximately −1.8 and an estimated parameter for number of customers squared of approximately 0.08 (although somewhat larger for the second specification). For all these estimates, the standard errors are large, and the estimates are not statistically significant. However, we are mostly interested in the elasticity of cost with respect to the number of customers, and this elasticity may be statistically significant even if the individual parameters are not. To understand whether the elasticities are estimated with precision, and what these parameters imply in terms of scale economies, we next turn to the elasticities in Table 5.

To begin with, all elasticities, except those at the 99th percentile, are negative and statistically significant, suggesting that the average cost function is falling for almost all of the DSOs. Broadly speaking, the elasticity enjoyed by the smallest DSOs is around −0.8 and by the largest around 0.3. The results at the sample mean are similar to those in previous studies based on data from the Nordic countries (e.g., Kumbhakar & Hjalmarsson, 1998, Kumbhakar et al., 2015, Mydland et al., 2018, and Mydland et al., 2020).

[18] Since our interest is in the scale properties of the cost function rather than measuring cost efficiency, we do not estimate a stochastic frontier model. For recent studies on the efficiency of Swedish DSOs, see, for example, Vesterberg et al. (2021), Zeebari et al. (2023) and Lundgren and Vesterberg (2024).

Table 4 Estimation output from Eqs. (1)–(4)

Variable	Equation (1) Coeff (S.E.)	Equation (2) Coeff (S.E.)	Equation (3) Coeff (S.E.)	Equation (4) Coeff. (S.E.)
Number of customers	-1.842	-1.836	-1.874	-1.851
	(1.221)	(1.202)	(1.226)	(1.228)
Number of customers squared	0.0783	0.106	0.0788	0.0788
	(0.056)	(0.070)	(0.056)	(0.056)
Loss	0.224**	0.320*	0.0846***	0.221*
	(0.112)	(0.170)	(0.019)	(0.113)
Loss squared	-0.00828	0.0153		-0.00814
	(0.007)	(0.023)		(0.007)
Number of customers × Loss		-0.0559		
		(0.057)		
Heating degree days				0.000
				(0.000)
Price of electricity	0.189***	0.190***	0.186***	0.189***
	(0.037)	(0.037)	(0.037)	(0.036)
Number of concession areas	Yes	Yes	Yes	Yes
DSO FE	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes
Constant	7.553	7.034*	8.383	7.579
	(6.374)	(6.144)	(6.399)	(6.391)
R2 (within)	0.528	0.529	0.528	0.528
N	1946	1946	1946	1946

Note All variables are logged. Standard errors in parentheses. * $p<0.1$, ** $p<0.05$, *** $p<0.01$

Table 5 Elasticities at different percentiles for eqs. (1)–(4)

Percentile (Number of customers) [a]	Equation (1)	Equation (2)	Equation (3)	Equation(4)
1st (200)	-0.834*	-0.816*	-0.861*	-0.838*
5th (1,000)	-0.696*	-0.678*	-0.722*	-0.698*
10th (1,800)	-0.625*	-0.606*	-0.651*	-0.627*
25th (4,100)	-0.528*	-0.515*	-0.553*	-0.529*
50th (10,200)	-0.390**	-0.376***	-0.415**	-0.391**
75th (19,500)	-0.282**	-0.267**	-0.306**	-0.282**
90th (40,800)	-0.163***	-0.150**	-0.187***	-0.163***
95th (61,400)	-0.108**	-0.107*	-0.131**	-0.107**
99th (874,300)	0.305	0.318	0.285	0.308

Note[a] Rounded to the nearest hundred. Standard errors are estimated using the delta method. * $p<0.1$, ** $p<0.05$, *** $p<0.01$

The fact that the elasticities are positive (although statistically insignificant) for the largest DSOs indicates that they have exceeded the cost minimizing point and that they operate at upward sloping section of the AC-function. Thus, the largest DSOs should evaluate future acquisitions carefully to avoid welfare reductions. There is also a more general danger in pushing N beyond its current maximum point since it is uncertain what the functional properties look like when values are extrapolated.

Previous studies have also found that the largest DSOs are "too large". For example, Kumbhakar et al. (2015) found that the 2–6% largest Norwegian DSOs have a size that is a least 5% above the optimal level. For the small- and medium-sized DSOs, it is clear that they can lower their average cost if they increase N.

Based on the estimated elasticities, Table 6 gives detailed insights about how the average costs is affected by increases in N (using the empirical results from Eq. (1)). The AC baseline (column 2) reports current AC levels using the actual values of control variables and input price, which is the reason AC is higher for the 95th percentile than for the 90th percentile.[19] Since the smallest DSOs (1st percentile) have an average cost that is about twice as high as the DSOs in the other tail of the distribution (e.g., 90th and 95th percentiles), the smallest DSOs can make substantially larger savings by increasing their customer bases. For example, a 10% increase in N results in an absolute decrease of the AC that is 10–20 times as large for the smallest DSOs as it is for some of the largest DSOs. If the increase in N is fixed at a certain number of customers, then the smallest DSOs have incentives to merge that are more than 100 times greater than the largest firms. In Sect. 7, we report the results from a qualitative survey on consolidations and reasons for why DSOs have or have not engaged in consolidations.[20]

In addition to Eq. (1) to (4), we also estimate a range of specifications as sensitivity analysis. For example, we include cable length and the share of industrial customers as additional controls to each of our four specifications. These estimations do not change our results in any substantial ways. We also use a split-sample approach and estimate the model separately for the early and late years of our sample, and again, this does not change our results to any large extent, and the qualitative insights remain. These results are available upon request.

Table 6 Average cost (AC) baseline values and how AC is affected if N increases

Percentile	Number of customers[a]	AC baseline	AC when N increases by 10%	AC when N increases by 20%
1	1,220	0.280	0.257	0.233
5	1,804	0.276	0.257	0.238
10	2,640	0.291	0.272	0.254
25	4,690	0.234	0.221	0.209
50	10,915	0.195	0.187	0.180
75	20,318	0.166	0.161	0.156
90	42,345	0.149	0.147	0.144
95	63,512	0.169	0.167	0.165
99	882,772	0.198	0.204	0.210

Note[a] Rounded to the nearest hundred

[19] Note that these baseline costs differ from those presented in Table 3, since we here use the estimation results, and in Table 3 use the raw data without controlling for any covariates.

[20] Given the results in this section, it is unlikely to see divestitures. However, we do not restrict responses from DSOs that describe divestitures, nor do we explain why they engaged or did not engage in divestitures.

5 Hypothetical network structures

Given the results presented in Sect. 4, the cost minimizing number of customers is approximately 160 000. Specifically, we use the estimated cost function in Sect. 4 and find the cost-minimizing number of customers by taking the derivate of AC with respect to N and setting the derivative to zero.[21] To achieve that market structure, existing firms would need to be able to adjust their size marginally. In reality, however, mergers between firms typically depart from existing administrative borders, treating these borders as constraints. Therefore, achieving the mathematically optimal firm size may be impossible. Technical and physical characteristics of DSOs (e.g., the location of cables and transformer stations) introduce additional constraints.

In this Section, we present hypothetical network structures based on the results outlined in Sect. 4 and cost minimising heuristics. We explore how these alternative structures would change the aggregate cost of the Swedish local electricity networks. More specifically, we outline two hypothetical network structures based on different assumptions that departs from existing DSO borders or other relevant administrative borders. The first structure is based on the idea that the existing, small and medium-sized networks could lower their average cost by merging with neighbouring networks, taking existing grid borders as given. The second structure is based on the less restrictive idea that small DSOs can merge into larger networks *and* that large DSOs can split into smaller networks, using municipality borders to define the size of the alternative market structure instead of existing grid borders. Both these assumptions reflect the fact that any merger between firms will be based on existing administrative borders.

As a reference for the two hypothetical structures, the existing structure has an average cost of 0.200 SEK per kWh and it consists of 171 unique DSOs (in our sample; see Sect. 3 for details). To understand what the cost reducing potential is for each hypothetical network structure, we use the econometric estimates to compute the predicted average cost for all the three different structures, i.e., the existing and the two hypothetical ones. Since we do not observe network losses for non-existing DSOs, or per municipality, and since it is not obvious what the losses after mergers are,[22] we estimate the AC-model assuming that parameters related to losses are zero for our hypothetical market structure. This does not influence the final estimates in any noticeable way. To illustrate, the main empirical model suggests an optimal size of 158 984 customers and when we ignore network losses, the optimal size changes to 160 275 customers.

5.1 Existing DSOs can (only) merge

Allowing smaller DSOs to merger into larger networks closely resembles the transformation that has taken place during the last decades, where mergers exclusively

[21] This is substantially higher than what the descriptive statistics suggested in Sect. 4. Thus, when relevant control variables are added, the conclusion changes.

[22] In particular, our data suggest a non-linear and somewhat complicated association between number of customers and losses.

has involved two networks that share border. Thus, this hypothetical transformation is restricted to mergers and we exclude the possibility that large networks split into smaller networks. Given the empirical estimates, we allow mergers to take place until a network (approximately) reaches the cost minimising size of 160 000 customers. Using this heuristic leads to nine networks with an average cost of 0.122 SEK per kWh. This corresponds to an aggregate cost saving of approximately 35%. The proposed market structure here is one example of many potential structures. However, since the cost of the new grid is driven by the number of customers in the new DSO, any mergers that results in a similar number of customers will yield similar cost reductions.

5.2 Existing DSOs can merge and split

In the second hypothetical network structure, we ignore existing network borders and instead use municipals as low-level building blocks for the creation of a new structure (there are 290 municipalities in Sweden). As in Sect. 6.1, we only consider adding a municipality to an existing network if it shares border with that network. Municipalities are added until a network consists of approximately 160 000 customers. We split the two largest municipalities, i.e. Stockholm and Gothenburg, into three and two networks, respectively, to avoid over-sized networks. While this network structure is unrealistic in the sense that it does not consider the location of cables and transformer stations, it does allow us to not only merge small networks into larger networks, but it also allows us to split large DSOs into smaller ones. Despite that it is an approximation, we still believe that it provides a usable illustration of the cost saving potential that economics of scale have in the sector.

In our second market structure, which consist of 32 network areas, the average cost is 0.120 SEK per kWh, which is slightly lower than in our first scenario. This structure is displayed in Fig. 1. Unfortunately, we do not have access to geographical data (e.g., GIS-data) for the existing network structure,[23] which means that we are unable to provide a similar figure for the previous scenario.

The numerical exercises presented in this section allow us to draw several relevant conclusions: first, the cost savings from reducing the number of DSOs in Sweden are substantial, amounting to more than 30%. Second, these cost savings originate from merging the small networks to larger network areas, and the extra cost savings from breaking up the largest networks, which we learn about through a comparison between the first and the second market structure, are negligible.

[23] While such geographical data is available from the Swedish transmission system operator (see https://www.natomraden.se/), the data quality is too poor to provide a meaningful illustration. For example, the location of several networks is missing.

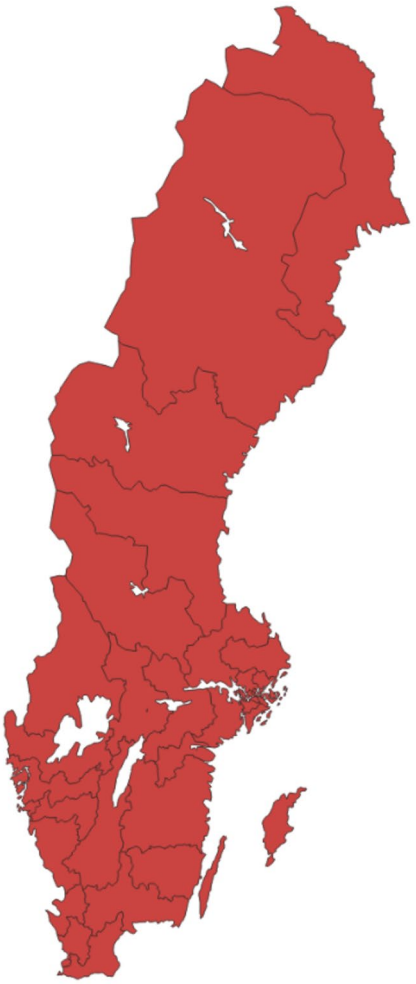

Fig. 1 Optimal network structure if small networks can be merged, and large networks can split. Number of unique networks: 32

6 Questionnaire to DSOs

Annual regulatory statistics do not contain information about ownership, which creates a delay in when information about mergers and acquisitions becomes available. Thus, the first question we asked DSOs is what ownership transactions they were involved in from January 1, 2018 to December 31, 2019. There are several potential reasons for why DSOs were, or were not, involved in consolidation processes with other DSOs. No attempts to merge could, for example, be due to scale economies having been exhausted, the regulatory framework not creating incentives for mergers, current owners not wanting to lose their influence over important investment or pricing decisions, general delays that make it looks like the level of activity was low, or the current owners having objectives that are different from those of potential buyers. One way to learn about the decisions made by the DSOs is to ask them directly.

Table 7 Mergers and acquisitions in 2018 and 2019 revealed by DSOs responses

	Before the acquisition Buyer	Target firm	After the acquisition New firm
Transaction 1:			
DSO	Lidköping kommun	Vinninga elektriska förening	Lidköping kommun
Number of cust.*	21,827	824	22,651
Average cost**	0.316	0.288	0.313
Cost saving			1.01%
Transaction 2:			
DSO	Kraftringen Energi AB	Skånska Energi elnät AB	Kraftringen Energi AB
Number of cust.*	100,647	18,725	119,372
Average cost**	0.029	0.040	0.029
Cost saving			0.4%
Transaction 3:			
DSO	Ellevio	Hamra Besparingsskog	Ellevio
Number of cust.*	959,944	514	960,458
Average cost**	0.037	0.431	0.037
Cost saving			-0.01%
Transaction 4:			
DSO	Falu Elnät AB	Envikens Elnät AB	Falu Elnät AB
Number of cust.*	32,105	1,181	33,286
Average cost**	0.033	0.227	0.033
Cost saving			0.7%
Transaction 5:			
DSO	Ellevio	Vallentuna Elnät AB	Ellevio
Number of cust.*	959,944	14,732	974,676
Average cost**	0.037	0.051	0.037
Cost saving			-0.4%

* Number of customers before the acquisition is the value the year before the transaction took place. Number of customers after the transaction is the sum of the two numbers before the transaction

** The average cost is calculated based on Eq. (1) with the parameters reported in Table A1, but with the parameters for loss set to zero

The questionnaire was sent out to all firms that report financial and technical statistics to the Swedish Energy Markets Inspectorate on an annual basis. The response rate reached 63% after a reminder (responses received from 96 DSOs). The sample is very similar to the population in terms of average cost and number of customers. Importantly, two of the three largest DSOs responded, which means that the results apply to those outliers as well. Two DSOs replied that they did not want to participate in the survey. Table 7 displays the transactions that were revealed from the questionnaire. The table shows the predicted average costs for both buyers and acquired organizations prior to, as well as after, the transactions.[24] In addition to the transactions reported in Table 7, one respondent revealed that the DSO had initiated

[24] As with the calculations in Sect. 8, we do not know how losses change with these mergers. Therefore, we set these parameters to zero. However, and as already alluded to, this does not influence the final estimates in any noticeable way.

an acquisition process, but that it withdrew from the process after realizing it would not be as profitable as initially expected. Another DSO replied that it had submitted a number of bids to purchase other DSOs, but that they had not been accepted by the target owners. A total of three DSOs claimed that they had investigated the potential to purchase neighbouring networks but that they did not progress with that when they realised that the financial gains to them were minimal. Nothing that is revealed in the survey suggests that this view has changed over the last few years.

Five of the DSOs that responded to the questionnaire reported that they had been involved in consolidations. Thus, the conclusion is that merger and acquisition intensity remain low in the industry, despite the noticeable benefits it can bring. Ellevio, one of the three largest, has continued to purchase smaller firms, but as shown above, there is no guarantee that with as many customers as Ellevio has, that consolidations will reduce the average cost. Rather, our empirical model suggests that Ellevio's cost have increased, albeit only very slightly. However, the DSOs that were acquired are all relatively small and they have enjoyed noticeable cost reductions. The firms gave only one reason for not being more active, either as an acquirer or a target, namely that the financial gains were not large enough. Of course, this does not mean that mergers and acquisitions do not result in cost savings, but that the DSOs involved do not get to keep the rewards that follow the structural change. No firm claimed to avoid consolidation because it did not want to lose influence over important business decisions, or in order to self-regulate according to its own values and preferences.

7 Conclusions and policy implications

The analyses in this study show that there is substantial cost reducing potential in the Swedish electricity distribution sector. Specifically, if every DSO that has fewer than the cost-minimising number of customers (approx. 160 000), merged so they become part of a DSO with $\geq$ 160 000 customers, the average sector cost per delivered kWh would fall by 35%. A few Swedish DSOs have more, or even many more, customers than the cost-minimising number, but splitting the largest networks into smaller, has a negligible effect since the cost curve is almost flat for the largest firms. Moreover, given that splitting assets is often practically more complex and face more resistance from stakeholders, we see no reason for why policy makers should consider that moving forward. Given the potential mergers have, there have been surprisingly few consolidations during the last decades and when asked, the DSOs claim they have very limited interest in engaging in merges.

The results in this study lead to a number of policy implications. First, policy makers and regulators should provide clearer incentives for mergers. As our survey shows, although there are substantial gains to be made at the aggregate level, firms perceive their own potential benefits from mergers to be small. For example, policy makers could reduce the administrative burden of mergers, or adjust the revenue cap to make the financial gains from mergers larger. Second, the results clearly show that the societal benefits from mergers between large firms are small or even negative. Therefore, policy makers should design incentive mechanisms for mergers such that the benefits are larger for smaller firms than for large firms. Third, we give examples

of two alternative market structures that would capture the unexploited economies of scale and show that the aggregate cost savings can be substantial. Even when departing from existing grid area borders, which should account for at least some of the technical and administrative constraints that likely exist on mergers, the cost savings are large. Using other administrative borders does not increase the aggregate cost savings to any larger extent.

As a final remark, this study has focused exclusively on the supply side of the electricity distribution sector. To understand how proactive policy makers should be in promoting mergers and acquisitions, we also need to understand the motivations of network owners and customers and what the total welfare implications would be if consolidations were incentivized more strongly than today. We leave the demand side of this issue for future research.

Appendix A

This appendix takes a closer look at what has happened to the DSOs that were the smallest in 2005 and follow them until 2017. As displayed in Tabel A1, six of them merged with other DSOs – some of them with the largest (Vattenfall and Fortum/Ellevio) and the others with much smaller ones (Sandviken Energi, Linde Energi, Gävle Energi, and Brittedals Elnät). The remaining 19 DSOs exist in the same organizational form as they did 12 years earlier.

Table A1 Development of the DSOs that were the 25 smallest in 2005

The 25 smallest DSOs in 1998/1999	One of the 25 smallest DSOs in 2005?	One of the 25 smallest DSOs in 2010?	One of the 25 smallest DSOs in 2017?	Comment
LJW Nät HB	Yes	Yes	No	Owned by Vattenfall and incorporated in one of Vattenfall's concession areas in 2014. Vattenfall was a neighboring DSO that shared a border with LJW Nät HB.
Sturefors Eldistribution AB	Yes	Yes	Yes	
Hamra Besparingsskog	Yes	Yes	Yes	
Almnäs Bruk AB	Yes	Yes	Yes	
Österfärnebo El eko. för.	Yes	Yes	No	Owned by Sandviken Energi and incorporated in Sandviken Energi's concession area in 2017. Sandviken Energi was a neighboring DSO that shared a border with Österfärnebo El eko. för.
Vinninga Elek. för.	Yes	Yes	Yes	
Envikens Elnät AB	Yes	Yes	Yes	
Årsunda Kraft & Belysningsför. upa	Yes	Yes	Yes	
Olseröds Elek. Distr.för. upa	Yes	Yes	Yes	

Table A1 Development of the DSOs that were the 25 smallest in 2005

The 25 smallest DSOs in 1998/1999	One of the 25 smallest DSOs in 2005?	One of the 25 smallest DSOs in 2010?	One of the 25 smallest DSOs in 2017?	Comment
Närkes Kils Elektriska eko. för.	Yes	Yes	No	Acquired by Linde Energi 1 Jan 2015. Närkes Kils Elektriska eko för was a close neighbor but did not share a border with Linde Energi.
Blåsjön Nät AB	Yes	Yes	Yes	
Hedesunda Elektriska AB	Yes	Yes	No	Owned by Gävle Energi AB, and incorporated in Gävle Energi AB's concession area, from 2011. Hedesunda Elektriska AB was a neighboring DSO that shared a border with Gävle Energi AB.
Skyllbergs Bruks AB	Yes	Yes	Yes	
Töre Energi eko. för.	Yes	Yes	Yes	
Hjärtums Elförening eko. för.	Yes	Yes	Yes	
Hallstaviks Elverk eko. för	Yes	Yes	Yes	
Mellersta Skånes Kraft	Yes	Yes	Yes	
Näckåns Elnät AB	Yes	Yes	Yes	
Nor-Segerstad	Yes	No	No	Incorporated in Fortum's concession area 2006. Nor-Segerstad was a neighboring DSO that shared a border with Fortum.
Sjogerstads Elek. Distr.för. eko. för.	Yes	Yes	Yes	
Nossebroortens Energi eko. för.	Yes	No (26th smallest)	Yes	
Bengtsfors Energi Nät AB	Yes	Yes	Yes	
Åkab Nät & Skog AB	Yes	Yes	Yes	Changed names to Åsele Elnät AB (same concession area as earlier)
Kviinge El eko. för.	Yes	Yes	No	Acquired by Brittedals Elnät eko. för. 1 Jan 2013. Kviinge El eko för was a close neighbor but did not share a border with Brittedals Elnät eko. för.
Vallebygdens Energi eko. för	Yes	Yes	Yes	

Larvs Elektriska Distributionsförening was one of the smallest from 2003. Data is missing before 2003. Incorporated in Kvänumbygdens Energi eko. För.'s concession area from 2013. The geographical borders of the network concessions can be viewed at www.natomraden.se

Could it be that the smallest DSOs have been able to grow without engaging in mergers and acquisitions? To illustrate, we sort out the 25 smallest DSOs each year and for each year, calculate the average number of customers those 25 have had each year. It turns out that an average "small" DSO has increased by about 50% in size from 2001 to 2017, but in absolute term the increase is only 600 customers, which

must be considered a modest increase, at best. In fact, much of the increase occurred in 2017 and if that year is excluded, the annual increase is only be 25 customers per year

As the three largest DSOs have most customers than all the other DSOs combined, it is relevant to also look at their development. The three largest actually followed different trajectories 1998–2017: E.ON increased its deliveries until the mid-2000s, and has kept its total number of customers at around 1 million since then. Ellevio reduced its customers slightly until 2009 but has displayed an increasing trend since then and was up by 8% in 2017. Vattenfall slowly reduced its customer base during the first half of the sample period but increased it by the same amount in the second half, implying they had almost the same number of customers in 2017 as they did in 1998

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