Nederlandse Mededingingsautoriteit

BIJLAGE E BIJ METHODEBESLUIT

Nummer:	102106-89
Betreft zaak:	Methodebesluit X-factor en rekenvolumina regionale netbeheerders derde reguleringsperiode
Onderwerp:	Het rapport van The Brattle Group naar aanleiding van het onderzoek naar objectiveerbare regionale verschillen, Maart 2006

REGIONAL DIFFERENCES FOR GAS AND ELECTRICITY COMPANIES IN THE NETHERLANDS

MARCH 2006

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1 Executive Summary

DTe has asked us to examine certain factors that may cause regional differences in costs among gas and electricity distribution network companies. Our task is to determine whether we are capable of measuring the potential cost impact of any such factor in an objective and reliable manner. If so, we measure the costs that any such difference imposes on each company.

The companies previously agreed on the list of potential factors for review, and after extended discussion agreed on a more specific list for this study: water crossings that exceed one kilometer in length, the costs of accommodating distributed generation that is connected to the electricity distribution networks, the potential costs imposed by salty air, taxes, the costs of diverting pipes or cables in response to road works by municipalities, the need to procure energy and capacity on other networks, write-offs of bad debts by consumers, differences in load factors among companies, differences in population density, differences in the quality of soil, and connection density.

The companies agreed to co-operate in the provision of data that could enable us to analyze these factors. Over the course of several months we developed a detailed list of data requests in consultation with the companies. The companies agreed on the final data request. We asked the companies to have independent auditors review the responses to the data requests, and to provide written endorsement. Some of the auditors expressed reservations in their review of the data submitted, and in certain cases the companies did not comply with the instructions in the data requests. We discussed these problems extensively with the companies and heard various proposals: to abandon the study, to agree that the study would not prompt any revisions to the tariffs in the next control period, or to continue in various ways despite the problematic data. After extensive discussion, DTe decided that we should proceed with the study, but exclude from the analysis any data that did not receive sufficient endorsement from an independent auditor.

We have completed the analysis in accordance with the instructions from DTe. We conclude that only two factors constitute regional differences that we can measure objectively and reliably: the costs of water crossings that exceed one kilometer in length, and the local taxes paid by the companies.

Delta is the only company that has presented data on water crossings that exceed 1 kilometer in length, and that has complied with the specific data requests for these water crossings, provided the necessary supporting documentation, and secured the endorsement of an independent auditor. The costs of Delta's water crossings help explain why it has a relatively high ratio of standardised costs per composite output in comparison to the other electricity distribution companies. We find that Delta incurred on average €2.4 million per year in connection with these water crossings from 2000 through 2004, which represented approximately 3.6 % of its 2000 standardised costs. Our results include only reasonable estimates of the costs that Delta would not have incurred in connection with similar cables on land.

We have measured the precario and sufferance taxes that the electricity and gas distribution companies have paid over the past several years. Some companies do not pay taxes, but point out that they made significant payments to the relevant entities to secure exemptions from future taxes. We asked these companies to report the amounts, if any, that DTe had permitted them to capitalise in their regulatory asset bases in connection with payments made to secure exemptions from future taxes. Other companies claim to have paid for securing exemptions, but for various reasons never succeeded in capitalising the payments in their regulatory asset base. We asked these companies to estimate the taxes that they would have paid in the absence of an exemption. However, the companies in this position have reported estimates of "virtual taxes" that are implausibly high. That is why we report only the taxes actually paid and the annual capital costs associated with the payments for exemptions that were capitalised into the regulatory asset base. We also distinguish between the taxes paid to shareholders and the taxes paid to independent entities. We understand that new legislation may soon abolish the precario, in which case we would not recommend adjusting the tariffs to reflect differences in taxes. Some companies would still pay sufferance taxes after the abolition of precario, but the only information endorsed by independent auditors would suggest that sufferance taxes alone are not significant. If the precario is abolished, we would recommend no tariff adjustments for sufferance taxes either.

We have not been able to measure objectively or reliably the costs associated with other potential regional difference factors. Some of the costs are so small and vary so much over time that we have no confidence in our ability to determine whether the differences among companies reflect differences in management efficiency, simply reflect good or bad luck over the brief period examined, or reflect a significant underlying cost difference. Examples include the costs associated with consumer write-offs, the diversion of cables or pipes to accommodate road works, and the unrecovered costs of accommodating distributed generation.

We have examined statistics concerning the costs potentially imposed by salty air on overhead cables. We considered that salty air might require companies to adjust the height of towers, to install thicker insulators, to use a more expensive type of grounding, or more surge arrestors or switching bays. We have asked for statistics concerning all these factors, and have checked whether the data correlate to a network's distance from the coast. In no case do we see any basis for concluding that the networks closer to the coast incur additional expenses to avoid the problems caused by salty air. Perhaps the companies close to the coast keep salty air in mind when designing their overhead towers, but other networks that are distant from the coast end up using the same type and extent of equipment. We cannot form any conclusion concerning the impact of salty air on the average height of towers, since only two companies provided data.

Our analysis indicates that the procurement of energy and capacity is not a regional difference that could warrant adjustments to the tariffs. Some networks incur considerable expense in purchasing energy and capacity on other networks. However, management exercises discretion in deciding whether to incur these costs, or whether to expand a network sufficiently to reduce them or avoid them. Moreover, the larger networks tend to incur the same types of expenses internally. We see no basis for distinguishing between companies that incur the expenses internally, and those that incur the same expenses in the form of payments to other networks. Nor do we see any reason to presume that the larger networks, who provide high-voltage capacity to interconnected smaller networks, charge excessive amounts to the smaller networks for this capacity.

We have performed two types of analyses related to differences in load factors among the companies. Neither analysis shows any basis to adjust the tariffs. . We considered the following two issues: 1) whether companies with higher load factors tend to have lower costs, and 2) whether the composite output itself was inaccurate for electricity companies because the composite output for these companies derived from the tariff structure, which was not fully cost-reflective. Our analysis of the first issue involved calculating average load factors for each company based on the data submitted. The load factor estimates vary widely among companies in ways that are not plausible, so they cannot form any basis for recommending adjustments to tariffs. We have also assessed concerns about the composite output. Our analysis has produced a new set of (adjusted) historical composite output calculations. However, we found that the adjusted composite output does not improve the ability to predict standardised costs. Moreover, measuring the composite output in potentially different ways does not have any impact on our statistical analyses.

We looked carefully at the differences in soil quality among companies. We compiled detailed information concerning the number of connections in areas with different soil qualities. However, the data request asked the companies to provide any engineering studies retained in the ordinary course of business that assessed the higher costs of operating in poor soil areas. Not one company was able to submit such a study. The absence of such a study suggests that the costs of poor soil are not significant. The lack of any technical studies precludes any reliable engineering approach to measuring the costs of poor soil. The available data do not suffice to perform any reliable statistical analysis concerning the correlation between soil quality and costs.

We have performed statistical analyses to determine whether the relative costs of the companies depend materially on their connection density or population density. We explore multiple different statistical relationships, but the data do not permit the reliable measurement of any effect. Part of the problem is that many companies either failed to secure the endorsement of an independent auditor, or failed to comply with the data requests. Several of the low-density companies claim that international studies and engineering theory would both indicate relatively higher costs for low-density networks. However, the high-density networks point out that it may be relatively more expensive to operate in areas with high population density. The absence of any clear statistical relationship may indicate that these two factors largely offset each other.

2 Introduction

DTe asked us to perform our analysis using a two-step approach. Step 1 seeks to determine whether a regional difference could be significant on the basis of *all* the submitted data, without considering whether to exclude certain data due to the lack of an endorsement from independent auditors or for the failure to follow the instructions in the data requests. In Step 2 we look at the potentially significant regional differences, and we analyse only the data submitted in compliance with the data requests, and which received appropriate endorsement from independent auditors.[1] In the first section of this report, we discuss our methodology and present our results for Step 1 of the analysis. Later we discuss the results of Step 2.

Assessing the Significance of a Regional Difference Factor

We use two criteria to assess the significance of a regional difference factor. For a factor to be considered significant, it must meet both criteria. For some regional differences, we only present the results of one test. If a factor fails one of the tests, no further tests are needed.

The criteria are:

1. *Whether it is substantial:* Do the potential regional difference costs vary significantly among companies, when measured as a percentage of standardised costs?

   We calculate each company's reported average costs of the regional difference factor over the period 2000-3 and express them as a proportion of the company's standardised costs. Calculating average costs over the whole 2000-3 period is a way of considering the variation in costs over time. We consider both capital and operating costs.

   Before calculating the ratio of average costs to standardised costs, we adjust the companies' data for inflation. The companies reported their data in nominal terms, so we convert the nominal costs into costs in real € in 2000 prices (for electricity) and 2001 prices (for gas), to match the year of the standardised costs. To make the relevant adjustments, we use inflation data from DTe (shown in Table 1).

[1] For details on DTe's evaluation of auditor statements, see Section 4.1.

Table 1: Inflation Rates

		Inflation [A] DTe	Index (2000=1) [B] $[B]_{t-1}$x (1+[A])
2000	[1]	2.6%	1.00
2001	[2]	2.5%	1.03
2002	[3]	4.7%	1.07
2003	[4]	3.3%	1.11
2004	[5]	2.1%	1.13
2005	[6]	1.1%	1.14
2006	[7]	1.8%	1.16

Note: DTe measures inflation from August of one year to August of the following year.

We then compare each company's ratio of regional difference costs to standardised costs to the average calculated across all companies. For a regional difference to be substantial, there must be at least one company whose percentage exceeds the cross-company average by more than one percentage point.

Below we explain the primary factors that led us to choose one percentage point. We discuss these in more detail in Appendix I. Although the 1% may be criticised as arbitrary, the same criticism can be made of any cut-off level, and clearly one is necessary. In our experience no one can measure efficient costs accurately within 1%, because the boundary between management discretion and an external factor is never absolute, and because luck can affect results. In addition, our analysis seeks to determine the potential basis for adjusting tariffs prospectively. Tariff adjustments will inevitably entail inaccuracies. If we raise a company's tariffs by 1%, we cannot be sure that the resulting revenue will increase by 1%, because uncertainties exist concerning the level of customer demand. The problem with accuracy becomes more acute for potentially small tariff adjustments.

2. *Whether it is sustainable (persists over time):* Is the cost always high for some companies and always low for others, or does the relative performance of companies fluctuate over time?

   We assess sustainability on the following basis: If several of the companies over a four-year period oscillate from having lower costs than average in some years to having higher costs than average in other years, then the difference does not seem sustainable.

   If we did not impose such a criterion, we are concerned that the costs witnessed in a particular year could be due to just good luck or bad luck, which would tend to even out over time. Fluctuations in costs over time could also indicate unusual events due to cost overruns on particular projects, which would reflect the relative efficiency of different companies.

When using statistical analysis to assess the significance of a regional difference factor (e.g. connection density), we will only consider the factor to be potentially significant if we can rule out the role of luck in explaining the observed relationship between the data, using standard statistical tests such as a t-test.

Method of Analysis

We divide the regional difference factors into those that can be quantified separately and those that should be analysed together with a statistical analysis. We attempt to quantify separately the following regional differences: water crossings, distributed generation, salty air, taxes, road diversions, procurement of energy and capacity, consumer behaviour/write-offs, and adjusting the composite output for peak load. For each of these factors the companies have provided either direct cost estimates, or information relevant to engineering inputs from which we can estimate costs. The costs that we assign to any or all of these regional difference factors could be zero. We would not recognise a factor as a regional difference if we found that that factor was not substantial or sustainable, or if we did not have sufficient data to measure the effect of the factor reliably.

We propose to analyse the remaining regional difference factors (connection density, soil quality and the degree of urbanisation) using statistical analysis. We have separate data for each of these factors. However, it is difficult to isolate the impact of these regional differences on the total costs of the companies. Some of these factors, like connection density and the degree of urbanisation, could offset each other. Therefore we analyse these factors together using statistical analysis.

Statistical analysis investigates relationships between variables. We use regression analyses and correlations. A regression analysis investigates the relationship between a dependent variable such as a company's costs, and one or more independent variables such as connection density. Regression analysis produces estimates of coefficients that indicate how much the dependent variable changes for each one unit change in each of the independent variables. The analysis also involves an "error" which is a technical term describing the difference between the company's actual costs and those predicted by the regression. The term "error" does not imply any mistake in the analysis, as discrepancies between predicted relationships and actual data can depend on factors such as good or bad luck.

Statisticians use two main indicators to assess the predictive power of regression equations.

1. The R^2 value indicates the proportion of the variation in the dependent variable that is explained by the variation in the independent variable(s). The value of R^2 lies between 0% and 100%. A high R^2 indicates that the regression succeeds in explaining a lot of the variability witnessed among the independent variables.

2. The 'statistical significance' of the coefficients describes the likelihood that the perceived relationship between the independent and dependent variable could be due purely to chance.

Statisticians commonly use the “t-statistic” to evaluate ”significance” in a regression analysis. If the t-statistic of a coefficient is greater than the relevant threshold value (which statisticians call the ‘critical t-statistic’, and which can be found in any standard statistics textbook) at a 95% confidence level, you can be 95% sure that the coefficient is not equal to zero. In other words, you can be 95% sure that there really is a relationship between the dependent variable you have tested and the independent variable.

Statisticians often consider a coefficient ‘statistically significant’ if there is a 95% probability that the relationship found between the two variables is a true relationship (and therefore only 5% probability that the relationship was found by chance). While 95% is the standard, some statisticians use different figures such as 90% or 99%. The choice of significance involves judgment. We use 95% in this study. We have considered but rejected a suggestion to use 90%. The ostensible justification for 90% was to be more lenient with samples that have few observations. However, if a variable is not significant at 95%, but would be significant at 90%, then it is not plausible that we could ever measure the regional difference factor reliably. An equation that falls between the 90% and 95% thresholds by definition has a chance somewhere between 5% and 10% that the appearance of any causal relationship is just luck. If we cannot even be sure about the existence of a causal relationship, then we are still far from being able to measure the extent of any such relationship reliably.

A statistical analysis based on few observations is unlikely to produce statistically significant results. Regression equations will require more data to obtain significant results if they test multiple variables simultaneously. Statisticians call the difference between the number of observations and the number of variables the “degrees of freedom”. With only a small number of degrees of freedom, it is difficult to distinguish the results from outcomes that could have occurred by chance. Where the number of degrees of freedom is zero (i.e. there are the same number of observations as variables), the statistical analysis will produce an absurd result. The R^2 will be 100%, implying that changes in the independent variables explain all of the changes in the dependent variable. This is why it is not appropriate to derive firm conclusions from statistical analyses that have very few observations. With few degrees of freedom, regression analyses require much higher t-statistics before concluding that the results are statistically significant.

Table 2 shows how the critical t-statistics depend on the degrees of freedom. The table shows critical t-statistics for a “two-tailed” test, which refers to the two separate ends or “tails” of any distribution of probabilities. At one end of any distribution lies the possibility that the true coefficient is much higher than estimated, and at the other end is the possibility that the true coefficient is much smaller than estimated. The two-tailed test is relevant when someone is unsure whether a factor should raise or reduce standardised costs: the analyst simply wants to be sure that the true coefficient is not zero, and a positive or negative coefficient seems equally plausible. The table also shows the critical t-statistics for a “one-tailed” test. The one-tailed test is relevant when the analyst knows beforehand that the coefficient should be either positive or negative, and a non-zero coefficient of the opposite sign than expected is not a useful finding.

Table 2: Critical t-statistics and degrees of freedom

Degrees of freedom	Critical t-statistic at 95% probability	
	One-tailed test	Two-tailed test
1	6.314	12.706
2	2.920	4.303
3	2.354	3.181
4	2.132	2.777
5	2.015	2.571
6	1.943	2.447
7	1.895	2.365
8	1.860	2.306
9	1.833	2.262
10	1.812	2.228
100	1.660	1.984
∞	1.645	1.960

Where there are insufficient data points, the results of regression analyses are likely to be unreliable. The requirement for sufficient data is not a unique feature of regression analysis. No alternative statistical method can produce significant results with less data. Our study involves data from ten electricity companies and twelve gas companies. However, for many of our analyses we could not use data from all the companies. Not all companies have submitted data on every factor. In addition, some of the companies have not obtained adequate endorsement of their data from independent auditors, or have not followed the instructions in the data requests.

Our analysis of 31mm/kV insulators reflected the problems obtaining sufficient data. Only four electricity companies submitted data on the number of 31mm/kV insulators on their networks. One of the companies, Continuon, submitted separate data for two of its networks. We therefore had only five observations to perform an analysis. However, Continuon's and Eneco's data on salty air did not meet the standards for reliability, so we excluded their data from the analysis. We were left with only two observations. By definition, the correlation between two data points is 100%. Therefore, statistical analysis of these data would not produce meaningful results. We faced similar problems when attempting to test the importance of some of the other regional differences. For these reasons, we have found that, for some of the regional difference factors, it is impossible to measure their potential impact reliably.

Our proposal offered to perform a "bottom-up" analysis as a reality check on our results. The bottom-up analysis is based on the expertise of International Business Connection (IBC). IBC's core business is to advise companies on the economics of building, purchasing or expanding gas and electricity distribution companies. IBC analyses new projects from the ground up, including detailed analyses of the costs or advantages of specific geographic sites, estimates of network expansion costs and operating costs. IBC also advises distribution companies in connection with audits of their operations. IBC's work on this engagement has involved reviews of the technical data, capital and operating costs submitted by the companies for certain infrastructure (e.g. water crossings). IBC also visited the Netherlands and looked at some of the networks. IBC spoke to independent vendors of distribution equipment, and with private engineering firms that perform contracting work for distribution companies, to gain a sense of the potential range to certain cost factors. The companies shared their information with IBC on the understanding that the information would remain confidential. The companies were not willing to release the cost information to the public, because knowing the costs of particular projects is commercially sensitive. We did not need to conduct bottom-up analyses for all regional differences, because for many regional differences it was either clear that they could not be substantial, or the statistical analyses showed no significant results that required a supplementary reality check from an engineering perspective.

3 Results of Step 1 Analysis – Whether Regional Difference Factors Could be Substantial

3.1 Assessment

Below we discuss which factors we consider to be substantial and sustained regional differences. We proceed to Step 2 for those factors that we determine in Step 1 to be potentially substantial and sustained and for the factors whose potential magnitude we could not determine in Step 1.

3.1.1 Water Crossings

Methodology

We only consider water crossings that are at least 1km long. A distance cut-off was necessary, because the inclusion of extremely short water-crossings would imply the inclusion of any cables crossing canals. The companies agreed that crossing canals is not inherently more expensive than addressing other obstacles that ordinarily present themselves. We discussed the possibility of including all water-crossings that required horizontal drilling, but several companies explained that they also have to conduct horizontal drilling in various circumstances even in the absence of water-crossings. We therefore agreed that a threshold of one kilometre would focus on those water-crossings that entailed significantly higher costs than companies tend to face in other circumstances. Only three electricity companies and one gas company submitted data on water crossings over 1km long.

Total Costs of Water Crossings

The companies reported capital costs and maintenance costs. We estimate the total costs using the equation below:

Depreciation + return on capital + maintenance costs + rental payments – revenue from sharing the water crossing.

Table 3 and Table 4 show the results.

For electricity, Delta reports total costs of water crossings that are, on average, 4.2% of its standardised costs. For the other two companies (Continuon and Eneco) the reported costs are much less than 1% of standardised costs. The average across all companies is small, and so Delta's water crossings clearly meet the criterion for a potentially substantial regional difference. The water crossings costs are also sustained. Delta's costs are reasonably stable over time: 3.7-5.1% of standardised costs between 2000 and 2003. Eneco was the only gas company to submit data. Eneco's costs are not substantial.

Table 3: Total Costs of Water Crossings (electricity)

	Total costs per standardised cost				
	2000	2001	2002	2003	Average
DELTA Netwerkbedrijf B.V.	4.3%	5.1%	3.7%	3.8%	4.2%
Eneco Netbeheer B.V.	0.004%	0.004%	0.004%	0.004%	0.004%
Total Essent Group	-	-	-	-	0%
Netbeheerder Centraal Overijssel B.V.	-	-	-	-	0%
NRE Netwerk B.V.	-	-	-	-	0%
NV Continuon Netbeheer	0.2%	0.2%	0.2%	0.2%	0.2%
ONS Netbeheer B.V.	-	-	-	-	0%
RENDO Netbeheer B.V.	-	-	-	-	0%
Tennet B.V	-	-	-	-	0%
Westland Energie Infrastructuur B.V.	-	-	-	-	0%
Average	0.4%	0.5%	0.4%	0.4%	0.4%

Table 4: Total Costs of Water Crossings (gas)

	Total costs per standardised cost				
	2000	2001	2002	2003	Average
B.V. Netbeheer Haarlemmermeer	-	-	-	-	-
DELTA Netwerkbedrijf B.V.	-	-	-	-	-
Eneco Netbeheer B.V.	0.1%	0.1%	0.1%	0.2%	0.1%
Total Essent Group	-	-	-	-	-
Intergas Netbeheer B.V.	-	-	-	-	-
Netbeheerder Centraal Overijssel B.V.	-	-	-	-	-
NRE Netwerk B.V.	-	-	-	-	-
NV Continuon Netbeheer	-	-	-	-	-
Obragas Net N.V.	-	-	-	-	-
ONS Netbeheer B.V.	-	-	-	-	-
RENDO Netbeheer B.V.	-	-	-	-	-
Westland Energie Infrastructuur B.V.	-	-	-	-	-
Average	0.01%	0.01%	0.01%	0.02%	0.01%

We conclude that water crossings may be a significant regional difference for electricity distribution but not for gas. In Step 2 we discuss the reliability of the electricity companies' data, we attempt to quantify the incremental costs of water crossings, and we consider whether the water crossings could still be a substantial regional difference after estimating their incremental costs relative to comparable land lines.

3.1.2 Distributed Generation

Methodology

We calculate the companies' unrecovered distributed generation costs as a proportion of the companies' respective standardised costs. Since the costs of connecting generating units and of upgrading the network are capital costs, we estimate an annual equivalent cost for them. To calculate the unrecovered capital costs we first add the costs of connecting generating units and of upgrading the network, and subtract the compensation received for connecting units. We assume that the book value at the start of 2000 is zero, since we asked for distributed generation added after January 1, 2000. We calculate a return on capital and depreciation on capital expenditures. Our depreciation calculations assume a lifespan of forty years. Note that all distributed generation installations were constructed after 2000 and so count as "new" investments (to which the depreciation lives in the RAR apply). For investments that are made in a particular year, we assume that they are made in the middle of the year on average, and therefore receive 50% of the annual depreciation and annual return by the end of the year. We calculate the annual return as the WACC multiplied by the start-of-year book value. We then calculate each company's total unrecovered distributed generation costs in each year using the following formula:

Capital costs of connecting generating units and upgrading the network + cost of maintaining connections + ongoing operating costs – compensation received for maintenance

Finally, we express unrecovered costs in 2000 € for electricity and 2001 € for gas, and compare them to the companies' respective standardised costs.

Results

Only two companies provided information on distributed generation costs: Delta and Continuon. Neither company's unrecovered costs are substantial. We therefore conclude that distributed generation costs are not a regional difference.

Table 5: Distributed Generation Costs

	Unrecovered Deep Costs as % Standardised Costs				
	2000	2001	2002	2003	Average
DELTA Netwerkbedrijf B.V.	0.1%	0.2%	0.2%	0.2%	0.2%
Eneco Netbeheer B.V.					
Total Essent Group					
Netbeheerder Centraal Overijssel B.V.					
NRE Netwerk B.V.					
NV Continuon Netbeheer	0.0%	0.1%	0.1%	0.2%	0.1%
ONS Netbeheer B.V.					
RENDO Netbeheer B.V.					
Tennet B.V					
Westland Energie Infrastructuur B.V.					

3.1.3 Salty Air

Salty air issues are only relevant in the case of overhead cables. The data indicate that overhead cables represent a very small fraction of each network's total length. Apart from TenneT, whose distribution network operates only at relatively high voltage levels, the largest fraction is 4%, for Delta (see Table 6). Nevertheless, we cannot assess the potential significance of salty air until we perform some statistical analyses in Step 2.

Table 6: Proportion of Overhead Cables

	All voltages
	2003
DELTA Netwerkbedrijf B.V.	4%
Eneco Netbeheer B.V.	2%
Total Essent Group	2%
Netbeheerder Centraal Overijssel B.V.	
NRE Netwerk B.V.	0%
NV Continuon Netbeheer	2%
ONS Netbeheer B.V.	0%
RENDO Netbeheer B.V.	0%
Tennet B.V	55%
Westland Energie Infrastructuur B.V.	0%

3.1.4 Taxes

Taxes vary significantly among companies and in some cases can comprise over 18% of the total standardised costs. The differences seem to persist: a company with high taxes in one year will also tend to have high taxes in other years. Taxes are a potential regional difference. Therefore, we shall consider the issue of taxes in Step 2. In Step 2 we consider the ability to quantify taxes objectively, including the issues of virtual taxes and the taxes paid to entities that are shareholders of the distribution companies. There is no need to analyse the taxes in further detail at this stage, since we have already concluded that taxes are a potential regional difference that must be considered in Step 2.

3.1.5 Road Diversions

Methodology

We assess whether the costs of road diversions are substantial by calculating each company's unrecovered diversion costs. We define unrecovered costs as the total costs reported minus the compensation received from the entities such as municipal governments requesting the road diversion activity. We convert the nominal unrecovered costs in each year to 2000 prices in the case of electricity and 2001 prices in the case of gas. We then compare the 2000-3 average unrecovered costs to the companies' respective standardised costs.

Results

Electricity

The unrecovered costs of road diversions are small. For all companies, the 2000-3 average unrecovered costs as a proportion of standardised costs differ by less than one percentage point from the cross-company average. Table 7 shows the averages for each company. CONET is close to being substantial, but in any case CONET's costs are not sustained. In addition, CONET reported average unrecovered costs equal to almost 1.5% of its 2000 standardised costs, but the reported average depends heavily on an outlier in 2000. In 2000, CONET reported an unrecovered cost per standardised cost that was ten times higher than the average for the other companies. In other years, CONET reported average unrecovered road diversion costs equal to only 0.7% of its 2000 standardised costs.

Table 7: Average Unrecovered Costs for Electricity

	2000	2001	2002	2003	Average
DELTA Netwerkbedrijf B.V.	0.38%	0.06%	0.48%	0.35%	0.32%
Eneco Netbeheer B.V.	0.92%	0.54%	0.65%	0.77%	0.72%
Total Essent Group	0.68%	0.31%	0.56%	0.22%	0.44%
Netbeheerder Centraal Overijssel B.V.	3.72%	0.46%	1.10%	0.53%	1.45%
NRE Netwerk B.V.					
NV Continuon Netbeheer	0.00%	1.36%	0.63%	0.54%	0.84%
ONS Netbeheer B.V.	0.00%	0.00%	0.00%	0.00%	0.00%
RENDO Netbeheer B.V.	0.37%	0.00%	0.95%	1.38%	0.68%
Tennet B.V	0.00%	0.00%	0.00%	0.00%	0.00%
Westland Energie Infrastructuur B.V.	0.13%	0.17%	0.23%	0.16%	0.17%
Company average	0.69%	0.32%	0.51%	0.44%	0.51%

Notes: NRE could not provide the data in the correct format.
ONS and Tennet did not have to divert any cables during the period 2000-3.

Several networks witnessed significant variation in the costs of road diversions over time. The four-year average across all companies was 0.51%. Several of the companies had costs that in a particular year either matched the average or that oscillated from below to above the average within the 2000-3 period. The results of correlation analysis indicate that the costs of road diversions do not appear to be closely related to population density. For example, Rendo has one of the lowest population densities in the sample, but has a higher percentage of road diversion costs than the average. Essent has similar connection density to Rendo, but has incurred less road diversion costs than the average. Together Essent's 0.44% and Rendo's 0.68% average out to 0.56%, which is close to the average of the entire sample. Something other than population density, perhaps just random factors, must explain the difference between Essent and Rendo. If the companies with two of the lowest population densities on average match the rest of the sample, there does not appear to be any basis for concluding that population density could be an important factor. The original reason for examining road diversions was in response to concerns by networks in densely populated areas, who thought that they might experience relatively higher costs related to road maintenance and construction activities.

Gas

Three companies have not been able to provide diversions data in the correct form: Haarlemmermeer, NRE and Obragas. For the companies that did provide data in the correct form, the average unrecovered costs during 2000-3 are for each company no more than 1.2% of the standardised costs, and the average across all companies is 0.6% of standardised costs (see Table 8). No company meets the criterion for a substantial regional difference. We also note considerable variation among the results for the companies in particular years. Of the nine companies providing appropriate data, four have costs which either match the average in a particular year or oscillate from below to above the average within the 2000-3 period. The four companies are Delta, CONET, Continuon, and Westland.

Table 8: Average Road Diversion Costs for Gas Networks

	2000	2001	2002	2003	Average
B.V. Netbeheer Haarlemmermeer					
DELTA Netwerkbedrijf B.V.	0.8%	0.1%	0.1%	0.5%	0.4%
Eneco Netbeheer B.V.	0.5%	0.5%	0.2%	0.1%	0.3%
Total Essent Group	1.0%	0.8%	1.1%	1.2%	1.0%
Intergas Netbeheer B.V.	0.5%	0.3%	0.1%	0.4%	0.3%
Netbeheerder Centraal Overijssel B.V.	3.3%	0.6%	0.5%	0.3%	1.2%
NRE Netwerk B.V.					
NV Continuon Netbeheer	0.0%	2.5%	1.2%	0.0%	1.2%
Obragas Net N.V.					
ONS Netbeheer B.V.	0.0%	0.0%	0.0%	0.0%	0.0%
RENDO Netbeheer B.V.	0.1%	0.1%	0.3%	0.5%	0.2%
Westland Energie Infrastructuur B.V.	0.1%	0.0%	2.1%	0.6%	0.7%
Company average	0.7%	0.5%	0.6%	0.4%	0.6%

Note: Haarlemmermeer, Obragas and NRE are excluded because they could not provide the data in the correct format. ONS did not have to divert any pipes during the period 2000-3.

Conclusion

Based on the available data, we conclude that the costs associated with road diversions are not a significant or sustained regional difference for either gas or electricity distribution companies.

3.1.6 Procurement of Energy and Capacity

We take this factor to refer to the following costs:

a) Procurement costs to handle transport limitations; and

b) Cost of procuring high-voltage transmission capacity.

We believe that the role of management discretion should prevent this factor from becoming a regional difference that should prompt adjustments to the tariffs. The regulatory framework provides companies with incentives to reduce their costs, and one way in which companies can reduce their costs is by under-investing in the network. However, such under-investment is likely to raise the costs of constraints. Including the costs of constraints as a regional difference would therefore tend to reward companies that under-invested in the network. The rewards could provide perverse incentives to under-invest.

We also fear that perverse results would arise if we treated the costs of procuring capacity as a regional difference. Imagine a small company that depends on a large company for capacity at the high voltage level. The large company would never want to expand its high-voltage network to accommodate growth in demand from the small company. Although the large company could charge a cost-reflective tariff for the use of the added capacity, the large company would reasonably anticipate that for every Euro received in tariff payments, the smaller company would end up reporting an extra Euro as a regional difference, which would make the smaller company look like in reality it was more efficient relative to the large company.

However, some of the companies have requested that we analyse the costs associated with the procurement of energy and capacity. In Step 2 we discuss several data issues that make it impossible to measure reliably the potential impact of this regional difference.

3.1.7 Consumer Behaviour/Write-Offs

Methodology

We had hoped to test consumer behaviour by comparing write-offs for different types of consumers. If high write-offs were an urban phenomenon, they would concentrate on residential customers. However, only two companies broke down write-offs by consumer type, and only for 2003. It is not possible to draw conclusions from such data.

We have, however, analysed aggregate write-offs across all consumer types. To determine whether write-off costs are substantial, we calculate total write-off costs as a proportion of companies' standardised costs. We assess whether the percentages vary significantly between the companies.

We calculate write-offs using the following equation:

Write-off costs = actual write-offs + cost of debt collecting + cost of preventing non-payment + fees paid for outsourcing

Results

<u>Gas</u>

We focus on the write-offs reported in the cash-flow statements. The cash-flow write-offs should reflect the increase in reported revenue from year to year that has not been collected. The write-offs reported on income statements are more susceptible to the optimism or pessimism of companies concerning the collection of their receivables. The variability of Essent's income-statement data confirm our preference to look at cash-flow write-offs. It does not seem reasonable that Essent's income statement write-offs in 2000 are 360 times the level of its actual write-offs, and less than six times the level of actual write-offs in 2003.

In the case of gas, for all companies except one (Continuon), the 2000-3 average of write-off costs as a proportion of standardised costs is below 1.7%. Continuon only provides data for 2003. In this year, Continuon's reported write-off costs were over 11% of Continuon's standardised costs. If we assume that in the other years the write-offs were zero, Continuon's 2000-3 average ratio of write-off costs to standardised costs is 2.8%.

We consider the reasonableness of Continuon's 11% write-offs in 2003 here in Step 1. If we proceeded to Step 2, we would not even look at Continuon's data, because Continuon has not received an adequate auditor endorsement for its write-offs. We consider the data here despite its lack of endorsement, because the exclusion of Continuon's data is material to the conclusion that average write-offs cannot be a substantial regional difference. For all companies excluding Continuon, average write-off costs for the companies during 2000-3 are only 0.8% of standardised costs. No other company's percentage differs from the average by more than one percentage point.

We see no reason why Continuon's write-offs in 2003 should be so large in absolute terms, and so much larger than those of the other companies. In theory, Continuon might only write-off bad debt periodically, so the 2003 write-offs might be unrecovered revenue that Continuon had reported as income several years earlier. However, this type of problem should not affect cash-flow write-offs. Recall that cash-flow write-offs reflect the change in provisions for uncollected amounts from year to year. If more revenues are booked but not collected in a particular year than in the preceding year, Continuon should be showing cash-flow write-offs even if Continuon remains optimistic about eventually collecting old debts. Moreover, it is not standard practice to report revenue as income and to leave it on the books for several years in the absence of collections from customers. Furthermore, if companies re-evaluate their accounts receivables only once every few years, then it would not be responsible for us to derive conclusions from data submitted from 2000 to 2003. For example, if we understand Continuon's write-offs of 11% in 2003 as a way of cleaning up old accounts from previous years, we have no way of knowing whether that the 11% covered four, five or six preceding years. If the 11% in 2003 covered more than four years, then it would be clearly unreasonable to include the full 11% in the four-year average. Continuon has had the opportunity to respond to our concerns and to explain its data.

However, Continuon has not provided any explanation. We therefore see no basis for using Continuon's data.[2] The data from the other companies do not meet the threshold for significance.

Table 9: Write Offs (Gas)

	2000-3 average cost/SC	Deviation from Average
B.V. Netbeheer Haarlemmermeer	0.5%	-0.3%
DELTA Netwerkbedrijf B.V.	0.8%	0.0%
Eneco Netbeheer B.V.	0.0%	-0.8%
Total Essent Group	1.4%	0.6%
Intergas Netbeheer B.V.	1.1%	0.3%
Netbeheerder Centraal Overijssel B.V.	0.3%	-0.5%
NRE Netwerk B.V.	1.2%	0.4%
NV Continuon Netbeheer	2.8%	
Obragas Net N.V.	1.4%	0.6%
ONS Netbeheer B.V.	0.2%	-0.6%
RENDO Netbeheer B.V.	0.3%	-0.5%
Westland Energie Infrastructuur B.V.	1.6%	0.8%
Company Average (excl. Continuon)	0.8%	0.0%

Sources and Notes:

Based on total write-off costs (using actual write-offs) calculated from data in companies' submissions and adjusted for inflation.
Continuon's auditor stated that Continuon was only able to supply data for 2003. We assume that Continuon's write-offs in previous years were zero.
ONS and CONET did not supply data for 2000. We assume that write-offs in 2000 were zero.

Electricity

We consider the cash-flow write-offs for the electricity distribution companies as we did for gas. We see considerable variability in Essent's income statement write-offs, which confirms our preference to consider cash-flow write-offs. Essent's income statement write-offs were 475 times the level of Essent's actual write-offs in 2000.

For electricity, write-off costs comprise around 0.5% of standardised costs on average for all companies excluding Continuon. Again, Continuon reports an implausible ratio of 7.2% for 2003 alone, with no information given for any of the preceding years. We reject this data for the same reasons that we rejected Continuon's 11% figure in our analysis of the gas companies.

[2] In any case, as Table 16 and Table 17 show, DTe's auditor finds Continuon's data on write-offs to be unreliable.

Essent's percentage is just on the borderline of being substantial. We therefore consider write-offs for electricity companies to be a potentially substantial regional difference.

Table 10: Write-Offs (Electricity)

	2000-3 average cost/SC	Difference from average
DELTA Netwerkbedrijf B.V.	0.32%	-0.21%
Eneco Netbeheer B.V.	0.00%	-0.53%
Total Essent Group	1.56%	1.03%
Netbeheerder Centraal Overijssel B.V.	0.75%	0.22%
NRE Netwerk B.V.	0.63%	0.10%
NV Continuon Netbeheer	1.81%	
ONS Netbeheer B.V.	0.37%	-0.16%
RENDO Netbeheer B.V.	0.17%	-0.36%
Tennet B.V	0.00%	-0.53%
Westland Energie Infrastructuur B.V.	0.98%	0.44%
Company Average (excl. Continuon)	0.53%	0.00%

Based on total write-off costs (using actual write-offs) calculated from data in companies' submissions and adjusted for inflation. Continuon was only able to supply data for 2003. We assume that Continuon's write-offs in previous years were zero.

Conclusion

We find Continuon's write-offs implausible. Continuon has only been able to present data for one year, and the figures are too high to be plausible. Apart from Continuon, no company reported average write-offs that exceeded the cross-company average by more than one percentage point, except the electricity company, Essent, which is right on the borderline of meeting the criterion for a substantial regional difference.

Since Essent's number is potentially substantial, we proceed to Step 2.

3.1.8 Peak Load

The companies have raised two issues in relation to peak load. One issue is whether companies with higher load factors tend to have lower costs. The peak load of a company will affect its composite output, but some of the companies were evidently concerned that measuring efficiency with respect to composite output was not enough. Perhaps having a high load factor could explain why some of the companies were perceived to be more efficient. Since the companies do not control the load factors of their consumers, and the load factors vary among companies, peak load was a potential regional difference. Another related concern was that the composite output itself was inaccurate for electricity companies, because the composite output for these companies derived from the tariff structure, which was not fully cost-reflective. The costs of serving residential customers depend largely on their maximum peak load, but the tariff structure did not include any fixed component per KW for these customers. Our report explores both issues with respect to peak load.

The original composite output is arguably inaccurate for the <3 x 25 A tariff categories, because these categories did not include a tariff component based on the peak load (kW). Instead, the categories just include a fixed tariff per month and one or two volume-dependent tariffs. The costs of serving customers who use these tariffs will be based also on the peak load, as sufficient capacity will have to be built to accommodate the peak load. From a theoretical perspective we therefore consider it appropriate to adjust the composite output. We adjust the composite output assuming that the <3 x 25 A tariff categories have a kW-tariff. In order to re-calculate the composite output we need to know the following for the new kW-tariff: i) what the average fixed-per-kW component would be across the whole sector, and ii) how much each company would have recovered from its fixed-per-KW component in 2000.

To estimate the revenues from the fixed-per-kW component, we assume that the amount of capacity contracted is equal to 4kW multiplied by the number of customers. EnergieNed provided the information on which we based this assumption. In our experience a figure of this magnitude seems reasonable. If for example a company had 1,000 customers attached to its network at the <3 x 25 A level, the capacity contracted by these consumers is assumed to be 4,000 kW.

The average tariff is calculated as the total revenues divided by the total kW. We assume that for each of the two 3 x 25 A categories - Afnemers < 3 x 25 A (DT) and Afnemers < 3 x 25 A (ET) – the revenues would remain the same after reforming the tariff to include a fixed-per-kW component. We split the revenues between the fixed-per-kW component and the other tariff components using a 16%:84% ratio in accordance with the electricity tariff code. For example if the revenues for the kWh-tariff(s) were originally €100, the kW-tariff would recover €16 and the other components would now recover €84.

Table 11 shows the differences between the unadjusted and adjusted values for composite output. These range between -0.4% (for Essent and NRE) and +2.6% (for ONS). The adjustment is substantial for ONS, but not for the other companies. The adjustment for ONS is over two percentage points above the cross-company average. For all other companies the adjustment differs by less than one percentage point from the cross-company average. Because the adjustment could have a significant effect on ONS, we believe that it could be substantial. We investigate this issue further in Step 2.

Table 11: Adjustments to Composite Output

	Unadjusted Composite Output 2000 (€) [A] Dte	Adjusted Composite Output 2000 (€) [B] Brattle calculations	Adjustment (€) [C] [B]-[A]	Adjustment (%) [C] [C]/[A]
DELTA Netwerkbedrijf B.V.	54,806,807	54,977,289	170,482	0.3%
Eneco Netbeheer B.V.	451,280,474	454,821,105	3,540,632	0.8%
Total Essent group	672,071,375	669,292,968	-2,778,407	-0.4%
Netbeheerder Centraal Overijssel B.V.	11,551,380	11,575,520	24,139	0.2%
NRE Netwerk B.V.	23,901,258	23,815,685	-85,573	-0.4%
NV Continuon Netbeheer	642,714,194	641,557,832	-1,156,362	-0.2%
ONS Netbeheer B.V.	7,326,702	7,514,306	187,604	2.6%
RENDO Netbeheer B.V.	7,055,436	7,089,921	34,485	0.5%
Tennet B.V	53,151,731	53,151,731	0	0.0%
Westland Energie Infrastructuur B.V.	22,887,597	22,950,598	63,000	0.3%
Average				0.4%

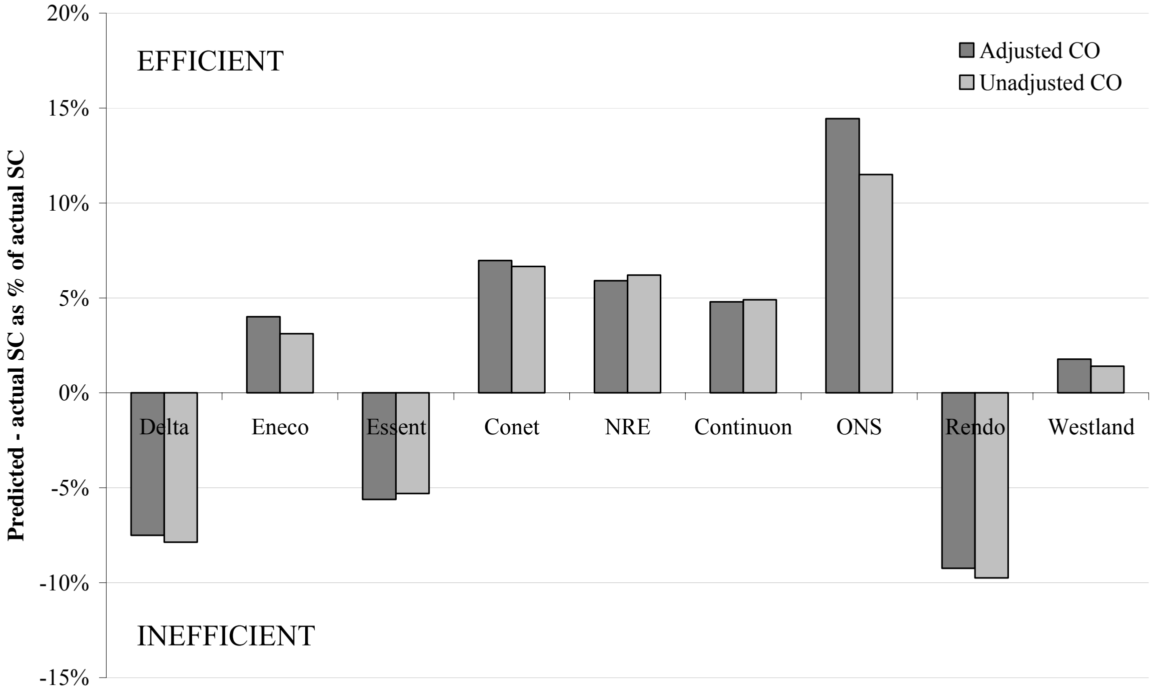
We also investigate whether the adjustment improves the relationship between costs and composite output. Adjusting the composite output could in theory be important for understanding other regional differences. If we perform statistical analyses trying to predict the relationship between connection density and costs per composite output, we want to measure composite output accurately. The same principle applies to any regional difference that we try to assess through statistical analysis. To evaluate the potential impact of measuring the composite output in different ways, we perform two regressions:

Standardised costs = β(unadjusted composite output) and

Standardised costs = β(adjusted composite output)

We do not include constants in the regression since the efficiency benchmarks in the current regulatory period assumed standardised costs to be directly proportional to composite output. We exclude TenneT from the analysis since TenneT does not have any customers in the relevant tariff categories where we might measure the composite output differently. Using the regression results, we calculate the standardised costs predicted by unadjusted composite output and by adjusted composite output. We compare the percentage errors between predicted and actual standardised costs in each case. Figure 1 shows the errors in each regression.

Figure 1: Errors in Composite Output Regressions



Adjusting the composite output does not improve the relationship between composite output and standardised costs. The R^2 in a regression with standardised costs is slightly lower when the adjusted composite output is used. However, the composite output adjustment has a material impact on ONS. We therefore discuss the composite output issue further in Step 2.

Regardless of the way in which we calculate composite output, a separate question is whether composite output succeeds in capturing the true cost differences reflected by the differing load factors of the companies. Perhaps the companies with the highest load factors have an inherent efficiency advantage that was not captured fully by the relationship between costs and composite output. We would expect such an effect to persist. There is no way to test whether variations in load factors could be a substantial regional difference, unless we first perform statistical analyses determining their potential impact on costs. We perform such analyses in Step 2.

3.1.9 Degree of Urbanisation/Population Density

We have heard many different reasons why urban networks might have higher costs. We consider some possible reasons separately, such as write-offs. However, other questions are difficult to analyse separately, such as those associated with the cost of labour. We have committed to attempt some statistical analysis investigating whether population density could help explain costs. We cannot form any opinion about the substantial or insubstantial nature of the regional difference without performing such analyses. We therefore consider the issue in Step 2.

3.1.10 Type/Quality of Soil

Methodology

We look at the proportion of companies' connections that are in "poor" soil areas. In our analysis, we include connections in all the postcode areas listed in the data request.[3] We only consider the companies for whom we have data on the total number of connections in all soil areas at the time the number of connections in poor soil was measured. It would not be appropriate to calculate proportions of connections in poor soil areas if the number of connections in poor soil areas and the total number of connections were measured at different times. If we mix information from different years we get some strange results. 105% of ONS's total connections would appear to be in shrinking soil and an additional 21% in peat soil, for a total 126% of total connections.

Results

The proportion of connections in poor soil areas varies significantly between companies. For electricity, 6-75% of connections lie in peat soil areas and 0-3% in shrinking soil areas. For gas, 6-88% of connections lie in peat soil areas and 0-1% in shrinking soil areas. This variation indicates that soil quality is a potential regional difference. To assess whether it is a substantial regional difference, we must quantify the costs associated with poor soil. In Step 2 we evaluate the feasibility of quantifying the costs associated with poor soil.

Table 12: Connections in Poor Soil – Electricity

	Connections in peat soil as % total	Connections in shrinking soil as % total
DELTA Netwerkbedrijf B.V.	6%	0%
Eneco Netbeheer B.V.	n/a	n/a
Total Essent Group	n/a	n/a
Netbeheerder Centraal Overijssel B.V.	55%	0%
NRE Netwerk B.V.	n/a	n/a
NV Continuon Netbeheer	36%	3%
ONS Netbeheer B.V.	n/a	n/a
RENDO Netbeheer B.V.	75%	0%
Tennet B.V	n/a	n/a
Westland Energie Infrastructuur B.V.	n/a	n/a

Note: n/a indicates that no information was provided on the number of connections in bad soil or that no information was provided on the total number of connections (measured at the same time as the number of connections in bad soil was measured).

[3] The data request contained a list of all postcode areas that we believed contained some peat soil and/or shrinking soil, even if such soil accounted for only a small proportion of the total area.

Table 13: Connections in Poor Soil – Gas

	Connections in peat soil as % of total	Connections in shrinking soil as % of total
B.V. Netbeheer Haarlemmermeer	n/a	n/a
DELTA Netwerkbedrijf B.V.	6%	0%
Eneco Netbeheer B.V.	n/a	n/a
Total Essent Group	n/a	n/a
Intergas Netbeheer B.V.	n/a	n/a
Netbeheerder Centraal Overijssel B.V.	74%	0%
NRE Netwerk B.V.	n/a	n/a
NV Continuon Netbeheer	33%	1%
Obragas Net N.V.	51%	0%
ONS Netbeheer B.V.	n/a	n/a
RENDO Netbeheer B.V.	88%	0%
Westland Energie Infrastructuur B.V.	n/a	n/a

Note: n/a indicates that no information was provided on the number of connections in bad soil or that no information was provided on the total number of connections (measured at the same time as the number of connections in bad soil was measured).

3.1.11 Connection Density

As Table 14 shows, connection density varies substantially among companies. Step 2 is necessary to assess the potential costs associated with these variations, and the reliability of the data.

Table 14: Connection Density (electricity)

	Connections/km network length	Connections/km2 surface area
DELTA Netwerkbedrijf B.V.	28	141
Eneco Netbeheer B.V.	48	566
Total Essent Group	22	137
Netbeheerder Centraal Overijssel B.V.	37	778
NRE Netwerk B.V.	69	1,610
NV Continuon Netbeheer	37	258
ONS Netbeheer B.V.	61	1,924
RENDO Netbeheer B.V.	29	141
Westland Energie Infrastructuur B.V.	28	369
Ratio of maximum to minimum	3	14

Notes and Sources:

For all companies except CONET, we use circuit length to represent network length. CONET did not supply data on its circuit length, and so we use CONET's route length.
Surface area is land area plus inland water (based on CBS data).
We exclude Tennet because we do not consider it comparable to other companies for the analysis of connection density.

Table 15: Connection Density (gas)

	Connections/km network length	Connections/km2 surface area
B.V. Netbeheer Haarlemmermeer	66	284
DELTA Netwerkbedrijf B.V.	39	92
Eneco Netbeheer B.V.	76	332
Total Essent Group	48	137
Intergas Netbeheer B.V.	46	113
Netbeheerder Centraal Overijssel B.V.	31	104
NRE Netwerk B.V.	60	230
NV Continuon Netbeheer	59	206
Obragas Net N.V.	46	137
ONS Netbeheer B.V.	150	1,706
RENDO Netbeheer B.V.	27	70
Westland Energie Infrastructuur B.V.	49	339
Ratio of maximum to minimum	5	24

For surface area, we use the data the companies provided on area of land + inland water. Since Intergas only provided information on its land area, we assume the area of its land + inland water is equal to its land area.

3.2 Conclusions

The analysis we have performed so far suggests that the following are potentially significant regional differences:

a) Water crossings (electricity companies only)

b) Taxes

c) Consumer behaviour/write-offs for electricity companies.

d) Peak load (whether the composite output itself was inaccurate for electricity companies)

e) Type/quality of soil

We find that distributed generation, road diversions and consumer behaviour/write-offs for gas companies are not significant regional differences. In our view, procurement of energy and capacity is also not a regional difference, because it is an issue related to management discretion. However, at the request of some companies, in Step 2 we analyse the data on procurement of energy and capacity.

We have not yet been able to evaluate the magnitude of four factors, because they rely on statistical analyses that belong in Step 2:

a) Salty air

b) Peak load (whether companies with higher load factors tend to have lower costs)

c) Population density

d) Connection density

4 Results of Step 2 Analysis –Data Assessment

In Step 1, we assessed the magnitude of potential regional differences. In this section we consider the potentially substantial ones, or the ones that required statistical analyses to determine whether they could be substantial. We limit statistical analyses to the data that independent auditors have endorsed and that comply with the instructions in the data request. We conclude that, given the available data, we see only two regional differences that we can determine reliably: water crossings and taxes. While there may be a relationship between connection density and costs, we do not recommend any adjustment to the tariffs because we do not see any opportunity to measure the relationship reliably. The poor quality of the data prevents us from concluding that some of the other potential factors are regional differences. Even with the taxes we have very poor information. Several companies provided information on taxes that did not comply with the data requests, or that their auditors failed to endorse. Our analysis shows significant taxes for Delta, which was originally perceived to be one of the least efficient companies—perhaps high taxes explained part of this perception.

We have performed some analyses using the composite output as originally reported, and other analyses in which we recalculated the composite output by imputing a fixed-per-kW tariff component to the companies in the year 2000. However, this does not mean that we recommend indexing future tariffs to account for any deficiencies for the historical way of calculating the composite output in the year 2000. We make no specific recommendations for adjusting the tariffs.

4.1 Reliability

Table 16 and Table 17 show the results of an assessment by DTe's auditor. We identified the regional differences that relied on data of either a financial or technical nature from the companies. We asked DTe's auditor to review the opinions given by the independent auditors to the company.

DTe's auditor assessed the data's reliability with respect to the following criteria: For financial data to be considered reliable, the company's independent auditor must have endorsed the data without qualification ("goedkeurende accountantsverklaring"). DTe's auditor told us whether the independent auditors of the companies had provided unqualified endorsements. DTe's auditor also indicated where the data failed to comply with relevant instructions in the data requests, or did not correspond to specific dates. For technical information, DTe's auditor told us whether the auditor had stated that the data were consistent with the companies' administrative systems. The technical data did not need to have an unqualified audit statement. For simplicity, the tables below use the term "not reliable" with respect to these issues.

We do not consider in our analysis the data labelled as "not reliable" in the tables. This does not prevent us from rejecting specific information as unreasonable or not credible for other technical or economic reasons.

Table 16: Reliability of Data: Electricity

	Financial Data					
	Actual taxes	**Virtual taxes**	**Water Crossings**	**Transport Limitations**	**High-voltage costs**	**Write-Offs**
	Table 2.8	Table 2.8	Table 2.5	Table 2.7	Table 2.11	Table 2.12
DELTA Netwerkbedrijf B.V.	(1)	(1)	(3)	(1)	(1)	(7)
Eneco Netbeheer B.V.	(1)	**not reliable (5)**	**not reliable (5)**	(1)	(1)	**not reliable (5)**
Total Essent Group	(1)	(1)	n/a	no data	(1)	**not reliable (5)**
Netbeheerder Centraal Overijssel B.V.	(1)	(1)	n/a	(1)	(1)	(1)
NRE Netwerk B.V.	no data	no data	n/a	(1)	(1)	(1)
NV Continuon Netbeheer	**not reliable (6)**	**not reliable (6)**	**not reliable (6)**	(1)*	(1)*	**not reliable (5)**
ONS Netbeheer B.V.	(1)	(1)	n/a	no data	(1)	**not reliable (5)**
RENDO Netbeheer B.V.	(1)	(1)	n/a	(1)	(1)	(1)
Westland Energie Infrastructuur B.V.	(1)	(1)	n/a	(1)	(1)	(1)
Tennet B.V	(1)	(1)	n/a	(1)	(1)	no data

	Technical Data					
	Water Crossings	**Network length**	**No. of connections**	**Salty Air**	**Soil Quality**	**Peak Load & Annual Volumes**
	Table 2.5	Table 2.2	Table 2.2	Table 2.7	Table 2.4	Table 2.10
DELTA Netwerkbedrijf B.V.	(1)	(2)	(2)	(1)	(2)	(1)
Eneco Netbeheer B.V.	**not reliable (5)**	**not reliable (4)**	(1)	**not reliable (5)**	n/a	**not reliable (4)**
Total Essent Group	no data	**not reliable (5)**	(2)	(2)	(2)	(1)
Netbeheerder Centraal Overijssel B.V.	no data	(1)	(1)	(1)	(1)	(1)
NRE Netwerk B.V.	no data	(2)	(2)	(1)	(1)	n/a
NV Continuon Netbeheer	(2)	**not reliable (5)**	(1)	**not reliable (5)**	(2)	**not reliable (4)**
ONS Netbeheer B.V.	no data	(1)	(1)	no data	(1)	(1)
RENDO Netbeheer B.V.	no data	(1)	(1)	(1)	(1)	(1)
Westland Energie Infrastructuur B.V.	no data	(1)	(1)	(1)	(1)	(1)
Tennet B.V	no data	(1)	(1)	(1)	(1)	(1)

(1) based on unqualified audit opinion (relating to this table)
(2) disclosed data reconcile to accounting system
(3) based on audit opinion and additional information from network company
(4) original data (which reconcile to accounting systems) have been recalculated by the network company on experience values
(5) use of estimated values and/or experience values and/or incorrect use of definitions audit instruction
(6) disclosed bookvalue is based on specific valuation report, not on historical cost (as required in audit instruction)
(7) based on unqualified audit opinion (relating to this table, version 2 Sep-05)
* relates only to 2002 and 2003.

Table 17: Reliability of Data: Gas

	Financial Data				Technical Data			
	Actual Taxes	**Virtual Taxes**	**Water Crossings**	**Write-Offs**	**Water Crossings**	**Network length**	**No. of connections**	**Soil Quality**
	Table 2.6	Table 2.6	Table 2.5	Table 2.9	Table 2.5	Table 2.2	Table 2.2	Table 2.4
B.V. Netbeheer Haarlemmermeer	**not reliable (5)**	**not reliable (5)**	n/a	**not reliable (2)**	n/a	(2)	**not reliable (5)**	(2)
DELTA Netwerkbedrijf B.V.	(1)	(1)	n/a	**not reliable (5)**	n/a	(2)	(2)	(2)
Eneco Netbeheer B.V.	(1)	**not reliable (5)**	**not reliable (4)**	**not reliable (5)**	(1)	(2)	(2)	n/a
Total Essent Group	(1)	(1)	n/a	**not reliable (5)**	n/a	(2)	(2)	(2)
Intergas Netbeheer B.V.	(1)	(1)	n/a	**not reliable (5)**	n/a	(1)	(1)	(1)
Netbeheerder Centraal Overijssel B.V.	(1)	(1)	n/a	(1)	n/a	(1)	(1)	(1)
NRE Netwerk B.V.	no data	no data	n/a	(1)	n/a	(2)	(2)	(1)
NV Continuon Netbeheer	**not reliable (5)**	**not reliable (5)**	n/a	**not reliable (5)**	n/a	(6)	(6)	(2)
Obragas Net N.V.	**not reliable (5)**	**not reliable (5)**	n/a	**not reliable (2)**	n/a	(2)	**not reliable (5)**	(2)
ONS Netbeheer B.V.	(1)	(1)	n/a	**not reliable (5)**	n/a	(1)	(1)	(1)
RENDO Netbeheer B.V.	(1)	(1)	n/a	(1)	n/a	(1)	(1)	(1)
Westland Energie Infrastructuur B.V.	(1)	(1)	n/a	(1)	n/a	(1)	(1)	(1)

(1) based on unqualified audit opinion
(2) disclosed data reconcile to accounting system (NB: financial data are only reliable if accompanied by an unqualified audit opinion)
(3) based on audit opinion and additional information from network company
(4) disclosed bookvalue is based on specific valuation report, not on historical cost (as required in audit instruction)
(5) use of estimated values and/or experience values and/or incorrect use of definitions audit instruction
(6) disclosed data reconcile to accounting system as per 15/2/2004 (instead of 31/12/2003)

We now discuss the potentially significant regional differences that we identified in Step 1, as well as the potential regional differences that required Step 2 before we could assess their significance.

4.2 Separately Quantifiable Regional Difference Factors

4.2.1 Water Crossings

In Step 1 we determined that water crossings costs were a potentially substantial regional difference for electricity companies. Three electricity companies provided data on water crossings. However, not all companies have complied fully with the data request. Delta, Eneco and Continuon submitted data relating to water crossings. However, DTe's auditor found that only Delta's data complied with the relevant instructions. Therefore we consider only Delta's data.

We first asked IBC to assess whether the total construction costs submitted by Delta were reasonable. Based on its experience of the industry, IBC estimated the minimum and maximum construction costs of this type of infrastructure. IBC found that the submitted data fell within this range, and concluded that the construction costs submitted by Delta were reasonable. IBC relied on quotes from engineering companies concerning the costs of actual projects, which it obtained on a confidential basis. We are not in a position to release the data.

Although the total cost of the water crossing fell within a reasonable range, it is an altogether different matter to recommend an adjustment to the tariffs. Delta would no doubt have incurred significant costs even if it had to extend similar cables on land. We therefore assess the potential "incremental" costs of the cables, which we define as the difference between the costs of constructing and maintaining the cables on a water crossing, and the equivalent costs for cables on land.

Calculating the incremental costs of water crossings

We calculate the total incremental costs per year using the following equation:

Capital costs of incremental investments + incremental maintenance costs + rental payments – revenue from sharing.

We describe below how we estimate each component of the equation.

Delta told us the total costs of a water crossing that it built in 2000. We deducted 15% from this figure, to reflect project management expenses such as technical studies and labour. 15% is in line with our experience, and has been used for years as a reasonable benchmark by National Grid, the operator of the high-voltage transmission and gas pipeline networks in the United Kingdom.[4] Delta would have incurred substantial project management costs even if the project were on land. We then estimated the raw materials cost of a 115 kV cable of the same length as the water crossing. Clearly Delta would have to buy a cable even if the project were entirely on

[4] *The Statement of the Transmission Transportation Charging Methodology* (1 May 2005), p.9.

land. IBC estimated the raw materials cost for an overhead cable on land in 2005, and we reduced it by applying a historical index of the price of carbon steel. Steel prices were substantially lower in the year 2000, so we reduced the IBC estimate accordingly. The results suggest that the raw materials costs would be approximately €114,000 per km in 2000. We multiplied the €114,000 by the length of Delta's cable, and subtracted the result from Delta's reported capital costs. We find that the incremental construction costs for the high voltage cable are 83% of the total construction costs reported.

Table 18: Water Crossings Analysis

Min construction cost, $ per km in 2005 (110kV cable)	[1]	IBC estimate	155,350
Max construction cost, $ per km in 2005 (110kV cable)	[2]	IBC estimate	186,420
Assumed construction cost, $ per km in 2005 (110kV cable)	[3]	Average of [1],[2]	170,885
Steel Price Index Jan-Sep 2005 (Apr-94 = 100)	[4]	See Note	146.58
Steel Price Index 2000 (Apr-94 = 100)	[5]	See Note	90.1
Assumed construction cost, $ per km in 2000	[6]	[3]x[5]/[4]	104,994
2000 average exchange rate, €/$	[7]	Bank of Canada	1.0861
Assumed construction cost, € per km in 2000	[8]	[6]x[7]	114,032
Length of >=110kV water crossings	[9]	See Note	8.006
Construction cost on land, 2000, excl. project management (pre-2001 assets), €	[10]	[8]x[9]	912,938
Actual water crossing construction costs 2000, €	[11]	See Note	20,951,035
Actual water crossing construction costs 2000 (excl. project management), €	[12]	See Note	18,218,291
Incremental construction cost, €	[13]	[12]-[10]	**17,305,353**
Incremental construction cost as % total	[14]	[13]/[11]	**83%**

[4],[5]: Source of steel price indices is the CRU Group (see http://www.cruspi.com/)
[9]: Only for the water crossing 'Borssele-Terneuzen / zwart'. Delta did not give information on the book value of its other HV water crossing ('Borssele-Terneuzen / wit').
[11]: Delta. Since the water crossing was constructed in 2000, we assume the end-2000 net book value is equal to the construction cost.
[12]: [11]/115% - assumes project management costs are 15% of investment costs (source: National Grid)

We anticipated an argument that our deduction for project management costs was excessive. Perhaps Delta would have an incentive to argue that the project management costs would be much lower if the project were on land, because it would be simpler to design and implement. However, our results still suggest that a water crossing costs about four times more than a normal land line, and we find it hard to believe that this ratio is biased on the low side. Our estimates allow many millions of Euros for the costs of dredging with specialised ships.

We then estimate the annual depreciation on the incremental net book value for the high voltage water crossing by dividing the end-2000 book value by 23.5. We assume the water crossing has a remaining lifetime of 23.5 years (it was only built in 2000). We assume a lifetime of 23.5 years for the water crossing because, according to the Electricity Agreements, Delta's RAB is depreciated over 23.5 years. As Delta has pointed out, 99% of the asset value of its water crossings is included in the standardised RAB. We calculate the return on the beginning-of-year incremental net book value using a weighted average cost of capital (WACC) of 6.6% for electricity companies (as determined by DTe). We assume that new investments (in existing water crossings) that occurred in a particular year were in place by the middle of the year. Hence we assume depreciation for new investments (over 50 years, consistent with the RAR) of 50% of the annual amount (i.e. amount of investment / 50 x 50%) and a return equal to the investment amount multiplied by the WACC over six months.

The smaller water crossings were built far earlier than 2000. One of them was built as early as 1958. As of 2000, the un-depreciated capital costs associated with the smaller water crossings were relatively small. They did not have a significant impact on the total estimate for Delta. However, we do include the incremental costs of the small water crossings as regional difference costs. For these water crossings we did not consider it reliable to calculate the incremental costs by deriving current estimates for the costs of raw materials and applying a steel price index that would extend back for decades. We thought it was most reasonable to take 83% of the net book value reported as at 31 December 2000, in line with our finding for the main water-crossing.

We also tried to estimate Delta's incremental operating and maintenance costs related to the water crossings. We analysed the documents Delta submitted describing the maintenance costs related to its water crossings. In our view, Delta has provided sufficient evidence that the maintenance costs given in its response to the data request relate to specific problems caused by having cables under water. We therefore include all of Delta's maintenance costs in our calculations.

Results

We estimated the total incremental costs, converted them to 2000 €, and calculated the average as a proportion of standardised costs (also expressed in 2000 €). Table 19 shows the results of our analysis.

Table 19: Incremental Costs of Water Crossings (electricity)

	Total costs per standardised cost				
	2000	2001	2002	2003	2000-3 average
Delta	2.3%	4.9%	3.5%	3.6%	3.6%

The incremental costs incurred by Delta because of its water crossings are lower than the average 4.2% of standardised costs that we reported in Step 1, because of the adjustments that we have made to focus on incremental costs. However, we conclude that the remaining costs are clearly substantial, and constitute a legitimate regional difference.

4.2.2 Salty Air

Step 1 suggested that salty air could be a regional difference. We use regression analysis to consider this issue further. We investigate the extent of the relationships between the number of insulators etc. on each network and the network's distance from the coast. Delta claimed that it had to install higher transmission towers and more large insulators, surge arresters, switching bays and Peterson coil grounding to address salty air problems. If it were true that companies nearer the coast required higher transmission towers and larger insulators etc., we would expect to find a strong negative relationship between a company's distance from the coast and the height of transmission towers and/or number of insulators etc. We investigate whether this is the case.

We cannot use data for all companies, since not all companies have submitted data relating to the number of insulators etc. as well as distance from the coast. Our analyses exclude those companies that did not provide data on relevant variables. As a result, some of our regression analyses are based on only a small number of data points. We have explained above how performing statistical analysis with a small number of data points can produce unreliable results. We are in some cases, however, able to increase the sample size by treating separate networks of one company as separate observations.

We are not able to investigate whether the height of transmission towers decreases with distance from the coast. This is because only Continuon and TenneT have distinguished between the numbers of transmission towers of different heights. By definition, the correlation between two data points is 100%. Therefore, statistical analysis of these data would not produce meaningful results.

We perform regressions of the number of insulators, the number of surge arresters, the number of switching bays and the number of Peterson coils, each regressed separately against distance from the coast. We first divide the number of insulators etc. by the length of overhead cable, in order to control for the different sizes of the companies. We include constants in the regressions. We only use the data for Delta, Essent and TenneT. DTe's auditor has informed us that Continuon's and Eneco's data are unreliable. The other companies did not submit the relevant data. However, we are able to increase our sample size by treating Essent's three networks separately.

We are unable to perform a regression involving the number of 31mm/kV insulators on distance from the coast. Four companies submitted data on the number of 31mm/kV insulators on their networks (Delta, Eneco, Continuon and TenneT). However, DTe's auditor considers the salty air data from Continuon and Eneco to be unreliable. As a result, we are left with only two data points. Consequently, we are unable to determine reliably whether being closer to the coast requires companies to install larger insulators.

Results

Table 20 shows the results of our analyses.

Table 20: Salty Air

	Distance from coast (km)	2000-3 average number per km of overhead cable: All insulators	31mm/kV insulators	Surge arresters	Switching bays	Peterson Coils
Delta	4.6	409	409	0.7	0.5	0.021
Essent - Network Noord	64.0	280	no data	0.1	0.3	0.001
Essent - Network Brabant	62.0	335	no data	0.3	0.4	0.017
Essent - Network Limburg	179.5	321	no data	0.3	0.3	0.008
Tennet	17.0	335	335	0.6	0.6	no data
Linear regressions against average distance from coast						
Coefficient		-0.32	n/a	-0.002	-0.001	-0.00006
R^2		22%	n/a	32%	60%	25%
t-statistic		-0.91	n/a	-1.19	-2.11	-0.82
Data points		5	2	5	5	4
Critical t-statistic (95%, one-tailed)		-2.354	n/a	-2.354	-2.354	-2.920
Coefficient significant?		NO	n/a	NO	NO	NO

Sources and Notes:

Conet, NRE, ONS, Rendo and Westland are excluded because they did not submit the relevant data.
Eneco and Continuon excluded because their data is unreliable.

We measure distance from coast from the point mid-way between the point on the company's ≥ 50kV network that is closest to the coast and the point that is furthest from the coast. Essent did not supply this information, so for Essent we use the average distance from the coast of each of its networks.

None of the regressions produces a statistically significant coefficient. This indicates that none of the variables (excluding number of 31mm/kV insulators, which we are unable to test) is closely linked to distance from the coast. This conclusion is reinforced by other information, such as the fact that some networks that are far from the coast use Petersen coil grounding. For example, Essent's Limburg network has more Peterson coil grounding per km than Essent's Noord network, despite being on average 116km further from the coast.

We also attempted some non-linear regressions based on equations of the following form:

Switching bays/km = γ (distance from coast)$^{\beta}$ which, in linear form, is LN(switching bays/km) = $\alpha + \beta$ LN(distance from coast)

We found only one potentially significant relationship. In the regression of LN(switching bays/km) against LN(distance from coast), we found a t-statistic of 2.53 (compared to a relevant critical t-statistic of 2.354) on the distance from coast variable, and a R^2 value of 68%. However, we do not believe that these results indicate that salty air is a regional difference. As a general rule, if you try investigating 20 different relationships, then one of them will on average appear to be significant with 95% confidence, since the mere definition of 95% confidence means a "one in twenty" probability that randomness created the appearance of significance. We have explored four different variables that could relate to the difference from the coast, and we have tried both linear and non-linear regressions. With a minimum of eight regressions tested, we are not surprised that one of them seems to be on the border line of significance. It would not be responsible to assign it any weight. We also have no inherent reason to believe that a logarithmic specification is more suitable than a simple linear specification. Finally, finding a correlation still does not prove causation. There is a close statistical relationship between the salaries of Presbyterian ministers in Massachusetts and the price of rum in Havana.[5] If Tiger Woods plays at a golf tournament on Sunday, the value of the US stock market tends to increase on Monday.[6] Although in our case we heard a plausible reason why it may cost more to build electricity networks by the coast, we would not expect to see a correlation with only one type of equipment while observing no correlation in any of the other categories.

We have been unable to test whether the number of 31mm/kV insulators is related to a network's distance from the coast. However, even if companies closer to the coast did need to install larger insulators, we anticipate that the overall incremental costs would be small. IBC has informed us that the costs of insulators comprise only around 1% of the cost of overhead lines. The difference in cost between large and small insulators should be around 30%, but could be up to 100% if a company did not buy the larger insulators in bulk. Hence the incremental cost to the company of installing larger insulators is only around 0.3% to 1% of the cost of overhead cables. This is likely to be a very small proportion of the company's total costs, particularly since for all companies except TenneT, less than 5% of the total network length is above ground.

We therefore conclude that, based on the available data, we do not believe salty air to be a substantial regional difference that we could measure reliably.

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[5] Darrell Huff, *How to Lie with Statistics* (United Kingdom: Penguin Books Ltd, 1991), p.90.

[6].Sirak, R. "Bullish on Tiger," *Golf World* (May 18, 2001).

4.2.3 *Taxes*

<u>All Taxes (precario & sufferance)</u>

In the section below we analyse precario and sufferance together.

Actual Taxes

We analyse the companies' data on actual taxes paid. We only consider the data that has received adequate endorsement from independent auditors.

We calculate actual taxes paid using two different methods. In the first, we assume that, since taxes paid to shareholders are effectively a dividend, they should not be considered. We therefore calculate actual taxes paid as:

Taxes stated in P&L – taxes received by shareholders – refunds for overpayments

ONS and TenneT did not indicate which portions were paid to shareholders, so we exclude these companies despite the endorsement of tax information from their auditors. TenneT is 100% state-owned, and the state does not levy precario. ONS should easily be able to provide this information, as to our understanding ONS only operates in one municipality, which is probably its most important shareholder. Both TenneT and ONS have had ample opportunity to comply with the data request. We also exclude Essent, because Essent could only *estimate* the distribution of payments between shareholders and non-shareholders on the basis of network length. We exclude Intergas' actual taxes paid because Intergas failed to provide information on the amount of actual taxes that was paid to shareholders.

In the second method of calculating actual taxes paid we calculate what actual taxes paid would be if we did not subtract taxes paid to shareholders. In this case, we include in the analysis all the data that met the reliability criteria.

Capitalised Taxes

We evaluate capitalised taxes under two different methods of calculation. The first method excludes capitalised taxes paid to shareholders. The second method calculates taxes without subtracting taxes paid to shareholders.

We calculate companies' effective annual capitalised taxes in two steps: first multiplying the capitalised amounts by an allowed return, and then adding a depreciation allowance. To calculate the return, we use a WACC of 6.6% for electricity companies and 6.8% for gas companies. These are the values used by DTe. To be consistent with the way DTe calculates standardised costs, we do not add inflation to these figures.

Rendo and CONET are the electricity companies with capitalised taxes. Gas companies Rendo, CONET and Intergas have capitalised taxes. Intergas' capitalised taxes were adequately audited, and we include them in our analysis. We also use the value of depreciation that Intergas submitted.

CONET has informed us that all of its capitalised taxes were paid to its shareholders. Consequently, we only include CONET's capitalised taxes in the calculations of taxes that include taxes paid to shareholders. We calculate CONET's capitalised taxes as follows: We estimate the 2000 book value of CONET's capitalised taxes by adding the end-2000 book value (provided by CONET) to the actual depreciation recorded by CONET in 2000. We then depreciate the capitalised amount on a straight-line basis, at a rate consistent with a depreciation period of twenty years.[7] Since the capitalised amounts were on average ten years old by the year 2000, we assume a remaining life of ten more years. We calculate the return in each year as the WACC multiplied by the book value at the start of each year.

Rendo reported very large capitalised taxes, which corresponded to an unusually short depreciation period of 12½ years. However, Rendo has proposed that, for the purposes of this analysis, we use a depreciation period of twenty years, which significantly reduces the results of the calculations. We assume that Rendo's annual depreciation is its book value at the start of 1999, divided by twenty.[8] Rendo has informed us that the total amount of capitalised precario was paid to the shareholders at that time. However, due to changes in municipalities Rendo is unable to specify which part of the precario was paid to Rendo's current shareholders. As a result, we only include Rendo's capitalised taxes in the calculations of taxes that include taxes paid to shareholders.

Virtual Taxes

For virtual taxes, we looked at the data companies provided on the taxes they would have had to pay if they did not have an exemption.

In the electricity sector, only Essent's auditor has provided adequate endorsement of virtual taxes. However, the virtual taxes reported by Essent were implausibly high (see Figure 2). We have accepted the capitalised taxes for CONET and Rendo because they form part of the RAB accepted by DTe, but we do not think that it is responsible to include virtual taxes for Essent that are of such a high magnitude and that DTe has not previously accepted.

Four gas companies submitted information on virtual taxes, but three of them failed to receive the necessary endorsement for virtual taxes from their auditors. In gas, we therefore look only at Essent's data. Despite the endorsement by independent auditors, we have concerns about the data on virtual taxes. The amount claimed by Essent is quite large (see Figure 3).

We recall that Eneco in the meetings opposed the inclusion of virtual taxes, emphasising that they could not be estimated reliably.

[7] This is consistent with the guidance given in the RAR (which specifies that the depreciation period should reflect the timing of the "asset", up to a maximum of 20 years).

[8] See above footnote.

Figure 2: Actual & Virtual Taxes (excl. taxes paid to shareholders) - Electricity

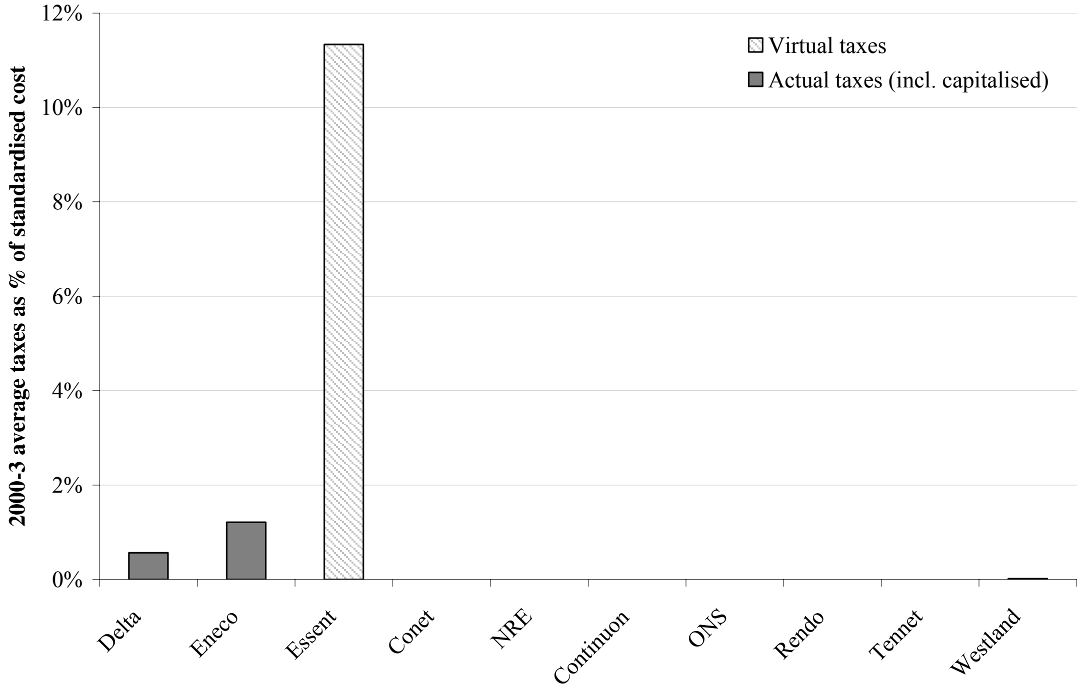
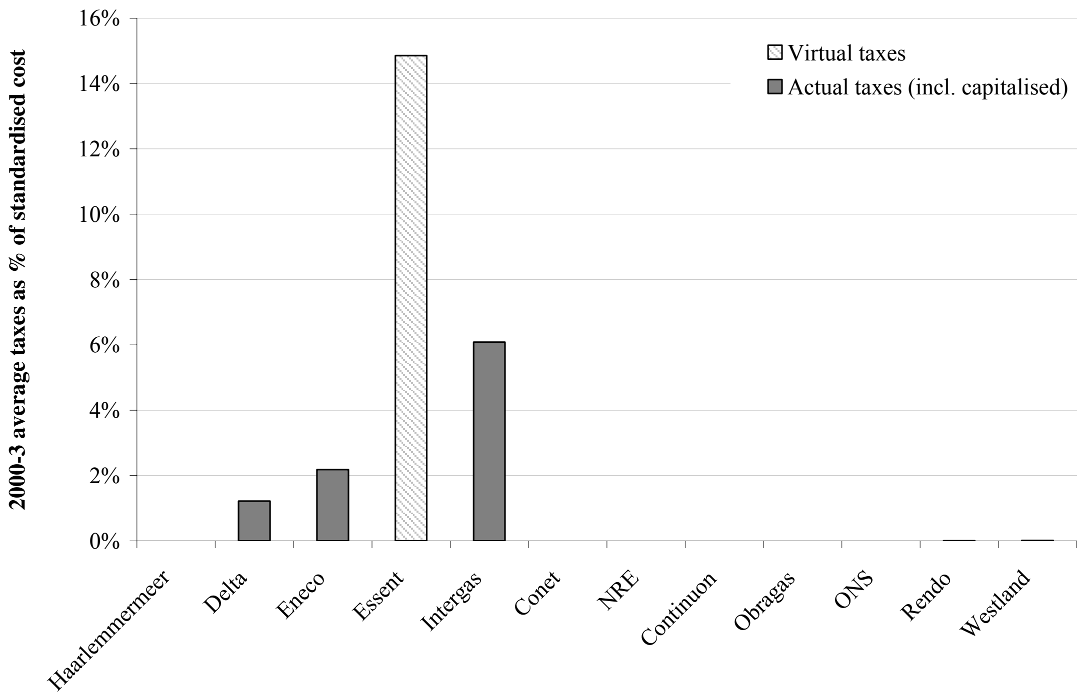


Figure 3: Actual & Virtual Taxes (excl. taxes paid to shareholders) - Gas



Results

Table 21 and Table 22 show companies' actual taxes paid and their capitalised taxes. We show taxes both including and excluding taxes paid to shareholders.

Table 21: Electricity Taxes (including capitalised taxes that are reliable)

	2000-3 average taxes as % standardised costs	
	Excluding taxes paid to shareholders [A]	Including taxes paid to shareholders [B]
Delta Netwerkbedrijf B.V.	0.57%	0.57%
Eneco Netbeheer B.V.	1.21%	2.27%
Total Essent Group		0.18%
Netbeheerder Centraal Overijssel B.V.		10.01%
NRE Netwerk B.V.	0.00%	0.00%
NV Continuon Netbeheer		
ONS Netbeheer B.V.		8.99%
Rendo Netbeheer B.V.	0.00%	13.05%
Tennet B.V		<1%
Westland Energie Infrastructuur B.V.	0.02%	0.02%

Sources and Notes:

Includes both precario and sufferance.
Excludes virtual taxes because the data do not make sense. In addition, DTe's auditor considers Eneco's data on virtual taxes to be unreliable.
Excludes Continuon's data because DTe's auditor considers it to be unreliable.
The value for NRE is 0% because NRE did not report any taxes.
[A]: Excludes TenneT and ONS, since these companies do not separate out taxes paid to shareholders. Excludes Essent, since Essent could only estimate the amount paid to shareholders. Excludes CONET's since all of CONET's capitalised precario was paid to shareholders. Excludes Rendo's capitalised taxes because Rendo was not able to specify how much of them were paid to current shareholders.
Rendo's taxes are very close to 0%.
[B] Although we do not have information on TenneTs exact standardised costs, it is clear that taxes are not substantial for TenneT. Assuming standardised costs of €40-60m, TenneT's taxes are likely to be below 0.02% of its standardised costs.

Table 22: Gas Taxes (including capitalised taxes that are reliable)

	2000-3 average taxes as % standardised costs	
	Excluding taxes paid to shareholders [A]	Including taxes paid to shareholders [B]
B.V. Netbeheer Haarlemmermeer		
Delta Netwerkbedrijf B.V.	1.22%	1.22%
Eneco Netbeheer B.V.	2.18%	4.08%
Total Essent Group		0.48%
Intergas Netbeheer B.V.	6.09%	8.28%
Netbeheerder Centraal Overijssel B.V.		8.60%
NRE Netwerk B.V.	0.00%	0.00%
NV Continuon Netbeheer		
Obragas Net N.V.		
ONS Netbeheer B.V.		9.57%
Rendo Netbeheer B.V.	0.01%	18.53%
Westland Energie Infrastructuur B.V.	0.02%	0.02%

Sources and Notes:

Includes both precario and sufferance.
Excludes data on virtual taxes because they do not make sense. In addition, DTe's auditor considers Eneco's data on virtual taxes to be unreliable.
Excludes data from Continuon, Haarlemmermeer and Obragas because DTe's auditor considers them to be unreliable.
The value for NRE is zero because NRE did not report any taxes.
[A]: Excludes ONS's data and Intergas' actual taxes paid, because these companies do not separate out taxes paid to shareholders. Excludes Essent, since Essent could only estimate the amount paid to shareholders. Excludes CONET, since CONET's taxes were paid to shareholders. Excludes Rendo's capitalised taxes because Rendo was not able to specify how much of them were paid to current shareholders.

Precario & sufferance analysed separately

Since the Dutch government may soon abolish precario, we also considered separately the companies' payments of precario and sufferance. We consider the data of all companies except Rendo (which did not provide separate numbers for precario and sufferance). However, only Essent, Continuon and Eneco reported having paid any sufferance.

We asked DTe's auditor to assess separately the reliability of the data on sufferance taxes submitted by the companies. Table 23 shows the results.

Table 23: Reliability of Data on Sufferance Taxes

	Electricity Table 2.8	**Gas** Table 2.6
B.V. Netbeheer Haarlemmermeer	n/a	no data
DELTA Netwerkbedrijf B.V.	no data	no data
Eneco Netbeheer B.V.	(1)	(1)
Total Essent Group	(1)	(1)
Intergas Netbeheer B.V.	n/a	no data
Netbeheerder Centraal Overijssel B.V.	no data	no data
NRE Netwerk B.V.	no data	no data
NV Continuon Netbeheer	**not reliable (4)**	**not reliable (4)**
Obragas Net N.V.	n/a	no data
ONS Netbeheer B.V.	no data	no data
RENDO Netbeheer B.V.	(1)	(1)
Tennet B.V	no data	n/a
Westland Energie Infrastructuur B.V.	no data	no data

(1) based on unqualified audit opinion (relating to this table)
(2) disclosed data reconcile to accounting system (NB: financial data are only reliable if accompanied by an unqualified audit opinion)
(3) based on audit opinion and additional information from network company
(4) original data (which reconcile to accounting systems) have been recalculated by the network company on experience values
(5) use of estimated values and/or experience values
(6) disclosed data reconcile to accounting system as per 15/2/2004 (instead of 31/12/2003)

In the case of electricity, almost all of Essent's actual taxes (net of refunds and payments to shareholders) are sufferance. Yet sufferance is still far below 1% of Essent's standardised costs. On average, only 6% of Eneco's net taxes are sufferance. Eneco's sufferance taxes vary significantly over time.

In the case of gas, Essent shows sufferance taxes in 2002 and 2003, but not in 2000 or 2001. On average sufferance accounts for only 6% of Eneco's total net taxes paid during 2000-3. In addition, sufferance is a very small proportion of standardised costs for all companies. Table 24 and Table 25 show our results. Although Continuon reported paying some sufferance taxes, we do not consider Continuon's data because they did not meet the criteria for reliability.

Table 24: Sufferance Taxes (electricity)

	Sufferance Taxes									
	As % of total taxes					As % of standardised costs				
	2000	2001	2002	2003	Avg 2000-3	2000	2001	2002	2003	Avg 2000-3
Eneco Netbeheer B.V.	0%	0%	131%	82%	6%	0.00%	0.00%	0.15%	0.15%	0.07%
Total Essent Group	97%	96%	96%	95%	96%	0.03%	0.02%	0.02%	0.02%	0.02%

Notes and Sources:

Excludes taxes paid to shareholders.
Excludes Continuon's data because DTe's auditor considers Continuon's data to be unreliable.
Sufferance taxes are greater than 100% of Eneco's taxes in 2002 because, in that year, Eneco received a precario payment from another party.
Essent estimated the amount of taxes paid to shareholders.

Table 25: Sufferance Taxes (gas)

	As % of total taxes					As % of standardised costs				
	2000	2001	2002	2003	Avg 2000-3	2000	2001	2002	2003	Avg 2000-3
Eneco Netbeheer B.V.	0%	0%	97%	93%	6%	0.00%	0.00%	0.25%	0.25%	0.13%
Total Essent Group	97%	95%	95%	94%	95%	0.03%	0.02%	0.02%	0.02%	0.02%

Notes and Sources:

Excludes taxes paid to shareholders.
Excludes Continuon's data because DTe's auditor considers Continuon's data to be unreliable.
Essent estimated the amount of taxes paid to shareholders.

Conclusion

Precario and sufferance, when taken together, are a regional difference for both gas and electricity companies. However, we do not believe that sufferance constitutes an independent regional difference. Sufferance is neither substantial nor sustained and therefore does not meet the criteria for a regional difference. If the precario is abolished, then we would not recommend considering sufferance separately as a regional difference.

Since the precario still exists at present, when calculating the net standardised costs for use in our connection density analysis we take into account both precario and sufferance.

4.2.4 Procurement of Energy and Capacity

We first analyse the sum of the following two types of costs as a proportion of standardised costs:

a) the costs of procuring energy and capacity to deal with transmission constraints (all voltage levels); and

b) the costs of procuring energy and capacity from other companies' higher voltage networks.

Table 26: Costs of Procuring Energy and Capacity

	2000-3 average cost/standardised costs		
	Relieving >= 110kV transmission constraints	Relieving < 110kV transmission constraints	Procuring transport capacity
DELTA Netwerkbedrijf B.V.	0%	0%	5%
Eneco Netbeheer B.V.	0.4%	0.02%	11%
Total Essent Group	0%	0%	5%
Netbeheerder Centraal Overijssel B.V.	0%	0%	24%
NRE Netwerk B.V.	0%	0%	22%
NV Continuon Netbeheer	0%	0.1%	5%
ONS Netbeheer B.V.	0%	0%	14%
RENDO Netbeheer B.V.	0%	0%	21%
Tennet B.V	<1%	0%	25-30%
Westland Energie Infrastructuur B.V.	0%	0%	26%

We include only Continuon's data for 2002 and 2003, since DTe's auditor does not consider the data for 2000 and 2001 to be reliable.
Although we do not have the exact value of Tennet's standardised costs, it is clear that costs of relieving transmission constraints are not substantial for Tennet. Tennet's average costs of relieving HV constraints are €0.06m. Clearly this is much smaller than 1% of Tennet's standardised costs (Tennet's composite output in 2000 was €53m). Assuming standardised costs of around €50-60m, Tennet's costs of procuring transport capacity are likely to be 25-30% of its standardised costs.

We note that the costs of relieving transmission constraints are very small and do not vary significantly between companies. We then consider together the costs of using the high-voltage (HV) grid (i.e. the costs of procuring transportation capacity and of relieving $\geq$ 110 kV transmission constraints). These appear to be substantial and to vary between companies. However, it is unfair to simply consider these costs and conclude that HV costs are a regional difference. Some companies own their own HV networks, and this is why they report lower procurement costs than other companies. If a company owns its own HV network, the costs still exist but unfortunately are not reported separately. It would therefore be inappropriate to compensate companies for costs only if they do not own their own HV network, indirectly penalizing other companies that may incur the same costs but do not report such costs separately. Moreover, management discretion is involved in deciding whether to expand a network to reduce constraints or to expand the network to include HV portions. If we adjust the tariffs based on the costs of procuring energy and capacity, then no company would want to expand its network to address constraints or to create or expand the HV network. The resulting incentives would be perverse. Restricting our analysis to the costs summarised in Table 26 would disadvantage the larger companies such as Essent and Continuon.

Table 27 illustrates that the companies having lower costs of procuring transportation capacity (from Table 26) tend to have a higher proportion of their composite output at the high voltage level (excluding TenneT, which is a special case). This makes us sceptical that the smaller companies such as CONET and Westland have a significant disadvantage from making payments for procuring transmission capacity. TenneT operates at the higher voltages, but presents an understandable exception to the general pattern, because TenneT does not have a complete distribution network.

Table 27: High Voltage Costs Analysis

	Costs of Procuring Transport Capacity as % SC [A]	HV Composite Output as % of Total (2000) [B]	LUP Revenues 2002 (€) [C]
DELTA Netwerkbedrijf B.V.	5%	19%	2,901,042
Eneco Netbeheer B.V.	11%	0%	5,396,471
Total Essent Group	5%	2%	18,402,482
Netbeheerder Centraal Overijssel B.V.	24%	0%	n/a
NRE Netwerk B.V.	22%	0%	n/a
NV Continuon Netbeheer	5%	1%	10,330,210
ONS Netbeheer B.V.	14%	0%	n/a
RENDO Netbeheer B.V.	21%	0%	n/a
Tennet B.V	25-30%	12%	9,829,242
Westland Energie Infrastructuur B.V.	26%	0%	n/a

Sources and Notes:

[A]: Companies and DTe.
[B]: DTe, and Brattle calculations of adjusted composite output.
[C]: DTe.

It would be extremely difficult to estimate precisely the costs associated with the high-voltage networks operated by the larger distribution companies. Companies' LUP revenues give some indication that the companies with a higher proportion of composite output at the HV level have significant costs associated with the high-voltage networks (see Table 27). However, the LUP revenues do not provide any insight into whether these costs were incurred efficiently. High LUP revenues could indicate a large number of HV customers or a large geographic expanse of high-voltage network. Without knowing whether the companies that own their own HV networks are efficient, we should not recommend tariff adjustments for the costs of procuring capacity on high-voltage networks.

Even if we were able to assess the efficiency of a large company's high-voltage network, we would still face the remaining task of assessing the relative efficiency of the following two types of companies: one that has to pay for high-voltage capacity from a larger company, and the larger company itself. If the larger company is inefficient, then the inefficient costs would contaminate the capacity procurement costs of all interconnected smaller networks.

After reviewing the issue carefully, we conclude that the transmission procurement costs cannot possibly signal regional differences among companies. If a small company procures transmission capacity from a large company, then the two companies will inherently face comparable costs as long as the charges for the capacity on the high-voltage network are cost-reflective. If the large company operates an inefficient high-voltage network, then the large company will suffer the consequences. The revenues charged by the large network, however, will be based on an efficiency target. By the end of the second regulatory period, all companies would be presumed equally efficient, so the larger company would not be able to charge the smaller company an amount that reflects the larger company's inefficiency. The smaller company would not suffer. If the large company already has an extremely efficient high-voltage network, then the smaller company may benefit from the relatively low costs for procuring transmission capacity. It is difficult to see how a small company suffers on average from the need to procure high-voltage capacity from a larger network. The mere existence of substantial capacity procurement costs, or varying costs among companies tells us nothing about whether the current efficiency targets for larger or smaller companies are inappropriate.

We conclude that the costs of relieving transmission constraints and procuring capacity do not constitute a regional difference capable of reliable measurement that could warrant adjustments to the tariffs. We see no significant difference between companies that own their own high-voltage grid and those that must pay for the procurement of capacity from others. This reinforces the concerns that we expressed in Step 1, involving the potential role of management discretion and the perverse incentive effects of treating these costs as a regional difference.

4.2.5 Consumer Behaviour/Write-Offs

Step 1 found that the write-off costs of the electricity company, Essent, were on the borderline of significance. However, Essent's data do not meet the criteria for reliability. Only the data of five electricity companies are reliable. As Table 28 shows, the remaining companies' write-offs range from only 0.2% to 1.0%. The average across all companies (assuming 0% for companies with unreliable data) is 0.3%. The maximum variation from the mean is only 0.7%. Aside from the problems in deriving conclusions from only five data points, the range of variation is clearly too low to indicate a substantial regional difference. We therefore conclude that write-offs are not a substantial regional difference.

Table 28: Write-Offs (electricity)

	2000-3 average cost/SC	Difference from average
DELTA Netwerkbedrijf B.V.	0.3%	0.0%
Eneco Netbeheer B.V.	0.0%	-0.3%
Total Essent Group	0.0%	-0.3%
Netbeheerder Centraal Overijssel B.V.	0.8%	0.4%
NRE Netwerk B.V.	0.6%	0.3%
NV Continuon Netbeheer	0.0%	-0.3%
ONS Netbeheer B.V.	0.0%	-0.3%
RENDO Netbeheer B.V.	0.2%	-0.1%
Tennet B.V	0.0%	-0.3%
Westland Energie Infrastructuur B.V.	1.0%	0.7%
Company Average	0.3%	0.0%

Based on total write-off costs (using actual write-offs) calculated from data in companies' submissions and adjusted for inflation. Eneco, Essent, Continuon, ONS and TenneT values assumed to be zero because data unreliable.

4.2.6 Peak Load

In Step 1 we discussed two issues relating to peak load. Below we discuss these issues in further detail and consider the reliability of the submitted data.

The historical calculation of composite output in 2000 did not incorporate a fixed component per kW in the electricity tariffs for residential customers. From a theoretical perspective, the composite output would relate more directly to costs if we imputed to the tariffs a fixed component per kW. However, our study does not attempt to revisit past calculations and redistribute revenues among the companies as a result. It is likely that a fixed component will apply to residential consumers from the third regulatory period onwards. As the tariff structure and other factors change in the future, changes may occur in the accuracy with which the composite output measures the relative costs of serving customers with different load profiles. It is not our place to speculate about the potential inaccuracies of future tariff structures under future conditions. However, much of our analysis seeks to measure regional differences with respect to historical data. In performing statistical analyses we are interested in using the most accurate data possible. We therefore consider whether correcting for a theoretical deficiency in the 2000 composite output would have a significant impact on our statistical analyses. We have determined that our statistical analyses do not provide different conclusions based on alternative ways of measuring the historical composite output.

We have also looked at the data the companies have submitted on annual volumes and peak load. We do not analyse the data submitted by Eneco and Continuon because they do not meet the criteria for reliability. We find a moderate correlation between load factor and cost per composite output. The correlation is negative, as would be expected if companies with lower load factors have higher costs per composite output. However, we have reason to question the data. In particular, there is a wide range in load factors: from 24 to 66% (see Table 29). The Brattle Group's experience and IBC's experience both suggest that such a wide range of load factors is implausible. We might expect a large industrial customer to have a load factor that exceeds 60%, and a residential customer to have a load factor in the range of 30%. However, it is simply not plausible that Essent, which serves a mixture of residential customers and industrial customers, has an average load factor as low as 23.8%. Even if we exclude Essent as an outlier, we see no strong relationship of the nature expected. For example, Delta has high costs per composite output, even after considering its water crossings and taxes. The high costs per composite output coincide with a very high load factor.

Table 29: Peak Load and Annual Volumes

Company	Standardised Costs 2000 (€m) [A] DTe	Composite Output 2000 (€m)* [B] DTe	Costs per Comp Output [C] [A]/[B]	Peak Load (kW) [D] Companies	Total MWh [E] Companies	Load Factor [F] [E]/([D]x8760/1000)
All networks						
DELTA Netwerkbedrijf B.V.	66	55	1.20	298,200	1,463,664	56.0%
Total Essent Group	784	672	1.17	11,086,343	23,107,678	23.8%
Netbeheerder Centraal Overijssel B.V.	12	12	1.04	84,108	444,221	60.3%
NRE Netwerk B.V.	25	24	1.04	171,800	926,719	61.6%
ONS Netbeheer B.V.	7	7	0.99	50,280	291,728	66.2%
RENDO Netbeheer B.V.	9	7	1.22	50,987	266,008	59.6%
Westland Energie Infrastructuur B.V.	25	23	1.09	159,893	626,382	44.7%
					Correlation beween [C] and [F]	-40.1%

Notes:

* Unadjusted

Tennet is excluded because it operates 150kV network and has substations from 150kV to lower tensions, which falls outside the data request.

Eneco and Continuon are excluded because Dte's auditor considers their data unreliable.

We conclude that the differing load factors of the companies do not constitute a significant regional difference that we can measure reliably.

4.3 Degree of Urbanisation/Population Density

We investigate the relationship between population density and costs. Since we use data on population density from the Dutch Central Bureau of Statistics, we are able to use the full sample of companies in the electricity analysis. We do not include TenneT because it is not comparable to other companies in terms of population density.

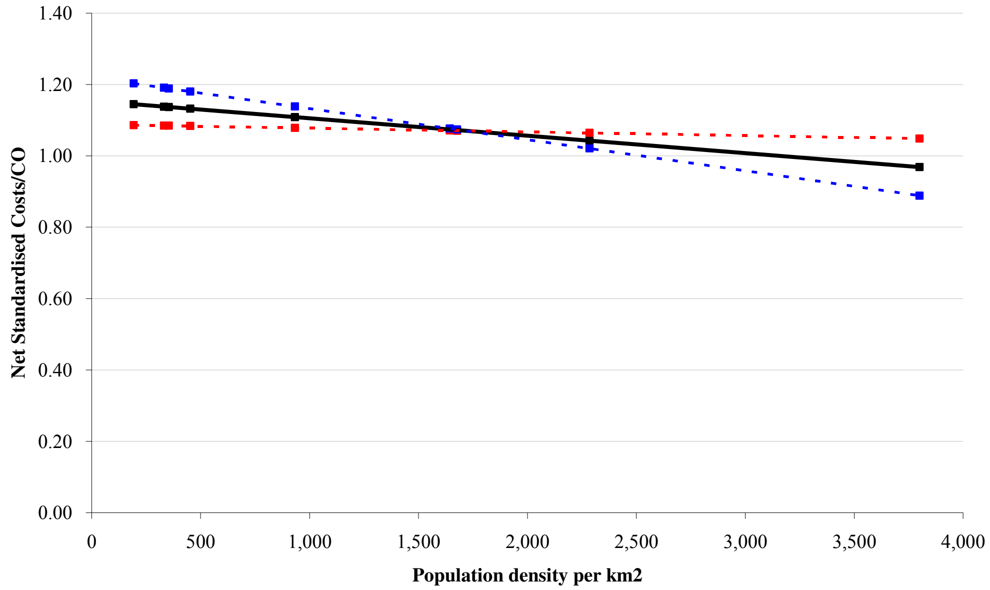
Electricity Regressions

1) Net standardised costs/unadjusted composite output = α + β (population density)

With a t-statistic of 3.01, 7 degrees of freedom and an R^2 of 56%, the coefficient on population density is statistically significant from zero in the linear equation above.

However, we are concerned about the implications of the results of the regression. In particular, large standard errors cause a wide range in the possible values of the coefficients. As a result, the regression results imply a wide range in values of net standardised costs/composite output (net SC/CO). For example, as Figure 1 shows, the results of the regression imply that the efficient value of net SC/CO for ONS could be as low as 0.89 or as high as 1.05. Furthermore, as we explained in the discussion of salty air, a correlation does not imply causation.

Figure 4: Values of net SC/CO predicted by regression



2) Net standardised costs/connection = α + β (population density)

Population density does not seem to help explain standardised costs per connection. The variable is not statistically significant in the above regression. We also investigated whether there was a non-linear relationship between the above variables. We found that no statistically significant relationship existed.

Gas Regressions

We perform similar regressions for the gas companies. We perform the regressions in two ways: including and excluding ONS. ONS is a clear outlier, because its population density is eight times higher than the average across the other companies. We do not find population density to be a statistically significant variable. The results do not depend on the inclusion of ONS. Including ONS only reduces the significance of the analyses. Even without ONS, we find that in the regression

Net standardised costs/composite output = α + β (population density)

the t-statistic on population density is only 1.2 and the R^2 14%. Including ONS reduces both the t-statistic and the R^2.

Conclusion

Based on the above results and the concerns that we have described, we do not believe that population density is a regional difference whose cost implications we can measure accurately.

4.4 Type/Quality of Soil

None of the companies has been able to provide an engineering study that could allow us to measure the costs associated with poor soil. The only study submitted was not a scientific study retained in the ordinary course of business. It was prepared as part of a debate over tariffs with DTe. The document contained some assertions concerning the costs of poor soil, but did not disclose its methodology or the underlying data set examined. The document did not provide sufficient detail to test its assertions.

In the absence of a study concerning poor soil, we considered another possibility: that we could measure the costs of poor soil using statistical analysis. Perhaps we could analyse the net errors as a function of the proportion of connections in poor soil. However, as shown in Section 3.1.10, only four electricity companies and five gas companies provided adequate data for us to estimate the proportion of their connections lying in poor soil areas. With two variables in the regressions, this means that the degrees of freedom would only be two in the case of electricity and three in the case of gas. As we have previously explained, no regression can provide meaningful results with so few degrees of freedom. We therefore conclude that the available data preclude us from measuring reliably any regional difference associated with soil. We do not have any reliable engineering study, and the data cannot support any broader statistical analysis.

The lack of data and of any study estimating the additional costs associated with poor soil have prevented us from measuring accurately the incremental costs of poor soil. However, we do not expect the additional costs of laying pipes/cables in poor soil to be substantial. IBC has informed us that the incremental maintenance costs associated with poor soil are likely to be small. IBC derived its conclusions on the basis of its past experience with different soil types. In addition, if soil quality were a serious problem, we would have expected that at least one of the companies would have undertaken a study on this issue during the normal course of business. The absence of any such study suggests that soil quality is not a serious problem. These considerations, coupled with our inability to measure reliably the costs of poor soil, compel us to reject soil conditions as a basis for prospective tariff adjustments.

4.5 Connection Density

Our analysis of the literature on the relationship between connection density and costs (see Appendix II) indicates that it remains an empirical question whether any relationship exists between these variables in the Netherlands.

We investigate the connection density issue empirically for the Dutch network companies by performing several regressions to assess whether there is a relationship between connection density and costs.

Variables

The regressions use the following variables:

Independent variables (connection density):

The companies requested that we use the following two variables to represent connection density:

- number of connections per km2 of network surface area ("Measure A")
- number of connections per km of network length ("Measure B")

For Measure A, we use circuit length. For Measure B, we consider the surface area of land plus inland water. For electricity we use the surface area of land plus inland water that we calculated for each company based on CBS data. We do not use the areas reported by the electricity companies themselves because they imply a total area much larger than that of The Netherlands. For gas we take the area of land plus inland water reported by the companies and assume that the area of land plus inland water for Intergas is the same as Intergas' land area (Intergas did not report a separate value for surface area including inland water). This gives a total area that is very close to the total area of The Netherlands that the CBS reports. We do not use the values for the gas companies that we calculated based on the CBS data for municipalities, because they imply a total area of land plus inland water that exceeds by 11% the CBS total for the Netherlands.

We believe Measure B is the most appropriate measure to use. We see no strong theoretical reason why costs should be related to connections per km2. Simply covering a lot of square kilometres does not necessarily relate to costs, since costs are related to network configuration. We can imagine situations where different companies have roughly the same total number of connections per square kilometre, but far different amounts of infrastructure in place per connection. Measure B tries to measure the amount of infrastructure more accurately by reference to the total network length per connection. However, at the request of some of the companies, we consider Measure A as well as Measure B.

Dependent variables:

- *Net errors* (a measure of efficiency): The current tariff system is based on the belief that the "errors" between actual costs and costs predicted on the basis of composite output reflect differences in the relative efficiencies of the companies. One way of understanding our current investigation is to determine whether specific regional difference factors could help explain the "errors". If any of the potential factors explains a significant part of the "error", then perhaps it makes a meaningful and reliable contribution to understanding the total differences in costs among the companies.

  We calculated the "net errors" by calculating the standardised costs predicted by a regression against composite output. For electricity we ran separate regressions using unadjusted and adjusted composite output. We used data for 2000 for electricity companies and 2001 for gas companies. We did not include a constant in the regression since DTe originally assumed standardised costs to be directly proportional to composite output. The regression's errors are the difference between actual standardised costs in 2000 for electricity and 2001 for gas and the standardised costs predicted by composite output. We then took out from the errors the taxes and incremental water crossings costs in 2000 (for electricity) and in 2001 (for gas). This gave us a variable called "net errors". We investigate whether connection density can explain the net errors.

- *Net standardised costs/composite output*: We also calculated a variable called "net standardised costs", by subtracting from standardised costs the regional differences that we quantified separately. We subtracted the regional differences shown in Table 30 and Table 31. We then divided the net standardised costs by the composite output. For electricity we run separate regressions using standardised costs/unadjusted composite output and standardised costs/adjusted composite output. Since the variable *standardised costs/composite output* is an indicator of companies' relative efficiencies, *net standardised costs/composite output* measures what the companies' perceived efficiencies would be after considering the regional differences that we quantified separately. It is important to subtract the regional differences that have been quantified separately before performing the analyses of connection density. To illustrate, note that the original calculations of standardised costs per composite output suggested that Delta was relatively inefficient. We have previously disclosed that Delta faced higher taxes and had incremental water crossings costs. After subtracting these costs, Delta no longer appears so inefficient. It is important to consider that part of the perceived inefficiency has already been explained by taxes and water crossings before we proceed to investigate what residual amount of perceived inefficiency, if any, may involve Delta's relatively low connection density.

Table 30: Regional Difference Costs (electricity)

	Taxes 2000 (2000 €)	Incremental water crossings costs 2000 (2000 €)	Total (2000 €)
DELTA Netwerkbedrijf B.V.	318,611	1,484,116	1,802,727
Eneco Netbeheer B.V.	10,882,613		10,882,613
Total Essent Group	-		-
Netbeheerder Centraal Overijssel B.V.	-		-
NRE Netwerk B.V.	-		-
NV Continuon Netbeheer	-		-
ONS Netbeheer B.V.	-		-
RENDO Netbeheer B.V.	19		19
Tennet B.V	-		-
Westland Energie Infrastructuur B.V.	4,800		4,800
Total	11,206,043	1,484,116	12,690,159

Note: taxes do not include taxes paid to shareholders.

Table 31: Regional Difference Costs (gas)

	Taxes 2001 (2001 €)	Incremental water crossings costs 2001 (2001 €)	Total (2001 €)
B.V. Netbeheer Haarlemmermeer	-		-
DELTA Netwerkbedrijf B.V.	239,013		239,013
Eneco Netbeheer B.V.	10,093,845		10,093,845
Total Essent Group	-		-
Intergas Netbeheer B.V.	2,148,860		2,148,860
Netbeheerder Centraal Overijssel B.V.	-		-
NRE Netwerk B.V.	-		-
NV Continuon Netbeheer	-		-
Obragas Net N.V.	-		-
ONS Netbeheer B.V.	-		-
RENDO Netbeheer B.V.	1,614		1,614
Westland Energie Infrastructuur B.V.	3,200		3,200
Total	12,486,532		12,486,532

Note: taxes do not include taxes paid to shareholders.

- *Net standardised costs per connection:* At the request of some of the companies, we also analyse the relationship between net standardised costs per connection and connection density.

Data

For the electricity companies, several companies submitted data that do not meet the reliability criteria. We therefore do not consider the data on network length from Eneco, Essent and Continuon. We exclude TenneT from our statistical analyses out of a concern that its absence of direct connections to residential customers made it incomparable to the other companies in terms of connection density. CONET only submitted data on route length, and NRE only submitted data on circuit length. We perform our analysis on circuit length but assume a circuit length for CONET equal to its route length. For regressions concerning the number of connections per km2 we therefore have a sample of nine companies. For regressions involving the number of connections per km of network length, we have a sample of six companies.

Of the gas companies, DTe's auditor considers Haarlemmermeer's and Obragas' data on number of connections to be unreliable. We are left with a sample of ten companies.

One of the companies suggested that we perform separate regression analyses on small companies and on large companies. However, doing this would further reduce the sample size, which would reduce the reliability of the results. Since the analyses that combine all the companies do not have sufficient observations to produce reliable results (see discussion below), there is no point in repeating these analyses for subsets of companies.

We consider 2000 standardised costs for electricity companies and 2001 standardised costs for gas companies. Some of the companies have expressed concern that using 2000 standardised costs for electricity companies is inappropriate because the 2000 numbers are incorrect. In particular, Essent's 2000 costs are incorrect because for 2000-2 Essent reported as operational costs part of its revenue from connection charges. In 2002 this error was equivalent to an overestimation of costs by almost €64m. DTe expects that Essent's 2000 and 2001 costs were incorrect by a similar amount. The standardised costs for gas companies were not affected by this problem. Despite the potential problem, we use the original 2000 standardised costs for Essent in the electricity analysis. We do not have the true value for Essent's costs in 2000. We discuss later the implications this has on our connection density analysis.

Regressions - Electricity

We perform several linear regressions, all of which include a constant:

1) Net standardised costs/composite output = α + β (connections/km2)

2) Net standardised costs/composite output = α + β (connections/km)

3) Net error = α + β (connections/km2)

4) Net error = α + β (connections/km)

We also investigate whether there is a non-linear relationship between connection density and efficiency. We convert non-linear equations to linear equations by taking the natural logs of the variables. Converting the equations in this way allows us to continue to use the standard significance tests that are only really suitable for linear regressions.

5) Net standardised costs/composite output = γ (connections/km2)$^{\beta}$ which, in linear form, is LN(Net standardised costs/composite output) = α + β LN(connections/km2)

6) Net standardised costs/composite output = γ (connections/km)$^{\beta}$ which, in linear form, is LN(Net standardised costs composite output) = α + β LN(connections/km)

In response to NRE's concern that the number of high-voltage connections is also related to costs in a positive way, we perform an additional regression that considers the different proportions of composite output at the high voltage level. We use the following equation:

7) Net standardised costs/composite output = α + β (connections/km2) + γ(% of composite output at HV level)

We also run the following two regressions, to investigate whether net standardised costs per connection are related to connection density:

8) Net standardised costs/connection = α + β (connections/km2)

9) Net standardised costs/connection = α + β (connections/km)

Table 32 shows the results of our connection density regressions that use unadjusted composite output. Repeating the regressions using adjusted composite output did not alter the results.

Table 32: Regression Results - Electricity

No.	Dependent variable	Independent variable(s)	Estimated coefficient	Max coefficient	Min coefficient	Ratio max/min	t-statistic	d.f.	Critical t-stat (2-tailed) 95%	Statistically significant? 95%	R^2
1)	**Net SC/CO**	**Connections per km2**	**- 0.00009**	**- 0.00014**	**- 0.00003**	**4.6**	**-2.95**	**7**	**-2.447**	**Yes**	**55%**
2)	Net SC/CO	Connections per km	- 0.003				-2.04	4	-3.181	No	51%
3)	Net error	Connections per km2	- 2,975				-0.25	7	-2.447	No	1%
4)	Net error	Connections per km	- 63,727				-1.76	4	-3.181	No	44%
5)	**LN(Net SC/CO)**	**LN(Connections per km2)**	**- 0.06**	**- 0.08**	**- 0.04**	**2.2**	**-5.04**	**7**	**-2.447**	**Yes**	**78%**
6)	LN(Net SC/CO)	LN(Connections per km)	- 0.15				-2.34	4	-3.181	No	58%
7)	Net SC/CO	Connections/km2 & % of CO at high voltage	0.19 - 0.0001				0.56 -2.45	6	-2.571	No No	58%
8)	Net SC/connection	Connections per km2	- 0.06				-1.99	7	-2.447	No	36%
9)	Net SC/connection	Connections per km	- 2.82				-2.64	4	-3.181	No	64%

Note: the minimum and maximum coefficients are calculated assuming a 95% confidence interval.

We look at nine regressions. These regressions involve seven sets of variables (regressions 1 and 5 involve the same variables as each other, as do regressions 2 and 6). Only one of the sets of variables (two of the regressions) gives a statistically significant result.

Analysis of Results for Electricity Companies

We have several concerns about these results.

First, we are unconvinced that the apparent existence of a significant relationship within one set of variables out of the seven tested indicates that connection density is related to costs. By definition, “95% confidence” implies a one in twenty probability that randomness created the appearance of significance. We have tested seven possible sets of variables for electricity, and another six set of variables for gas companies. As we explain below, none of the gas regressions were significant. We would expect simply as a matter of luck that one of these thirteen sets of variables might show statistical significance. We observed a similar problem in our analysis of the salty air issue (Section 4.2.2).

Our analysis of the connection density literature (see Appendix II) suggests that urban networks may in fact experience some higher costs than rural networks (e.g. higher wages), despite their higher connection density. Unfortunately, it is not feasible to isolate the potential effects of connection density in the Netherlands by adding to our regressions other variables that may capture the cost disadvantages of large cities. The data sample is too small to include connection density and population density simultaneously in an equation, and to start adding more independent variables such as the potential wage differences among areas of the Netherlands. Our insignificant results for most of the relatively simple regressions may simply indicate that the two effects of connection density and urbanisation largely offset each other in the Netherlands.

Furthermore, finding a statistically significant negative relationship between connection density and costs does not provide evidence that lower connection density *causes* higher costs Statistical significance of a relationship does not prove that the variables are causally related (and, if so, in which direction the causation operates).

Second, the results of the two significant regressions do not seem to provide a sufficiently reliable indication of the magnitude of the effect of connection density on costs (if any). We have considered in detail the results of the two significant regressions. We are concerned by the range in coefficients on the connection density variable that the regressions imply are possible. For example, we are unable to tell from the results of regression 1) whether a one unit increase in connections per km2 causes a 0.00003 unit decrease in net standardised costs per composite output (net SC/CO), or a unit decrease in net SC/CO almost five times that (see max/min column of Table 32). Similarly, we are unable to tell from the results of regression 5) whether a one unit increase in LN(connections/km2) causes a 0.8 unit decrease in LN(net SC/CO) or a decrease half that.

Third, the apparent negative relationship between connection density and costs seems to be driven by only a few data points. According to the submitted data, there is a group of electricity companies with roughly the same connection density but different costs (Rendo, Delta, Westland, Essent and Continuon) and a group of companies with similar costs but very different connection densities (CONET, ONS, NRE, Eneco and Continuon). This implies that an additional variable – management discretion/inefficiency – could explain at least part of the differences between the companies' net SC/CO and connection density.

The graphs in Appendix III show the relationships between connection density and costs for the companies under the two different measures of connection density discussed previously: connections per km2 ("Measure A") and connections per km ("Measure B"). The appearance of a relationship would seem to derive from the data for Rendo, Delta, Westland and Essent. Under both measures of connection density, Rendo and Delta seem to have lower connection density and higher costs than most other companies. This is true even after adjusting for Delta's water crossings and taxes, because the graphs involve the "net" standardised costs as explained earlier. From the results for Measure A, Essent also seems to have lower connection density and higher costs than most of the other companies. Essent's data is not shown for Measure B because DTe considers it unreliable. However, we see no relationship between connection density and costs if we look only at Continuon and the four other companies that have somewhere between 600 and 2,000 connections per square kilometre.

The case of Continuon indicates that the regression equations that include only connection density as a dependent variable may be mis-specified. Comparing Continuon to the other low density companies suggests that there is likely to be a factor other than or in addition to connection density that explains the differences in companies' net costs per composite output. There is a group of electricity companies with roughly the same connection density but different costs. Continuon has one of the lowest densities per square kilometre, right in between Westland on the one hand, and the group Rendo/Delta/Essent on the other. However, Continuon's standardised costs per composite output are extremely close to the average for the four high-density companies. If Continuon has only one fifth the density of ONS but roughly the same costs per composite output, it is difficult to believe that there is any significant relationship between density and costs. Focussing on our "significant" regression (the data underlying this regression are in the top left-hand graph in Appendix III), Continuon's data seem to suggest that Rendo, Delta, Essent and Westland are all inefficient. A reasonable response would be to eliminate those four companies from the analysis, focussing solely on the efficient ones.

We exclude Continuon's data from the analysis that uses Measure B because Continuon's data on network length is unreliable. Several companies have invited us to accept data on network length despite the lack of sufficient endorsement from an auditor or other data problems.

Continuon's reported network length did not secure the necessary endorsement from an auditor, but even if we considered it, Continuon would continue to appear as a relatively low-density company, raising the suspicion that the other low-density companies were inefficient. Even without Continuon, the example of Westland already raises this problem if we consider standardised costs per composite output. Rendo and Delta have almost identical densities, but much higher costs per composite output. If we eliminated Rendo and Delta from the regression analysis, we would have even greater difficulties detecting any causal relationship between density and costs.

Fourth, a closer inspection suggests that there are also problems with the data used in the regressions. Westland's case provides an example of these data problems.

Under Measure B, Westland has the same density as Rendo and Delta (see Appendix III). Under Measure A, Westland is twice as dense as Rendo and Delta. The conflicting pictures of relative density reduce our confidence in the data.[9]

Since the data and results are very different for Measures A and B, we need to consider which measure is most appropriate for the analysis. As explained above, we believe that, from a theoretical perspective, Measure B (connections/km) is more appropriate. However, we have observed that there may be errors in some of the companies' data on network length, and the statistical results are insignificant. We could focus on Measure A if we thought that the answer to the Westland puzzle involved inaccuracies in the audited data for network length. An important advantage of Measure A over Measure B is its reliance on objective data from the CBS concerning the square kilometres covered by each network.

If we disregard the data on network length despite the receipt of auditor endorsements, we still have to trust the data concerning the number of connections before having confidence in Measure A, since it reports density as a function of connections per square kilometre. However, some of the connection data seem strange.[10]

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[9] The striking difference in Westland's relative density under alternative measures would indicate one of two problems. Perhaps the data are accurate, and a significant difference arises between the two alternative measures of density because of Westland's unique network configuration. If the data are accurate, then Westland just by chance happens to have the same network length per connection as Rendo and Delta, but covers only half the square kilometres per connection. If this is true, then we would prefer an analysis based on density measured by reference to network length, since network length relates most directly to costs. However, none of our regressions involving network length were significant, perhaps in part because several companies failed to provide data that secured sufficient endorsement from auditors.

The second problem could involve the lack of reliable data. Perhaps Westland does not have a unique network configuration. The puzzle of its connection density could be explained by a serious error in the reported network length. As explained elsewhere in this report, we have found problems with some of the data despite the endorsement of auditors.

[10] For example, Westland reports an unusually low number of connections per composite output. This causes an oddity that is apparent in our graphs: Westland looks like a fairly low-cost company when we consider its standardised costs per composite output, but looks extremely inefficient when we consider its costs per connection. The Westland data raises the possibility that Westland may have understated its total number of connections. Alternatively, perhaps Westland has the good fortune of having considerable composite output per connection. However, this would not seem likely, since Westland's percentage breakdown of connections into different voltage categories is in line with the results of other companies.

We are concerned that the only regressions that produced significant results were those involving connection density measured as connections/km2 ("Measure A"). As we explained above, we see no particular theoretical reason why costs should be related to connections per km^2. Given this, and the unreliability of the regression results (discussed above), we do not believe it would be responsible to make judgments (particularly about the amount of any compensation) on the basis of these regression results.

Finally, we thought of the most charitable interpretation of the data concerning connection density, from the perspective of the low-density companies. An extreme view would somehow conclude with confidence that connections per square kilometre represent an accurate cost-driver. In this case we would disregard the audited network length data as unreliable, but would assume that the data concerning the number of connections are accurate.

However, even an extreme view would recognize that Continuon has similar costs per composite output to companies that are up to five times more dense. Even an extreme view would at most reward the low density companies for the difference between Continuon's net standardised costs per composite output and the average of the four high-density companies. This extreme view would trust that the entire two percentage point difference between Continuon's costs per composite output and the average of the four high-density companies was due to the higher costs of having a lower density. The extreme view would not attach any importance to the possibility that Continuon's two percentage point difference could reflect some combination of luck, data measurement problems, or perhaps a slight difference in efficiency between Continuon and the four high-density companies. We conclude that even an extreme view would not recognize differences in connection density that exceed 1% or 2% of the standardised costs of the least dense companies.

Regressions - Gas

For the gas companies, we perform the same regressions as for the electricity companies (excluding regression 7, which is not relevant in the case of gas, and without repeating the analysis using adjusted composite output). Table 33 shows the results.

Another oddity involves Essent, which reported a lot of network length associated with municipal lighting. Since Essent's data did not receive the endorsement of auditors, we did not consider Essent's network length. However, it is odd for Essent to report so much municipal lighting cable, while indicating no connections whatsoever in the category where we would expect to see municipal lighting.

Conet raises even a starker puzzle than Westland. If we look at connections per square kilometre, Conet is five times as dense as Delta. If we look at connections per kilometre of network length, Conet is only about a third denser than Delta. As with Westland, the large data discrepancy could have two different explanations: one which involves unique network configurations among the companies, and one that involves serious data problems. We do not know how to pick between the two explanations.

Table 33: Results of Gas Regressions

No.	Dependent variable	Independent variable(s)	Coefficient(s)	t-statistic (s)	d.f.	Critical t-stat(s) (2-tailed, 95%)	Statistically significant?	R^2
1)	Net SC/CO	Connections per km2	- 0.0002	- 1.06	8	-2.306	No	12%
2)	Net SC/CO	Connections per km	- 0.003	- 1.06	8	-2.306	No	12%
3)	Net error	Connections per km2	- 1,186	- 0.22	8	-2.306	No	0.6%
4)	Net error	Connections per km	- 20,972	- 0.28	8	-2.306	No	1.0%
5)	LN(Net SC/CO)	LN(Connections per km2)	- 0.14	- 1.62	8	-2.306	No	25%
6)	LN(Net SC/CO)	LN(Connections per km)	- 0.21	- 1.14	8	-2.306	No	14%
7)	Net SC/connection	Connections per km2	- 0.04	- 0.68	8	-2.306	No	5%
8)	Net SC/connection	Connections per km	- 0.75	- 1.00	8	-2.306	No	11%

Excludes Obragas and Haarlemmermeer because of unreliable data.

Connection density is not statistically significant in any of the regressions and the values of R^2 are low. This indicates that connection density is unable to explain any significant portion of the differences in gas companies' efficiencies or the differences between their predicted and actual costs, i.e. that connection density is not a regional difference for gas companies.

Conclusion

Our analysis of the literature on the relationship between connection density indicates that it remains an empirical question whether any relationship exists between these variables in the Netherlands.

We have investigated whether this relationship exists in The Netherlands. Our statistical analysis does not indicate a robust causal relationship between connection density and costs. We found only one significant relationship in the analysis, out of the thirteen tested (considering both electricity and gas). Even in the statistically significant regressions, the estimated coefficients are too imprecise to allow us to determine with sufficient accuracy the magnitude of any effect of connection density on costs. The only regressions that give statistically significant coefficients on the connection density variable involve connection density calculated as connections/km2 ("Measure A"), whose relationship to costs has little theoretical support.

We are also concerned that there is a group of electricity companies with roughly the same costs but very different connection densities and another group of electricity companies with roughly the same connection density but different costs. This implies that an additional variable – management discretion/inefficiency – could explain at least part of the differences between the companies' net SC/CO and connection density.

Consequently, we do not consider connection density to be, for either gas or electricity companies, a regional difference for which allowance should be made in the tariffs.

We explained previously that Essent's reported 2000 standardised costs for electricity may represent an overestimate of Essent's actual standardised costs. We use 2000 standardised costs in our connection density analysis. However, we do not believe that using Essent's (possibly incorrect) data in our analysis will have affected our conclusions. Since Essent's 2000 costs for electricity contain some "fictitious" costs, they overstate the true costs. However, Essent has low connection density. Consequently, using Essent's fictitious (i.e. higher) costs in the analysis will have helped create the appearance of a significant correlation between costs and connection density. Therefore, if we were able to use data that did not include these "fictitious" costs, the results would show an even weaker relationship between costs and connection density.

4.6 Conclusions

Based on our analysis of the available data, we have determined that only taxes (for electricity and gas companies) and water crossings (for electricity companies only) are significant regional differences. For all the other factors, we have either rejected them for not being substantial, or have been unable to measure them reliably. As a result, we would not recommend that any of these other factors provide the basis for prospective tariff adjustments.

5 Final Results

Regional Difference Costs

We have determined for the companies the following regional difference costs. We present the regional difference costs as an amount per year expressed in 2006 €. We use the inflation rates assumed by DTe. We show the regional costs in two different cases: a) when taxes paid to shareholders are not included, b) when taxes paid to shareholders are included. The taxes we show include both sufferance and precario.

It should be noted that the current (efficient) tariff already includes some compensation for taxes. For example, the data for ONS show that ONS paid a significant amount of taxes in 2000. The same holds for the 2001 efficient gas companies Haarlemmermeer, CONET, Obragas, ONS and Westland.

Table 34: Regional Difference Costs for Gas Companies (excl. taxes paid to shareholders)

	Avg taxes 2000-3 (2006 €)	Other regional difference costs 2000-3 (2006 €)	Total regional difference costs (2006 €)
B.V. Netbeheer Haarlemmermeer	-		-
DELTA Netwerkbedrijf B.V.	266,182		266,182
Eneco Netbeheer B.V.	6,046,939		6,046,939
Total Essent Group	-		-
Intergas Netbeheer B.V.	2,350,394		2,350,394
Netbeheerder Centraal Overijssel B.V.	-		-
NRE Netwerk B.V.	-		-
NV Continuon Netbeheer	-		-
Obragas Net N.V.	-		-
ONS Netbeheer B.V.	-		-
RENDO Netbeheer B.V.	1,788		1,788
Westland Energie Infrastructuur B.V.	3,550		3,550
Total	8,668,852		8,668,852

Note: taxes do not include taxes paid to shareholders.

Table 35: Regional Difference Costs for Electricity Companies (excl. taxes paid to shareholders)

	Avg taxes 2000-3 (2006 €)	Incremental water crossings costs 2000-3 (2006 €)	Other regional difference costs 2000-3 (2006 €)	Total regional difference costs (2006 €)
DELTA Netwerkbedrijf B.V.	432,898	2,748,959		3,181,857
Eneco Netbeheer B.V.	6,814,941			6,814,941
Total Essent Group	-			-
Netbeheerder Centraal Overijssel B.V.	-			-
NRE Netwerk B.V.	-			-
NV Continuon Netbeheer	-			-
ONS Netbeheer B.V.	-			-
RENDO Netbeheer B.V.	21			21
Tennet B.V	-			-
Westland Energie Infrastructuur B.V.	5,325			5,325
Total	7,253,186	2,748,959		10,002,144

Note: taxes do not include taxes paid to shareholders.

Table 36: Regional Difference Costs for Gas Companies (incl. taxes paid to shareholders)

	Avg taxes 2000-3 (2006 €)	Other regional difference costs 2000-3 (2006 €)	Total regional difference costs (2006 €)
B.V. Netbeheer Haarlemmermeer	-		-
DELTA Netwerkbedrijf B.V.	266,182		266,182
Eneco Netbeheer B.V.	11,287,526		11,287,526
Total Essent Group	1,304,722		1,304,722
Intergas Netbeheer B.V.	3,196,375		3,196,375
Netbeheerder Centraal Overijssel B.V.	1,398,607		1,398,607
NRE Netwerk B.V.	-		-
NV Continuon Netbeheer	-		-
Obragas Net N.V.	-		-
ONS Netbeheer B.V.	350,372		350,372
RENDO Netbeheer B.V.	4,493,641		4,493,641
Westland Energie Infrastructuur B.V.	3,550		3,550
Total	22,300,977		22,300,977

Note: taxes include taxes paid to shareholders.

Table 37: Regional Difference Costs for Electricity Companies (incl. taxes paid to shareholders)

	Avg taxes 2000-3 (2006 €)	Incremental water crossings costs 2000-3 (2006 €)	Other regional difference costs 2000-3 (2006 €)	Total regional difference costs (2006 €)
DELTA Netwerkbedrijf B.V.	432,898	2,748,959		3,181,857
Eneco Netbeheer B.V.	12,787,201			12,787,201
Total Essent Group	1,616,029			1,616,029
Netbeheerder Centraal Overijssel B.V.	1,395,294			1,395,294
NRE Netwerk B.V.	-			-
NV Continuon Netbeheer	-			-
ONS Netbeheer B.V.	760,624			760,624
RENDO Netbeheer B.V.	1,313,089			1,313,089
Tennet B.V	5,598			5,598
Westland Energie Infrastructuur B.V.	5,325			5,325
Total	18,316,057	2,748,959		21,065,016

Note: taxes include taxes paid to shareholders.

We also break the electricity networks' regional difference costs down by voltage. The companies provided separate cost data for water crossings of <110kV and of ≥110kV. We use this information to break down into voltage levels the regional difference costs related to water crossings. We allocate taxes into the different voltage categories by assuming that the break down is the same as that of companies' composite output. Table 38 shows the breakdown of unadjusted composite output. It is based on information DTe provided, for each network company, on the composite output for consumers at each voltage level.

Table 38: Breakdown of Composite Output by Voltage

	Unadjusted Composite Output for <110kV Network as % of Total
DELTA Netwerkbedrijf B.V.	81%
Eneco Netbeheer B.V.	100%
Total Essent Group	98%
Netbeheerder Centraal Overijssel B.V.	100%
NRE Netwerk B.V.	100%
NV Continuon Netbeheer	99%
ONS Netbeheer B.V.	100%
RENDO Netbeheer B.V.	100%
Tennet B.V	88%
Westland Energie Infrastructuur B.V.	100%

Table 39: Regional Difference Costs for Electricity Companies (breakdown by voltage level; excl. taxes paid to shareholders)

	Avg taxes 2000-3 (2006 €)	Incremental water crossings costs 2000-3 (2006 €)	Other regional difference costs 2000-3 (2006 €)	Total regional difference costs (2006 €)
<110kV Network				
DELTA Netwerkbedrijf B.V.	349,870	535,918	-	885,788
Eneco Netbeheer B.V.	6,799,082		-	6,799,082
Total Essent Group	-		-	-
Netbeheerder Centraal Overijssel B.V.	-		-	-
NRE Netwerk B.V.	-		-	-
NV Continuon Netbeheer	-		-	-
ONS Netbeheer B.V.	-		-	-
RENDO Netbeheer B.V.	21		-	21
Tennet B.V	-		-	-
Westland Energie Infrastructuur B.V.	5,325		-	5,325
Subtotal	7,154,298	535,918	-	7,690,217
>=110kV Network				
DELTA Netwerkbedrijf B.V.	83,029	2,213,040	-	2,296,069
Eneco Netbeheer B.V.	15,859		-	15,859
Total Essent Group	-		-	-
Netbeheerder Centraal Overijssel B.V.	-		-	-
NRE Netwerk B.V.	-		-	-
NV Continuon Netbeheer	-		-	-
ONS Netbeheer B.V.	-		-	-
RENDO Netbeheer B.V.	-		-	-
Tennet B.V	-		-	-
Westland Energie Infrastructuur B.V.	-		-	-
Subtotal	98,887	2,213,040	-	2,311,928
TOTAL	**7,253,186**	**2,748,959**	**-**	**10,002,144**

Notes:

Taxes are allocated to the different voltage levels based on the split of composite output shown in Table 38. Taxes do not include taxes paid to shareholders.

Water crossings costs are allocated to the different voltage levels based on the data submitted by the companies and our calculations of incremental costs for the different water crossings.

Table 40: Regional Difference Costs for Electricity Companies (breakdown by voltage level; incl. taxes paid to shareholders)

	Avg taxes 2000-3 (2006 €)	Incremental water crossings costs 2000-3 (2006 €)	Connection density costs 2000-3 (2006 €)	Total regional difference costs (2006 €)
<u><110kV Network</u>				
DELTA Netwerkbedrijf B.V.	349,870	535,918	-	885,788
Eneco Netbeheer B.V.	12,757,445		-	12,757,445
Total Essent Group	1,589,370		-	1,589,370
Netbeheerder Centraal Overijssel B.V.	1,395,294		-	1,395,294
NRE Netwerk B.V.	-		-	-
NV Continuon Netbeheer	-		-	-
ONS Netbeheer B.V.	760,624		-	760,624
RENDO Netbeheer B.V.	1,313,089		-	1,313,089
Tennet B.V	4,910		-	4,910
Westland Energie Infrastructuur B.V.	5,325		-	5,325
Subtotal	18,175,926	535,918	-	18,711,844
<u>>=110kV Network</u>				
DELTA Netwerkbedrijf B.V.	83,029	2,213,040	-	2,296,069
Eneco Netbeheer B.V.	29,756		-	29,756
Total Essent Group	26,658		-	26,658
Netbeheerder Centraal Overijssel B.V.	-		-	-
NRE Netwerk B.V.	-		-	-
NV Continuon Netbeheer	-		-	-
ONS Netbeheer B.V.	-		-	-
RENDO Netbeheer B.V.	-		-	-
Tennet B.V	688		-	688
Westland Energie Infrastructuur B.V.	-		-	-
Subtotal	140,131	2,213,040	-	2,353,171
TOTAL	**18,316,057**	**2,748,959**	**-**	**21,065,016**

Notes:

Taxes are allocated to the different voltage levels based on the split of composite output shown in Table 38. Taxes include taxes paid to shareholders.

Water crossings costs are allocated to the different voltage levels based on the data submitted by the companies and our calculations of incremental costs for the different water crossings.

Appendix I: Cut-Off Level for a Regional Difference to be Substantial

Below we explain the two main factors that led us to choose 1% as the cut-off for a regional difference to be substantial.

First, in our experience no one can measure efficient costs accurately within 1%, because the boundary between management discretion and an external factor is never absolute, and because luck can affect results. Municipal governments may compel companies to divert pipes or cables to accommodate road diversion. However, management discretion must play at least some role in explaining the variation in costs incurred by the companies in response to road diversions. Even if all companies had to undertake the same level of effort responding to road diversions (in proportion to standardised costs), we would expect to see a variation in the costs, with the most efficient companies spending less, and the less efficient ones spending more. Luck can also play a role. Some companies may face accidents or surprises that raise costs relative to other companies, despite equal efficiency. If the total costs of road diversion are small in relation to composite output, then it becomes quite difficult to determine which portion of the observed variation among companies reflects differences in the proportionate amount of road diversion activity, and which portion reflects differences in efficiency or luck.

Contamination by management discretion or luck is a serious risk for costs that are small as a percentage of composite output. 1% of standardised costs can be as little as €100,000 for the smallest companies. Experience tells us that just one or a few road diversion projects could cost this much. For an extremely small company that handled just one or a few road diversion projects, mismanagement could conceivably produce significant percentage cost overruns on one or two projects, which would distort its total percentage significantly. Similarly, good luck with a low-bidding independent contractor could lead a small company to report unusually small road diversion costs as a percentage of composite output. The factors of luck may tend to balance out for a larger company, but management discretion will still play a role, and if we compare a big company to a small company, and we look at levels of costs that are extremely small, we cannot be confident that the percentage differences reflect underlying differences in the level of road diversion activity imposed by the municipal governments, as opposed to management discretion or good luck or bad luck. Management discretion and luck can even affect taxes, as property taxes can depend on assessed values that management can debate and protest, and that are ultimately uncertain, and sufferance taxes can depend on negotiations with municipal governments.

Imposing a percentage threshold for significance is reasonable, permitting us to accept potential regional differences without being so strict as to exclude everything because in theory management discretion can affect all activities incurred by a company. Imposing a percentage threshold for significance also allows us to avoid the danger of luck exerting a strong influence on the results.

Second, our analysis seeks to determine the potential basis for adjusting tariffs prospectively. Tariff adjustments will inevitably entail inaccuracies. If we raise a company's tariffs by 1%, we cannot be sure that the resulting revenue will increase by 1%, because uncertainties exist concerning the level of customer demand. The problem with accuracy becomes more acute for potentially small tariff adjustments. To illustrate, consider Continuon's proposal to use a cut-off of 0.1%. Conceivably an analysis could conclude that company X deserved an increase of 0.1%. To fund this increase from ten other companies of equal size would require them each to reduce their tariffs by 0.01%. If company X was itself only half the size of the average company in the Netherlands, then funding its 0.1% of standardised costs from ten other companies would require them to reduce tariffs by only 0.005%. The tariffs will themselves depend on forecast demand, and experience tells us that no one is able to predict actual tariff revenues accurately to such small percentages. No one can have confidence that company X in this example will actually receive the intended compensation with any degree of accuracy, or that the other companies will bear the burden equally, as differences in the accuracy of their revenue forecasts will affect the results. For potentially small tariff adjustments, the only way to ensure accuracy of payment and collection is to set up a complex series of accounts that track the predicted impact of tariff adjustments and the actual discrepancies between actual and forecast tariff revenues, rolling the mis-estimates forward over time with interest. However, such a regime would impose a large administrative burden, and would raise difficult questions concerning the desirability of protecting companies from all risks of forecasting errors.

Appendix II: Discussion of Connection Density Literature

A large body of literature suggests that higher connection density and/or population density helps reduce the costs and/or improve the efficiency of a network company. We agree that in theory higher connection density should permit a company to have lower costs per composite output. At the outset of this engagement we said that we suspected such a relationship, and were accused of bias to finding such a relationship. However, we have tested the relationship to the best of our ability and have not derived meaningful results. The strong theoretical reasons to suspect a relationship, and the empirical evidence elsewhere are not sufficient to ignore the absence of any clear statistical relationship in the Netherlands.

Engineering studies support a relationship between density and costs. For example, Essent has submitted a presentation by a professor at Eindhoven University of Technology, which claims that the length of a network is inversely proportional to the square root of the population density.[11] Essent asserts that this relationship causes capex and opex per customer to be higher in rural networks. We consider it inappropriate to base any recommendations on these results. We are concerned that purely engineering studies fail to consider other factors that may cause some of the costs of densely populated (urban) networks to be greater than those of rural networks.

Some studies have documented the possibility of significantly higher costs for urban networks despite their high connection density. Discussing evidence in the United States, Pfeifenberger and Jenkins claim that "the costs disadvantage faced by utilities serving our large cities is quite pronounced."[12] The authors acknowledge that low density and other factors may increase the costs of serving rural areas, but cite several factors that tend to work in the opposite direction. These factors include higher taxes, higher labour costs and the high costs of underground distribution lines. IBC also admits that costs may be higher for rural networks due to the need for a greater length of network cable per customer. However, IBC's experience suggests that this effect may be counteracted by the lower construction cost per km in rural areas. IBC's site visits also indicated that construction methods differed between rural and urban areas in the Netherlands, and IBC believes that rural areas may enjoy some benefits of lower costs.

A recent paper by Benchmark Economics on the costs incurred by Australian electricity distribution companies finds that both operating and capital costs per km of network length are higher for companies with higher connection densities.[13]

Some studies on connection density attempt to control for the multiple factors that may vary between urban and rural areas. For example, Filippini and Wild attempt to explain the costs per

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[11] Mr. Wynia's presentation submitted as part of Essent's response to our draft report.

[12] Pfeifenberger, J.P. and Jenkins, M.W., "Big City Bias: The Problem with Simple Rate Comparisons", *Public Utilities Fortnightly*, December 2002, p.38.

[13] Benchmark Economics, "Western Power: Network Cost Analysis & Efficiency Indicators – Volume I Final Report", June 2005.

kWh of output of the Swiss electricity distribution companies.[14] The authors investigate the role of several variables in explaining average costs. The authors consider a regression equation consisting of several variables including customer density (customers per hectare), customer density squared, the price of labour and the price of capital. The authors find that the price of capital and the price of labour have a statistically significant positive influence on costs per kWh. Research suggests that the prices of labour and capital tend to be higher in urban areas. Therefore, these results may suggest that for some items, electricity companies in urban areas may have higher costs than those in rural areas. The paper also finds that customer density is negatively related to costs and that customer density squared is positively related to costs.

Depending on the actual values of customer density and the prices of capital and labour, statistical analysis involving these variables could produce three types of result: 1) the customer density effects could dominate, 2) the higher wages and capital costs of urban areas could dominate, or 3) the two effects could offset each other. Filippini and Wild's results demonstrate the possibility for the effects to cancel out. The study showed that the coefficients on the variables were as follows: Customer density: -0.3782, customer density^2: 0.0076, price of labour: 0.008, price of capital: 0.0409. A hypothetical company with median values for each of the variables from Filippini and Wild's data set would face the following effects:

Customer density effect: 19.51 x -0.3782 + 19.51^2 x 0.0076 = -4.49

Combined effect of price of labour and capital: 97 x 0.008 + 88.1 x 0.0409 = 4.38

Combined effect of customer density, price of labour and price of capital: -4.49 + 4.38 = -0.11

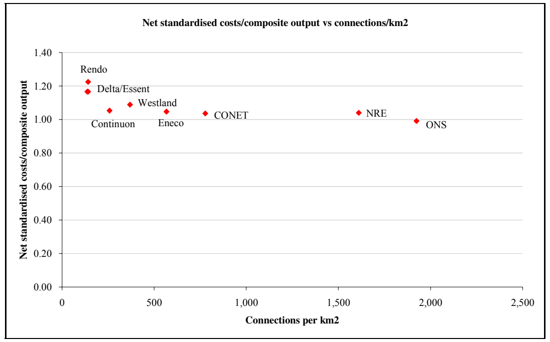
At the margin for the hypothetical median company, more customer density would reduce costs by about the same amount that costs would rise by having the higher prices for labour and capital associated with the next most expensive area of Switzerland. These results suggest that the higher urban costs of labour and capital largely cancel out the cost advantage arising from higher customer density. There is only one way to test which effect dominates in the Netherlands: analyse the data. Filippini and Wild may have found a negative relationship between customer density and costs because they were able to control for other factors such as the price of labour and capital. Unfortunately, it is not feasible to isolate the potential effects of connection density in the Netherlands by adding other variables that may capture the cost disadvantages of large cities. The data sample is too small to include connection density and population density simultaneously in an equation, and to start adding more independent variables such as the potential wage differences among cities in the Netherlands. Our insignificant results for most of

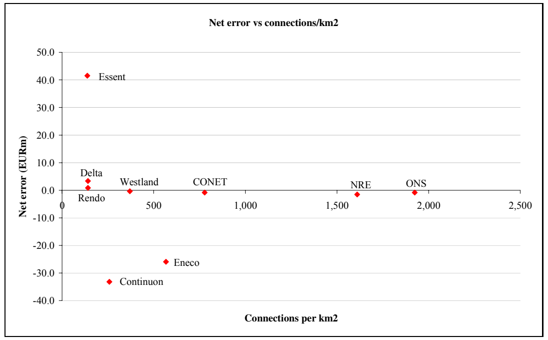
[14] Filippini, M. and Wild, J. of Centre for Energy Policy and Economics, Swiss Federal Institutes of Technology, "Regional Differences in Electricity Distribution Costs and their Consequences for Yardstick Regulation of Access Prices", paper presented at the 6th Regional Science Association International World Congress 2000, Lugano, Switzerland, May 16-20, 2000.

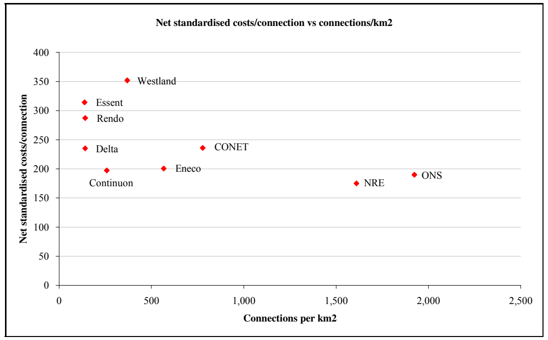
the relatively simple regressions may simply indicate that the two effects of connection density and urbanisation largely offset each other in the Netherlands.

Appendix III: Connection Density Graphs

Connection Density Measure A: connections per km2







Connection Density Measure B: connections per km