INVESTIGATION OF OPERATIONAL COSTS OF DUTCH DISTRIBUTION NETWORK OPERATORS

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1 Introduction and Summary

The fourth regulation period for Dutch gas distribution network operators (DNOs) and the fifth regulation period for Dutch electricity DNOs will start on 1 January 2011. In preparation the Dutch Office of Energy Regulation (*Energiekamer* or EK) has collected data on DNOs' costs and service volumes. The data shows that, after a period of reducing operating costs (OPEX), OPEX recently seems to have adopted an upward trend, despite continuing regulatory incentives to reduce OPEX.

EK has commissioned The Brattle Group to analyse the OPEX data, and explain what factors have led to an increase in OPEX. Note that it is not the intention of this exercise to 'audit' the OPEX costs, validate explanations given by the DNOs or perform a rigorous benchmarking exercise.

EK has supplied us with 'CODATA' data sets for three of the largest DNOs: Liander, Stedin and Enexis. The DNOs supply this cost data – which is audited – to EK as part of the price control exercise. We have analysed the DNOs' cost data to identify underlying trends and questions, which we have put to the DNOs in a series of face-to-face interviews.

We have analysed gas and electricity costs separately for each DNO. However, almost all costs are common to electricity and gas, and DNOs must allocate these costs using subjective allocation 'keys'. We also consider where changes in allocation of costs between electricity and gas could have caused a decrease in one set of costs and an increase in another.

Over the past three years, gas network operating costs have remained broadly constant in real per customer terms. Since 2006, Liander has achieved a 1.2% decline in real per customer operating costs year-on-year. Stedin saw a modest 0.6% year-on-year rise over the same period; while Enexis saw a substantial real terms decline between 2007 and 2009.[1] In contrast, electricity network operating costs have risen sharply since 2006. Liander has seen electricity network operating costs increase by over 8% per year. Stedin witnessed a comparable increase of roughly 5% year-on-year. Enexis is the exception, achieving 1.5% year-on-year real per customer savings over the three year period between 2006 and 2009. Figure 1 and Figure 2 illustrate the development of real per customer costs over time.

[1] Enexis disputes the 2006 cost figure contained in the CODATA sheets.

Figure 1: Gas operating costs 2006 - 2009

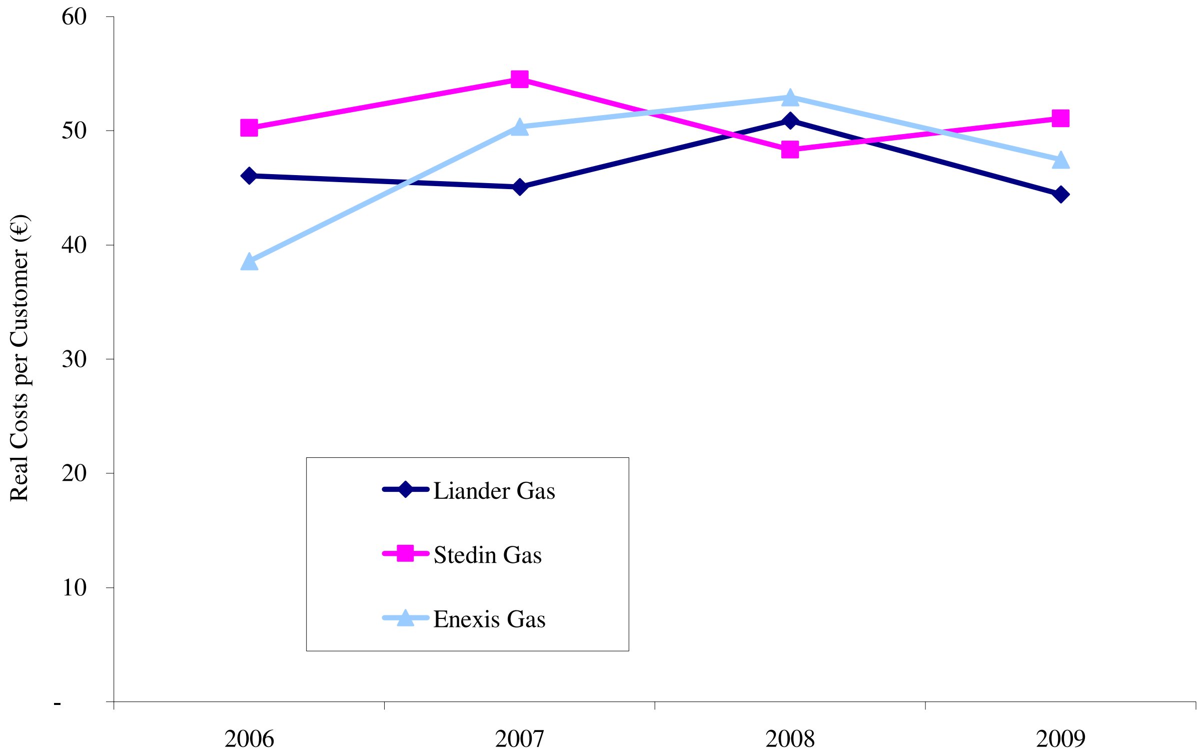
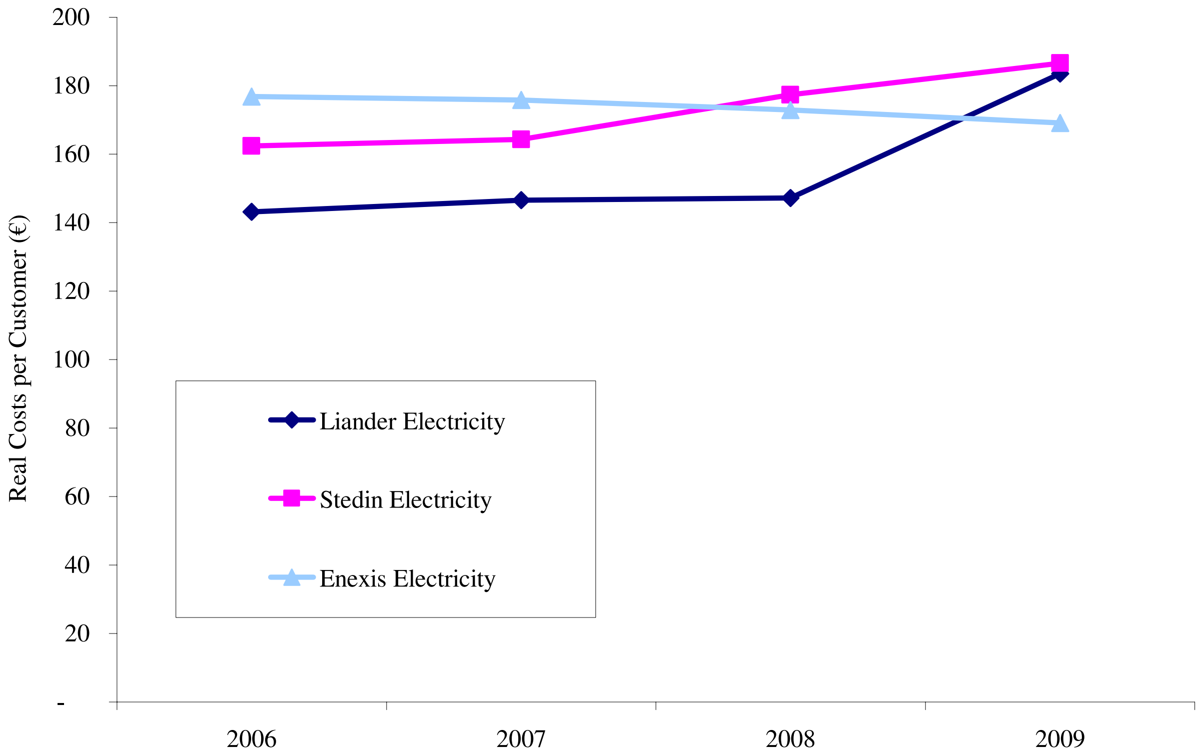


Figure 2: Electricity operating costs 2006-2009



All of the DNOs identified several common factors which have a large effect on OPEX:

- Change from a 'thin' to a 'broad' DNO, whereby DNOs had to assume ownership of assets, unbundling, and the implementation of the 'market model'. These factors prompted a re-organisation which generally increased OPEX costs. While the costs of unbundling were not included in OPEX, unbundling required that several functions that were previously carried out at a corporate level and shared with the associated supply business now had to be brought in house. For example DNOs set up in house treasury, risk management, public affairs/communications, building/facilities, catering audit and communications functions. DNOs explained that because unbundling created a loss of synergy in, for example, the public affairs department, costs had generally increased relative to the previous situation where functions were 'subcontracted' from the corporate centre. As functions are brought in-house, DNOs have seen a rise in personnel costs along with a corresponding fall in subcontracting costs. The two have more-or-less balanced each other out for the gas networks, while the net effect for electricity has been a significant increase in costs. The increase in personnel and subcontracting at Liander's electricity network is significantly larger than anywhere else, with an impact of close to €100 million since 2006. For their part, Stedin and Enexis both incurred roughly €30 million of extra costs relating to unbundling and the market model.[2] DNOs also seem to have used the restructuring required by unbundling to implement improved IT systems, staff training and customer quality programs.

- Selling of the High Voltage (HV) grid to TenneT. DNOs have sold or are in the process of selling off their HV grids to TenneT, although for Liander and Stedin the presence of Cross Border Leases (CBLs) on parts of the HV grid has complicated this process. Nevertheless, the sale of the HV grid explains some of the changes in transport cost and costs of losses that we see in the OPEX data.

- Growth in distributed electricity generation, especially in 2007 and 2008. Enexis and Stedin in particular experienced a large increase in the number of new connections as a result of new distributed generation. Liander's connection rates remained constant, but it claimed that they nevertheless made substantial investments in the network to accommodate future growth in distributed generation and extra demand from new sources such as heat pumps and electric cars. Liander and Stedin claimed that these investments had spillover effects which increased OPEX, although the precise magnitude of these effects was unknown. Enexis did not think that there would be much spillover.

- Re-allocation of costs between gas and electricity networks. DNOs told us that the re-organisations had given clearer insights into how the costs of some activities should be allocated. Some of these re-allocations could be quite substantial – for example in 2009

[2] Enexis actually incurred costs in 2010, but set aside money in both 2008 and 2009. €30 million is roughly the total amount of the money set aside by Enexis in 2008 and 2009 to cover unbundling and market model costs at the electricity network.

Liander moved €16.5 million of costs from gas to electricity due to a change in the allocation 'key'.

We find it notable that none of the DNOs mentioned the recent financial crisis explicitly as a source of OPEX increases. This is probably because even if volumes have fallen, the number of customers and connections has stayed constant or even risen. Also the DNOs explained that their OPEX was not sensitive to volumes. Moreover, we do find indirect evidence that the downturn in economic activity explains some of the observed trends. For example DNOs who bought power forward in 2008 were subsequently 'surprised' by the fall in APX prices in 2009, which left their power purchases looking expensive. TenneT overestimated volumes in 2009, which means that its 2009 tariffs are 'too low' and will have to rise in 2010 to compensate. DNOs with CBLs reported that they had to post extra collateral against the leases, and that the financial crisis probably triggered this requirement. There were slight increases in bad-debt provisions, but nothing significant.

Liander also mentioned that, because their shareholders are municipalities, their primary objective is not always to maximise profits, but also to perform other social or environmental functions. For example, a municipally owned DNO may invest in higher levels of service than a private firm would, because the municipality thinks this is optimal. The DNOs implicitly acknowledged that they do not always respond to the RPI-X incentives in the same way that a profit maximising privately owned firm might do. This is just as true in 2006 and 2009, and so cannot be the whole answer to the observed increase in OPEX. But it seemed that some DNOs saw the re-organisation as an opportunity to invest in programs which they saw as socially beneficial. Accordingly, it would be fair to say that some DNOs reacted differently to the re-organisation than a purely profit maximising firm would have done, and this partially explains the observed increases in OPEX.

The cost of buying power to cover losses varies in ways that are hard to explain. We understand that the DNOs manage the price-risk associated with losses by buying the majority of their power in advance or via indexed contracts. Only a relatively small amount of power is bought at APX prices. Nevertheless, some DNOs show a steadily increasing price of losses which is hard to explain. It seems that, whatever the purchasing arrangements for losses, the DNOs have failed to 'beat' or even match the cost trend of the APX on average between 2006 and 2009.

We also note that there seems to be some discretion concerning the amount of investment that can be recorded as operating costs. Stedin told us that 10% of capital costs were routinely recorded as OPEX, whereas Enexis capitalised 100% of the costs of their investments between 2006 and 2009. The reasons for the differences seemed to be purely a matter of company preference and perhaps resulted from differing accounting advice. This different in accounting treatment creates difficulties in comparing across DNOs. While this difference in accounting treatment might have been minor in the past, recently DNOs have invested more heavily in CAPEX due to new connections, changes due to restructuring and replacement of ageing networks. The heavy CAPEX investment may have prompted some difference in OPEX between DNOs due to distinct accounting policies. It is notable that the DNO with the smallest OPEX increases – Enexis – is the DNO which capitalises 100% of investment costs.

Conclusions

As discussed above, there seems to have been a number of extraordinary events – unbundling, transfer of HV grids, growth in distributed generation – that can at least partially and qualitatively explain some of the observed increases in DNO OPEX. It seems that DNOs have used the unbundling/re-organisation to make investments that should make them more efficiency and set OPEX costs on a downward trend in future.

As part of its future work in this area, we recommend that EK should consider:

- Imposing stricter guidelines on the allocation of costs between gas and electricity networks;
- Requiring uniform accounting treatment for the DNOs in the allocation of capital-project costs to OPEX;
- Providing guidelines on the procurement of power for losses, in particular ensuring that the power is provided for by competitive tender and that there is an appropriate trade-off between risk reduction and value for money.

2 Process of the Research

The bulk of the research work took place over a relatively compressed time frame starting on 28th June 2010 and ending 19th July 2010. Given the limited time frame, we agreed with EK to analyze the cost data of only the three largest DNOs – these DNOs were Liander, Stedin and Enexis. It was felt that analyzing the three largest DNOs would enable us to analyze the costs which affect the vast majority of customers in the Netherlands.

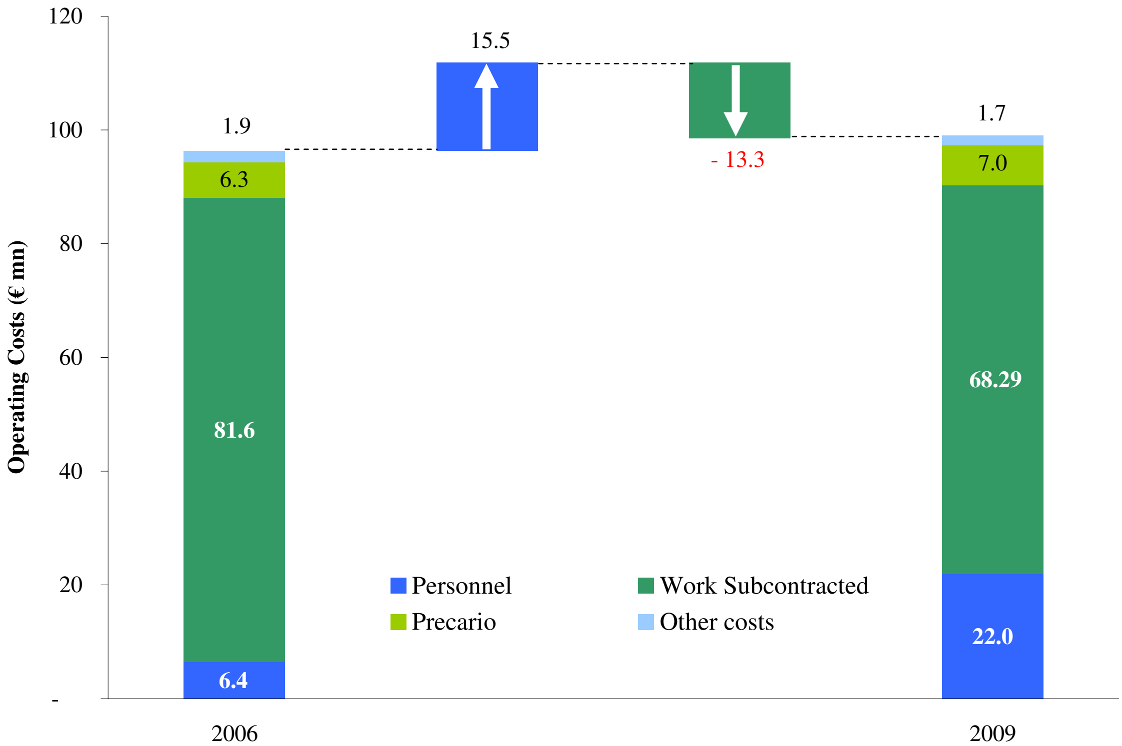
At the beginning of the project EK sent us CODATA cost data covering the period 2006 to 2009 inclusive. We undertook an initial analysis of this data, for example examining how different cost elements changed over time and the extent to which external factors could explain the changes. Also at the beginning of the project, we contacted the DNOs and arranged interviews for the 8th and 9th of July 2010. Based on our initial analysis of the data we prepared a questionnaire for each DNO which highlighted the main issues that we wanted to discuss in the interviews. The questionnaires were sent to the DNOs a couple of days before the interviews, and it was made clear that the DNOs did not need to prepare anything for the interviews, other than arrange for the relevant staff to be present. Following the interviews, we submitted a draft report to EK on 19th July 2010. We also corresponded with the DNOs with follow-up questions after the interviews. We submitted a further draft report to EK on 2nd August 2010. We submitted the final report to EK on 16th August.

3 Liander

3.1 Gas

The vast majority of the operating costs of the gas network relate to personnel and subcontracting costs. For Liander, the personnel line-item reflects salary and other expenses associated with employees dedicated to the gas network, such as gas technicians. Subcontracting generally relates to other services such as billing, communications, legal, treasury, asset management etc. purchased by the gas network from other entities under the corporate umbrella. Subcontracting costs reflect in part allocations to the gas network of salary and other expenses associated with corporate personnel. Subcontracting also includes amounts paid to third parties. The only other sizeable cost item is precario. It accounted for roughly 6-7% of operating costs between 2006 and 2009. Precario is levied on the gas network by municipalities and the gas network has little control over the level of costs. Figure 3 illustrates the change in operating costs from 2006 to 2009, and highlights the important shifts in the underlying cost components.

Figure 3: Gas network cost development (2006-2009)



In absolute terms, Liander's gas operating costs (excluding connections) have hardly changed, effectively dropping in real terms. Nevertheless, Liander's gas network personnel costs increased sharply between 2007 and 2008, from about €9 to €25 million, before falling back slightly in 2009. The general rise in Dutch wages of 5% since 2006 accounts for only a fraction of this increase. The big increase in personnel costs occurred before the onset of the recent economic crisis, while personnel costs declined somewhat as the recession started to bite.

As personnel costs rose by close to €15 million over the period, subcontracting costs fell by a comparable amount. Rising personnel and falling subcontracting expenses is consistent with the movement of corporate services in house. For example, Liander moved personnel with legal, treasury and finance experience from the corporate holding to the gas and electricity network companies. The overall €15 million rise in personnel costs in 2008 was equivalent to roughly 20% of gas network subcontracting expenses moving in-house.[3] In effect, the total of personnel and subcontracting costs remained broadly flat in absolute terms between 2006 and 2009, effectively reducing in real per customer terms.

Liander explained that unbundling and the change in the market model prompted the corporate re-organisation, and bringing in-house functions such as legal, treasury and other financial activities, communications, billing and IT. Previously the gas network had sub-contracted all these services from other corporate entities. But unbundling and the change in the market model meant that Liander had to, for example, split its billing, customer management and data back-up systems, and create communications and treasury departments at the network company level. The shift of costs from subcontracting to personnel appears permanent, but we note that the overall combination of personnel and subcontracting appears to have declined steadily in real per customer terms, even in 2008 when most of the re-organisation occurred.

Liander said it took the opportunity afforded by re-organisation to invest in new IT systems and architecture. Most of these expenditures were capitalised, but Liander claimed that the new IT systems would have prompted some additional operating costs . For example, Liander said that it hired more people to help operate the new systems. It also expensed any costs associated with training existing staff on the new systems. Liander even claimed that the costs associated with consultants and others hired to design the new IT systems would have appeared in operating costs. Liander could not, however, split-out the impact of any of these activities on operating costs. Other than the need for extra staff, the costs mentioned by Liander appear to be one-offs.

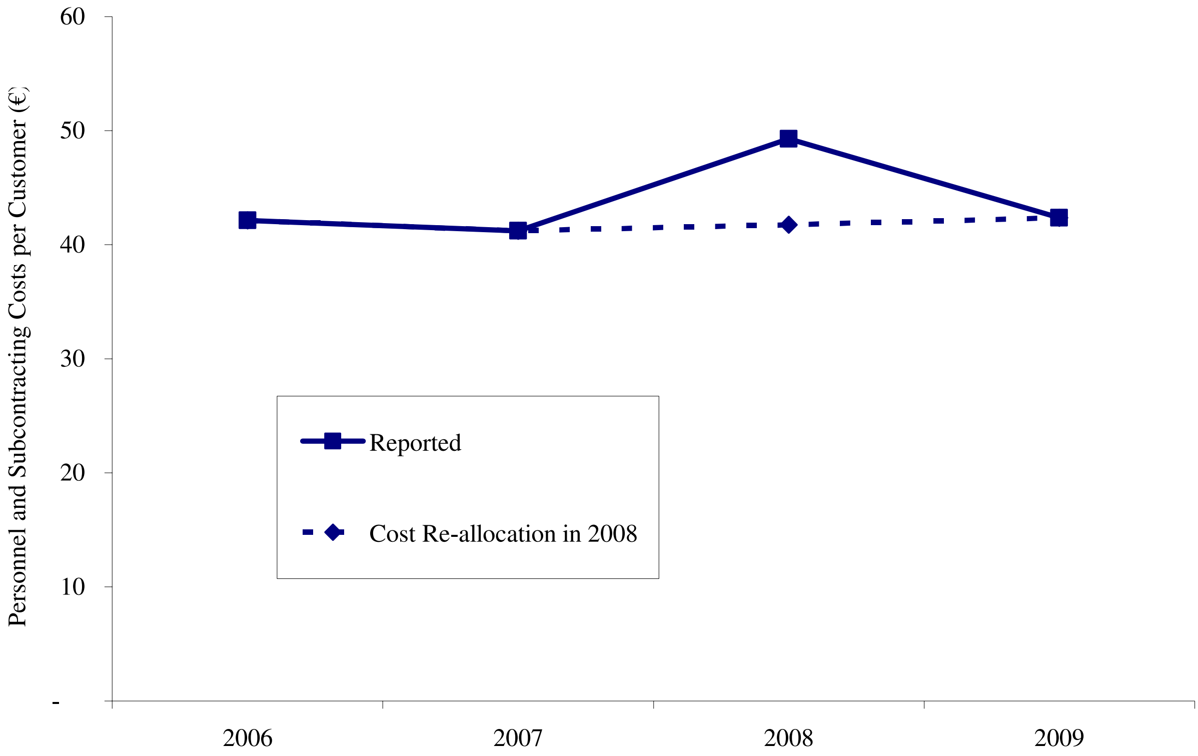
Liander also noted the need for major replacement of ageing grey cast iron pipes. It claimed to have embarked on a fast replacement and refurbishment program, involving substantial capital investment. Although the costs of the program were and are capitalised in large part, Liander thought the investment program also prompted an increase in personnel, with substantial employee time devoted to the investment program. The salary and other associated costs of these staff were expensed and appeared in operating costs. Liander could not split-out the impact of the investment program on operating expenses.

Although the combination of personnel and subcontracting did not rise overall between 2006 and 2009, we observe a peak in 2008. The combination of personnel and subcontracting rises by roughly €18 million in 2008 before falling back by roughly €15 million in 2009, for a net increase of €3 million between 2007 and 2009. Liander explained the peak with reference to a change in the way it allocated costs between the gas and electricity networks. Liander said that it used the same cost allocation keys in 2008 as it had done in 2006 and 2007, but that it changed the allocation keys in 2009. The change of approach reflected an improved understanding of the time devoted by staff to different activities following the 2008 re-organisation. Liander explained that the change in

[3] Liander incurred €78 million of subcontracting expenses in 2007. 20% of the full €78 million of subcontracting expenses equals €15 million.

allocation approach shifted €16.5 million of costs from the gas to electricity network in 2009, or almost all of the apparent increase in personnel and subcontracting in the previous year. In other words, if we applied the 2009 cost allocation back in time, we would presumably strip-out roughly €15-16 million of the reported 2008 operating costs from the gas network. The result would be to flatten the 2008 peak completely, and leave operating costs for the gas network largely unchanged in absolute terms throughout the entire period, on a declining real per customer trend. Figure 4 illustrates the development of personnel and subcontracting over time.

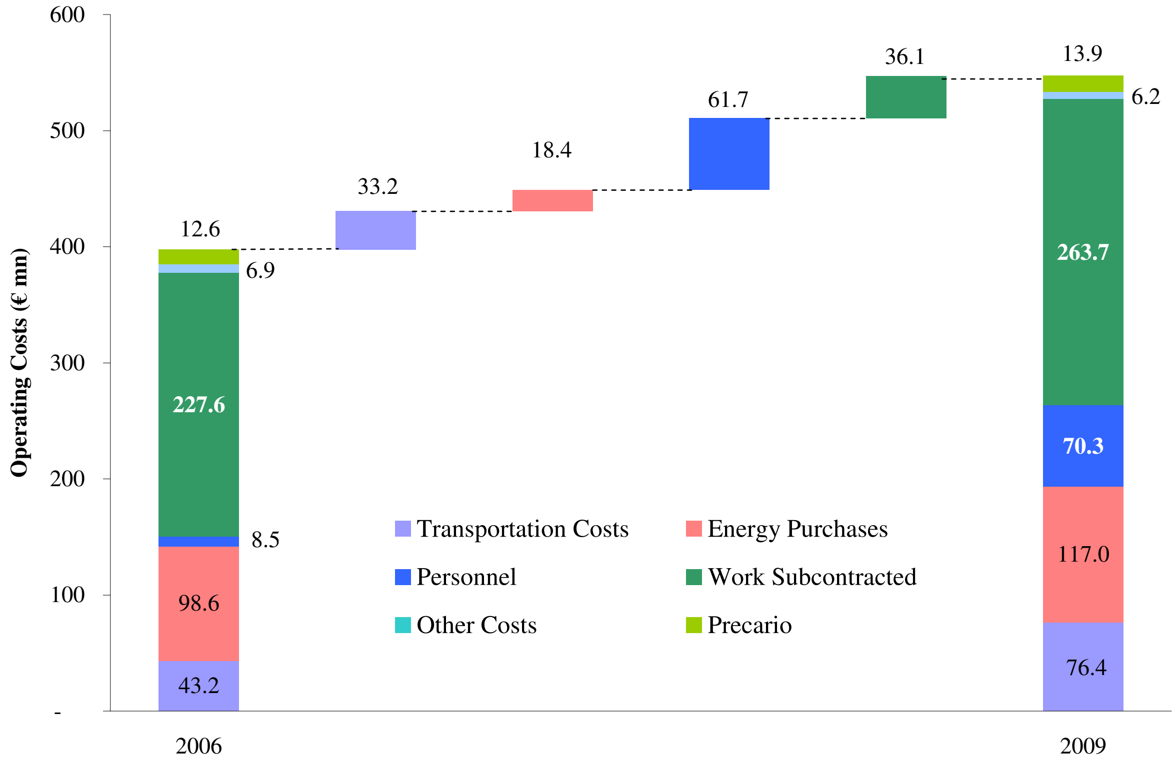
Figure 4: Personnel and subcontracting per customer



3.2 Electricity

Liander breaks out operating costs for the electricity network into four principal cost components: transportation charges paid to TenneT, the cost of energy purchases needed to cover losses, direct personnel expenses and subcontracting. Transportation charges accounted for roughly 10-15% of operating costs throughout 2006 to 2009; energy purchases between 20-30%; and the combination of personnel and subcontracting roughly 60%. Like for the gas network, the only other sizeable cost item is precario, which accounted for as little as 3% of operating costs between 2006 and 2009. Figure 5 illustrates the change in operating costs from 2006 to 2009, and highlights the important shifts in underlying cost components.

Figure 5: Electricity network operating cost development – 2006-2009



Operating costs for the electricity network rose by close to 40% between 2006 and 2009, or by roughly 8% per year. The substantial rise in electricity network operating expenses contrasts the development of Liander's gas network operating costs, which declined in real terms. The overall rise in electricity network operating expenses is not driven by any one of the underlying cost components, but by increases all across the board. Since 2006, Liander has seen a 74% rise in transportation charges, a 65% rise in the cost of purchased power, and close to a 45% rise in the combination of personnel and subcontracting. Only precario remained broadly flat since 2006.[4]

The costs of transporting power over higher voltage (HV) grids display step increases at two separate points in time in. Between 2006 and 2007, transportation costs grew by close to 30%. They then remained roughly flat in 2008, before stepping up again by a further 30% in 2009. The 2006-2007 increase cannot be explained with reference to demand. Liander's annual peak load rose less than 1%.[5] The cost increase appears to reflect an increase in the level of TenneT's annual peak load tariff for ultra high voltage. This tariff accounted for over 75% of Liander's transportation costs in 2006 and 2007. The tariff paid by Liander jumped from 8.97 per contracted kW in 2006 to 12.39 per kW in 2007, equivalent to a 38% increase. None of the other DNOs attributed a rise in transportation costs to such a hike in tariffs.

[4] Although precario doubled from just over €6 million in 2005 to €12.5 million in 2006.

[5] Data provided from Liander. 3,676,661 kW in 2006 to 3,708,060 in 2007.

Interestingly, the rise in the ultra-high voltage tariff between 2006 and 2007 increased Liander's share of TenneT's overall regulated revenues. In 2006, Liander contributed €43 million or just under 12% of TenneT's overall revenue requirement of €367 million. The 2007 rise in the ultra-high voltage tariff precipitated an increase in Liander's contribution to over 15%.[6]

Liander put forward several explanations for the subsequent 2008-2009 increase in transportation costs. Liander provided data indicating that its peak demand on the ultra-high voltage grid increased by close to 9% between 2007 and 2009. We are not sure why Liander saw such an apparent increase in peak demand. Connections activity in the interim was broadly stable. Liander also thought that a further change in TenneT's tariff structure could have contributed to the rise in costs. Prior to 2009, demand from Liander attracted a simple annual peak load tariff for ultra-high voltage. That changed in 2009 to separate tariffs for both ultra-high voltage and high-voltage, and separate tariffs for annual and monthly peaks. Liander also mentioned a third factor: the transfer of HV grids to TenneT.[7] However, Liander was unsure about the separate impact of each factor and said that complicated analysis would be required to find out.

After our meeting, Liander provided more detail of its transportation costs in 2009, showing the development of costs throughout the year. The data indicate that the change in tariff structure did not prompt any significant rise in costs. The sharp rise in transportation costs in 2009 was prompted by a step change in the magnitude and structure of Liander's peak load. For the first five months of the year, Liander's peak load was roughly 3.3 GW on the UHV grid, and 0.43 GW on the HV grid, reflecting a combined peak load across the TenneT network of roughly 3.7 GW. This was broadly where peak load had been in previous years. But for the remaining seven months of the year, peak load on the UHV grid dropped to roughly 0.8 GW, while that on the HV grid rose to 4.2GW, combining for more than 5.0GW overall. Had the structure and magnitude of Liander's peak load remained at the same level as observed during the first five months of the year, Liander's transportation costs would have been roughly the same as in previous years.

[6] Liander reported transportation costs of €55 million, compared with TenneT's 2007 revenue requirement of €360 million.

[7] Although Liander said that it still collects revenues – via TenneT – on the HV grid, and pays for the HV grid operating costs directly.

Table 1: Liander's transportation costs

	Actual 2009	2009 - Extend first 5 months for entire year	Impact of Change in Load Profile
Ultra High Voltage			
Yearly Peak Load (kW)			
5 months	3,269,911	3,269,911	
7 months	787,272		
Amount Contracted (kW)	1,821,705	3,269,911	
Tariff (€/kW)	5.54	5.54	
Costs of Yearly Peak Load (€)	10,092,245	18,115,307	
Monthly Peak Load (kW)	18,757,611	33,669,404	
Tariff (€/kW)	0.51	0.51	
Costs of Monthly Peak Load (€)	9,566,382	17,171,396	
Transport Costs UHV (€)	19,658,627	35,286,703	
High Voltage			
Yearly Peak Load (kW)			
5 months	430,290	430,290	
7 months	4,237,598		
Amount Contracted (kW)	2,651,220	430,290	
Tariff (€/kW)	10.40	10.40	
Costs of Yearly Peak Load (€)	27,572,685	4,475,016	
Monthly Peak Load (kW)	28,686,849	4,655,844	
Tariff (€/kW)	1.04	1.04	
Costs of Monthly Peak Load (€)	29,834,323	4,842,077	
Transport Costs UHV (€)	57,407,007	9,317,093	
Total Transport Costs (excl connections etc) (€)	77,065,634	44,603,796	32,461,838

The transfer of the HV grids to TenneT appears the most plausible explanation for the step change in the magnitude and structure of Liander's peak load and the corresponding increase in transportation costs. The explanation makes sense of timing - Liander's annual report dates the sale of the HV grids as June 1 2009, precisely 5 months into the year.[8] Perhaps electricity generation was attached to the assets transferred to TenneT, so that Liander now has to contract for substantially more 'import' capacity than before at revised network entry-points.[9] Liander indicated that it remained unsure about the balance of production and consumption on the HV grid, but believed such a change could have contributed to the step rise in transportation costs. Interestingly, Liander's 2009 annual report attributes €13 million of the overall 2009 cost increase to the sale of

[8] TenneT paid €368 million for the assets. This level of purchase implies an equivalent annual rental charge for the assets of roughly €30 million (€368 million amortized at 7% over 30 years). 2009 Annual Report p. 53.

[9] Liander also told us that the level of HV peak load for 2009 is still under discussion with TenneT and that the charges rely on approximations because of an inability to perform direct measurements at the new connection points.

HV grids to TenneT.[10] Our Table 1 calculations indicate a €30 million effect associated with the change in the structure and magnitude of the peak load. Whatever the precise cause or causes of the increase in transportation costs, as an overall result, we observe a slight rise in Liander's contribution to TenneT's overall revenue requirement: 13.8% in 2008 versus 15.4% in 2009.

Along with transport costs, Liander's energy purchase costs relating to losses rose from €70 million in 2005 to €125 million in 2008, before declining to €117 million in 2009. Liander explained that the volume of losses declined throughout the period and that it routinely covers the vast majority of losses with power purchased from Nuon under long-term contracts. While we understand that the DNOs do not buy power to cover losses on the Amsterdam Power Exchange (APX), the APX nevertheless serves as a useful price benchmark. Between 2006 and 2009 the average annual electricity price on the APX rose from €50 to €70 per MWh, before falling back to €40 per MWh in 2009. Figure 6 compares Liander's energy purchase costs with APX power prices, and indicates that general price movements cannot explain the overall trend in energy purchase costs.

Figure 6: Energy purchase costs

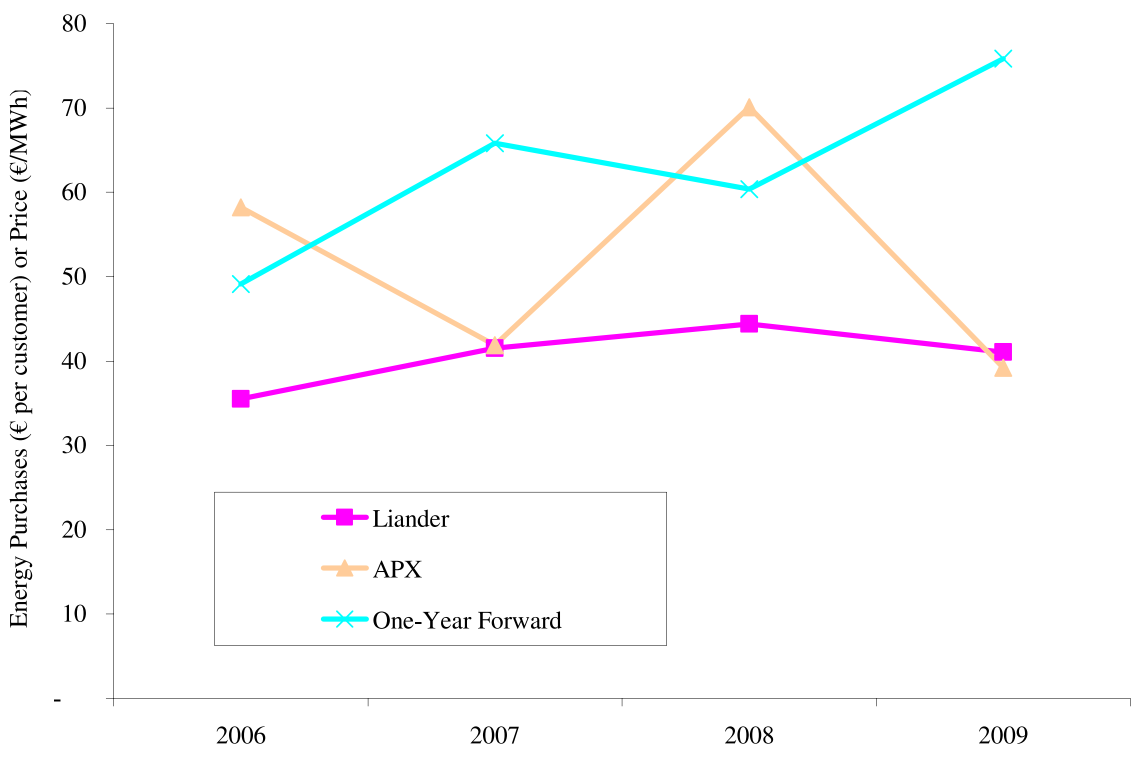


Figure 6 also plots average annual prices for contracts to deliver power one-year in advance, reflecting that Liander prefers to purchase the majority of its power needs under long-term contracts. For ease of comparison, we plot the price of a one-year future at the date of delivery, not at the date when the contract was originally written. For example, Liander could have committed in 2007 to buy baseload power for delivery in 2008. During 2007, the average price for delivery one-

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[10] 2009 Annual Report, p. 56.

year ahead was €60 per MWh. Figure 6 plots the €60 per MWh price at the 2008 delivery date, when the contract ultimately would have been settled. Futures prices displayed marginally less variation over the period than APX spot prices, and they displayed an increasing trend.

Whatever Liander's precise procurement strategy, the prices actually paid do not exactly track either APX or one-year futures prices. Costs rose even while APX prices dropped in 2007, but then dropped somewhat in 2009 as the APX benchmark plummeted. The differences cannot be explained with reference to changes in the volume of losses. Liander said that the volume of losses had not varied significantly over the period, and that, if anything, the volume of losses had declined slightly. Without further research, Liander could not be more specific about the volume of losses over time. If we assume the volume of losses remained constant between 2006 and 2009, Liander's energy purchase costs rose by roughly 20% more than if it had merely bought power on the APX.[11] At the same time, Liander's energy purchase costs rose by about 10% less than they would have had it always purchased power one-year forward.[12]

In 2008, personnel costs for the electricity network jumped from just over €4 per customer to over €20. The jump coincided with similar experience at the gas network. At exactly the same time, personnel costs at the gas network jumped from just over €4 per customer to €11. Also comparable to gas network experience was the countervailing reduction in subcontracting expenses. While personnel costs at the electricity network increased by €40 million, subcontracting costs declined by just over €25 million, resulting in a net gain of €15 million up until 2008. This pattern is again consistent with the movement of various functions in-house as a result of corporate restructuring and the implementation of the market model.[13]

The combination of personnel and subcontracting had been on a downward path prior to 2008. But the 2008 restructuring immediately prompted an increase of roughly €20 million in the combined figure. The increase would have been even greater had Liander adopted the same approach to cost allocation as it did in 2009. Applying the 2009 allocation approach back in time, we might see an additional €15-16 million in electricity network personnel and subcontracting expenses in 2008, on top of the €20 million increase we already see reflected in the CODATA sheets. €35 million or so of extra personnel and subcontracting costs was equivalent to a hike in personnel and subcontracting of 16% in 2008.

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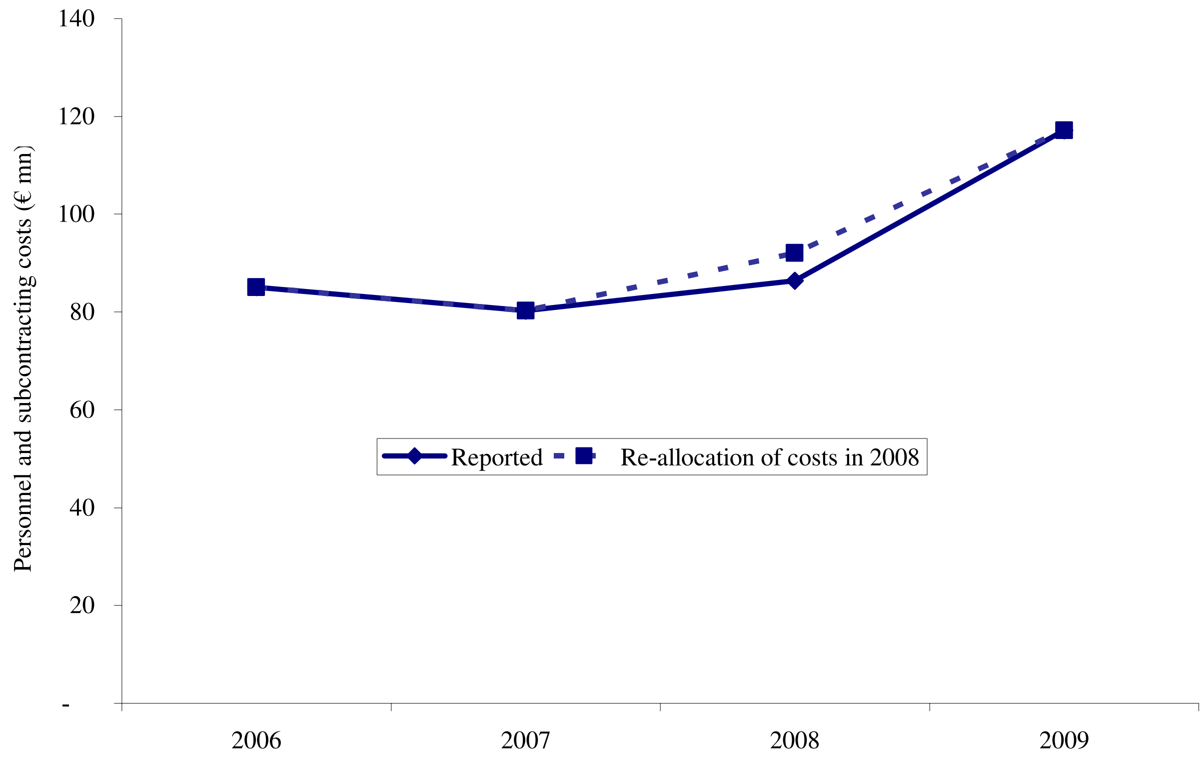
[11] This is not quite the same as saying that Liander overpaid relative to the APX, more that Liander did worse with respect to APX prices over time. Even if it did worse over time, it remains logically possible that Liander may have beaten a "100% from APX" purchase strategy.

[12] This is again not quite the same as saying that Liander underpaid relative to one-year futures, just that Liander did better with respect to one-year forwards over time. For illustration, we calculate the present value of Liander's actual energy purchase costs as of January 2006 - €394 million. We apply a discount rate of 6% to the numbers reported in the CODATA sheets. The discount rate reflects in part the risk associated with power prices. Starting at 2006, we then estimate what Liander's energy purchase costs would have been if the only changes over time related to price movements on the APX. The calculations indicate that Liander paid just over €85 million more in present value terms than suggested by price movements on the APX. We perform a similar analysis using one-year baseload forwards instead of APX prices.

[13] We note that a €40 million rise in personnel costs was equivalent to just over 20% of subcontracting expenses in 2007. The corresponding €15 million rise in gas network personnel also was equivalent to 20% of subcontracting expenses in 2007.

Figure 7: Personnel and subcontracting



As well as bringing important corporate functions in-house, Liander stressed that management saw the re-organisation as an opportunity to invest in upgrading systems, enhancing staff training and investing in innovation. For example, it spent money on programs such as the ‘World Class’ customer service program and on pilot studies examining the impact of more renewable and distributed generation on the operation of the network. Liander claimed that it embarked on many of these activities in part because management felt that they had kept network costs down relative to allowed revenues and that they preferred to re-invest spare cash to improve the long-term performance of the network to the benefit of stakeholders, rather than to pay all available monies out in dividends to shareholders. Management claimed that these forward looking activities inevitably placed upward pressure on operating costs. Unfortunately however, without significant work, Liander told us that it was unable to break out the costs of these various activities or to identify whether in fact these activities contributed the entirety of the €35 million rise in personnel and subcontracting or only a part of the rise.

In essence, the re-organisation appears to have been a catalyst for Liander to take on activities and operating costs beyond what would have been strictly necessary to fully unbundle and move to a broad DNO. Liander felt these “investments” would pay off over time, in terms of enhanced network operations and reduced costs in future. For example, management believed that they could charge some of the additional expenses to new areas of unregulated business, and that this would reduce the operating costs allocated to the regulated business in future. Liander was not specific about what these opportunities were, but perhaps there might be new areas of unregulated business relating to electric cars, heat pumps, load management etc. that could provide some opportunities. Neither was Liander specific about the proportion of the rise in personnel and subcontracting costs related to upgrading systems etc.

The combination of personnel and subcontracting expenses continued its trend upwards in 2009, where it increased by roughly €90 million in absolute terms, equivalent to a 30% rise year-on-year. Of course, €16.5 million of the increase relates to the one-off change in cost allocation approach that we discussed previously.

At our meeting, Liander attributed the remaining €70 million increase to several factors. The first thing it mentioned was that 2009 was the first year that saw the full cost impact of the new IT systems, personnel etc prompted by restructuring. This is somewhat confirmed by Liander's 2009 annual report, which identifies a €29 million structural increase in operating costs and a further €37 million of one-off expenses. The annual report attributes these items to activities and special projects prompted by restructuring.[14]

In addition, at our meeting, Liander thought that part of the rise could relate to its substantial upgrade of the medium voltage network from 10 kV to 20 kV. The investment program was motivated by a desire to accommodate both future distributed generation and increased demand from heat pumps. We were told that the investment program would have had some spillover into operating costs due to the need for additional personnel to manage the program.

However, questions surround the relevance of this last explanation. According to the CODATA sheets, Liander invested as much as €107 million in the electricity network in 2009, with the vast majority of investment relating to the medium voltage network. But the CODATA sheets also indicate that Liander invested just as heavily in previous years. It is therefore unclear why the 2009 investment program could spillover into operating expenses more than those undertaken in previous years. In any event, any spillover into operating expenses is likely to be only a fraction of the total amount invested. If we assume spillover of at most 20% of the face value of the €107 million investment in 2009, we could be talking about at most a €20 million impact on 2009 operating costs. All this implies that the medium voltage investment program can only explain a fraction of the soaring personnel and subcontracting in 2009. We do not know what caused the substantial increase in personnel and subcontracting costs in 2009 but the only credible explanation offered is that it reflects the full realisation of restructuring costs and Liander's improved ability to allocate costs more accurately than before.

4 Stedin

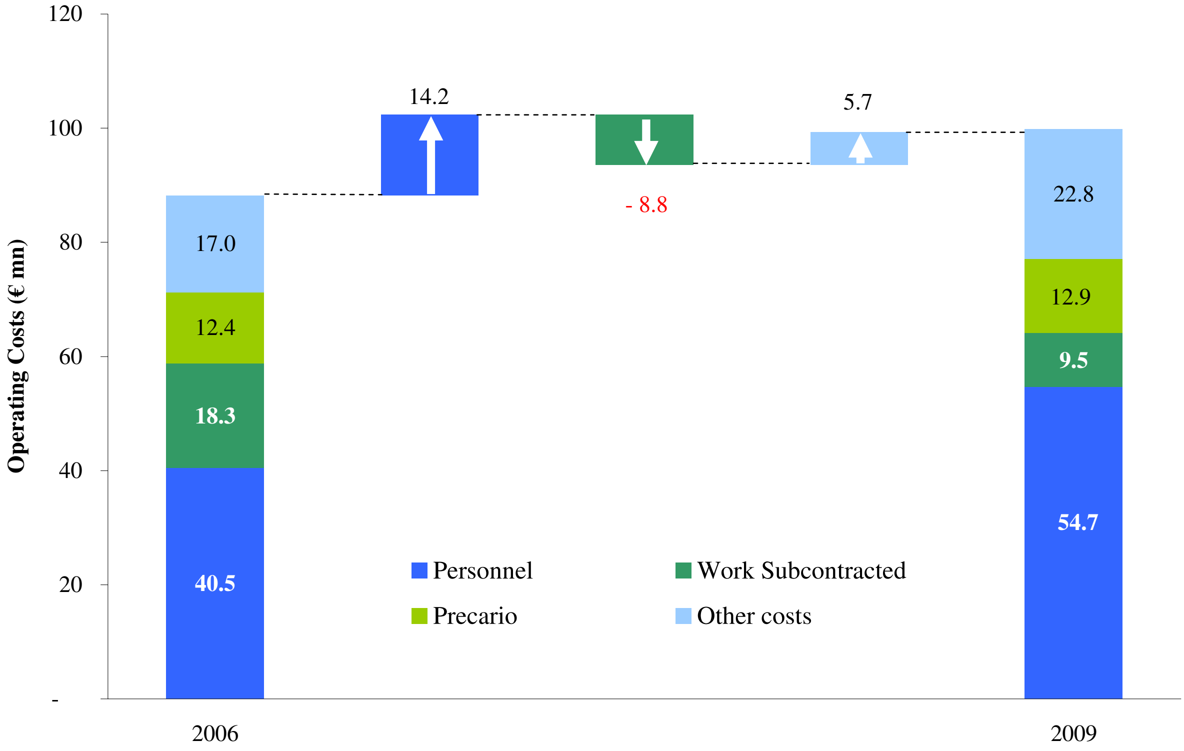
4.1 Gas

Stedin reports costs for the gas network in a slightly different way than Liander. Personnel and subcontracting costs again contribute the majority of operating costs, but Stedin places significantly more costs in the "other" category than Liander. If personnel and subcontracting account for roughly 65% of total gas network operating costs for Stedin, the "other" line item contributes a further 20% or so. In contrast, the other line item contributed only 1-2% of total costs for Liander. Presumably Stedin shifts to the "other" cost category many cost components which Liander places

[14] The annual report attributes a further €23 million of the roughly €100 rise in operating costs for the gas and electricity networks to a special staff bonus payable upon unbundling, and €8 million to increased maintenance on the electricity transport grid. Liander did not mention either of these items in our discussions.

in the personnel and subcontracting lines. Precario is again the only other sizeable expense, accounting for roughly 10-15% of operating costs between 2006 and 2009. Like Liander, Stedin stressed that it had no control over precario and that in future it expected municipality budget deficits to motivate hikes in precario. Figure 8 illustrates the change in Stedin's gas network operating costs from 2006 to 2009, and highlights the important shifts in the underlying cost components.

Figure 8: Gas network cost development (2006-2009)

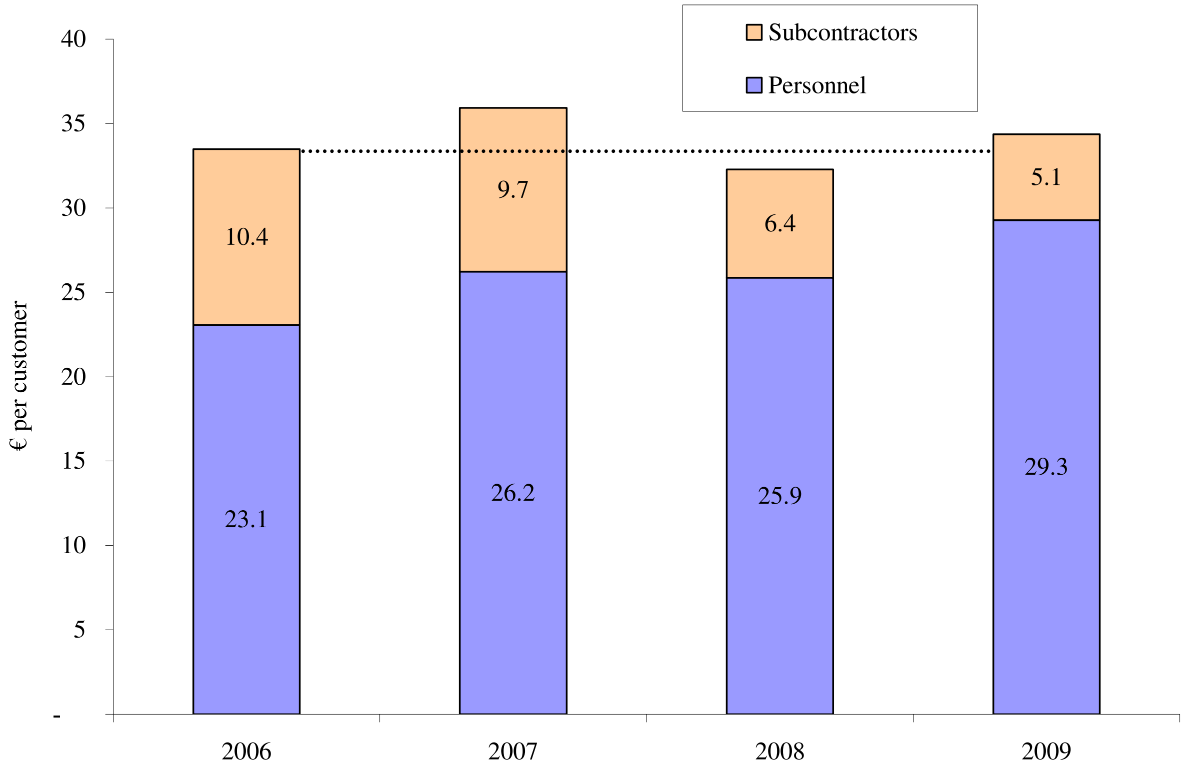


In absolute terms, Stedin's gas operating costs (excluding connections) have increased by more than 10% over three years, or roughly 4% year-on-year. Personnel costs associated with the gas network rose substantially over the period. The rise occurred in two stages: by €6 million or 15% in 2007, before a further rise of €8 million or 15% in 2009. The general rise in Dutch wages of 5% accounts for only a fraction of this increase.[15] But as personnel costs rose, subcontracting costs roughly halved, from €18 million in 2006 to just over €9 million in 2009. Like Liander, rising personnel and falling subcontracting expenses is consistent with the transfer of numerous corporate services in house. In effect, the total of personnel and subcontracting costs for Stedin's gas network saw only a modest rise of 3% year-on-year over the period and a slight decrease in real per customer terms. Stedin clarified that almost all of the subcontracting expenses (*kosten uitbesteed werk*) related to purchases from third-party contractors, and only a small amount were for services corporate services bought in from Eneco.

[15] Personnel costs associated with Stedin's gas network rose by a total of €15 million between 2006 and 2009, close to the absolute increase observed by Liander.

Also like Liander, Stedin explained that unbundling and the change in the market model prompted substantial corporate re-organisation, with functions such as legal, treasury and other financial services, communications, billing and IT coming in-house. Previously the gas network had sub-contracted these services from other corporate entities, and the relevant share of corporate expenses had appeared in the subcontracting cost line. As an illustration, Stedin explained that employee numbers at its two network companies had risen within a short space of time from roughly 500 prior to restructuring to over 1,000. Even so, Stedin allowed that the effect of the re-organisation was perhaps less dramatic for it than for some other DNOs, in part because Stedin did not consider itself as "thin".

Figure 9: Personnel and subcontracting



"Other" operating costs contributed the rest of the overall rise in Stedin's gas network operating costs, with an absolute rise of close to €6 million. This was equivalent to a rise of €3 per customer or 25% year-on-year for the "other" line item. Notes to the CODATA sheets indicate that the "other" line item for Stedin covers principally a management fee, costs associated with the billing system and "other indirect costs". However, the notes do not relate to the regulated gas network alone. They relate to the combination of the regulated network business plus the unregulated gas connections business. They therefore cannot indicate exactly what drove the changes in "other" costs for the regulated business. Yet the notes remain illuminating and provide some insight into any trends underlying the change in "other costs", given that the gas network business contributes much more to overall operating costs than the connections business.

Several movements underlie the changes in "other" costs. Management fees declined by roughly €2 million between 2006 and 2009. The management fees represent general fees paid to the parent holding company to cover the costs relating to services provided by the holding company to

Stedin. These services include Risk Management, Legal, Treasury, Management Board (*Raad van Bestuur*), Strategy, etc..[16] Stedin claims that the management fees will disappear altogether when unbundling is complete, but that decrease will be offset by an increase in Stedin's OPEX as the services are brought in house. Billing system costs moved around somewhat but registered a net gain. They started at €3.5 million in 2006, then rose to €9 million in 2008, before dropping back to €7 million in 2008, for a net gain of just over €3 million over the period. Management fees and billing system costs could therefore have contributed at most €1 million or a sixth of the rise in "other" costs.

The remaining €4 million rise in "other costs" stemmed from the "indirect costs" cost category. The rise in indirect costs was in fact much more than €4 million, reflecting the combination of the regulated network business and connections. Roughly a third of the increase in "indirect costs" related to spillover from investment programs. IFRS accounting standards require that the indirect costs associated with producing capital assets are expensed in the year an asset is activated. But more was going on than just spillover from investment activity. The notes leave unexplained the remaining two-thirds of the increase in indirect costs.[17] Given the re-allocation of staff to the network it might appear reasonable to expect an associated increase in the gas network's allocation of general overhead for buildings and other facilities etc.[18] Unlike Liander, Stedin claimed that cost allocation keys had remained constant over time. It said that the relevant keys were network revenues or costs.

4.2 **Electricity**

Stedin breaks out operating costs for the electricity network into four principal cost components in addition to the general category of "other": transportation charges paid to TenneT, the cost of energy purchases needed to cover losses, direct personnel expenses and subcontracting. Transportation charges accounted for roughly 15-20% of operating costs throughout 2006 to 2009; energy purchases between 20-25%; and the combination of personnel and subcontracting roughly 40%. "Other" costs account for the remaining 15-20%. Like for gas, Stedin appears to allocate some costs to the "other" line item which Liander places in personnel or subcontracting. Precario accounted for about 4% of operating costs between 2006 and 2009. Figure 10 illustrates the change in operating costs from 2006 to 2009, and highlights the important shifts in the underlying cost components.

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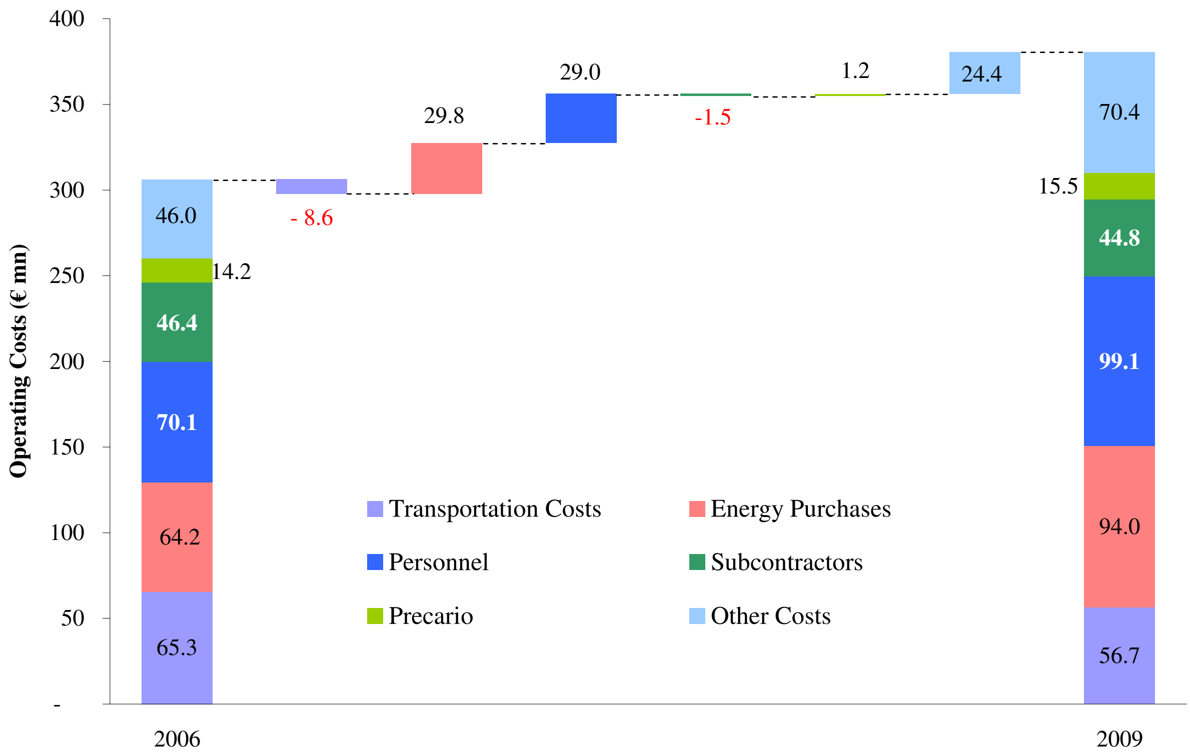
[16] As such, the management fee is not necessarily connected to unbundling.

[17] The total rise in the line item titled "indirect costs" is larger than the rise in the entire "other costs" reported for the gas network. The difference in magnitudes reflects in part the bundling of "indirect costs" and the regulated gas network and the connections business.

[18] Interestingly, exactly the same patterns underlie the comparable rise in "other" operating expenses for Stedin's electricity network.

Figure 10: Electricity network operating costs



Stedin's payments to TenneT declined steadily by about 20% in absolute terms between 2006 to 2009, equivalent to a €5 decline in per customer costs in three years. Stedin explained that the decrease was partly down to network re-configuration, whereby it optimised the number of connections between its own grid and TenneT. Reducing the number of connection points enabled Stedin to aggregate load across its network and so minimise the capacity needed on the TenneT grid. Stedin did not indicate what proportion of the decline was accounted for by network reconfiguration.

The declining trend resulted in a reduction of Stedin's contribution to TenneT's overall revenue requirement over time. In 2006 and 2007, Stedin contributed as much as 18% of TenneT's overall revenue requirement: Stedin's transport costs of €65 million out of a total revenue requirement of roughly €360 million. Stedin's share declined to 16% in 2008 and to as little as 11% in 2009. In 2009, Stedin's percentage contribution drops by about a third, reflecting that the reduction in Stedin's transportation costs coincided with an increase in TenneT's revenue requirement. Stedin believed that the 2009 number probably was artificially low because TenneT had not fully anticipated the effects of the recession and overestimated consumption when calculating the tariffs. As a result Stedin believes that TenneT's 2009 tariffs were lower than they should have been, and that TenneT collected less money than it was allowed. Stedin expects TenneT to raise tariffs in 2010 to cover any 2009 shortfall, and observes that any rise in tariffs would flow through into an increase in Stedin's transport costs relative to 2009.[19] Stedin has not yet sold a substantial part of its HV grid to TenneT because much of the network is subject to cross-border lease agreements.

The cost of Stedin's energy purchases rose from €64 million in 2005 to €94 million in 2009. Stedin explained that they categorise losses in terms of purely technical and administrative. Technical losses relate to power loss inherent in the transmission of energy across the network. Administrative losses relate to power that cannot be billed to a customer, either because there is no customer registered at the address where power was used or because of billing system errors. Stedin estimated that administrative losses accounted for €14 million in 2008 or roughly 20% of overall energy purchase costs. Table 2 illustrates how administrative costs varied between 2006 and 2008. Stedin also thought that recent investments in its billing system had helped control administrative losses and it expected administrative losses to decrease slightly in future, perhaps reducing by as much as a couple of million euros over the next few years. While Stedin was confident in its ability to control administrative losses, it did not appear to believe that it could really affect the volume of technical losses.

Table 2: Stedin, cost of technical and administrative losses 2006 to 2009 inclusive, € million

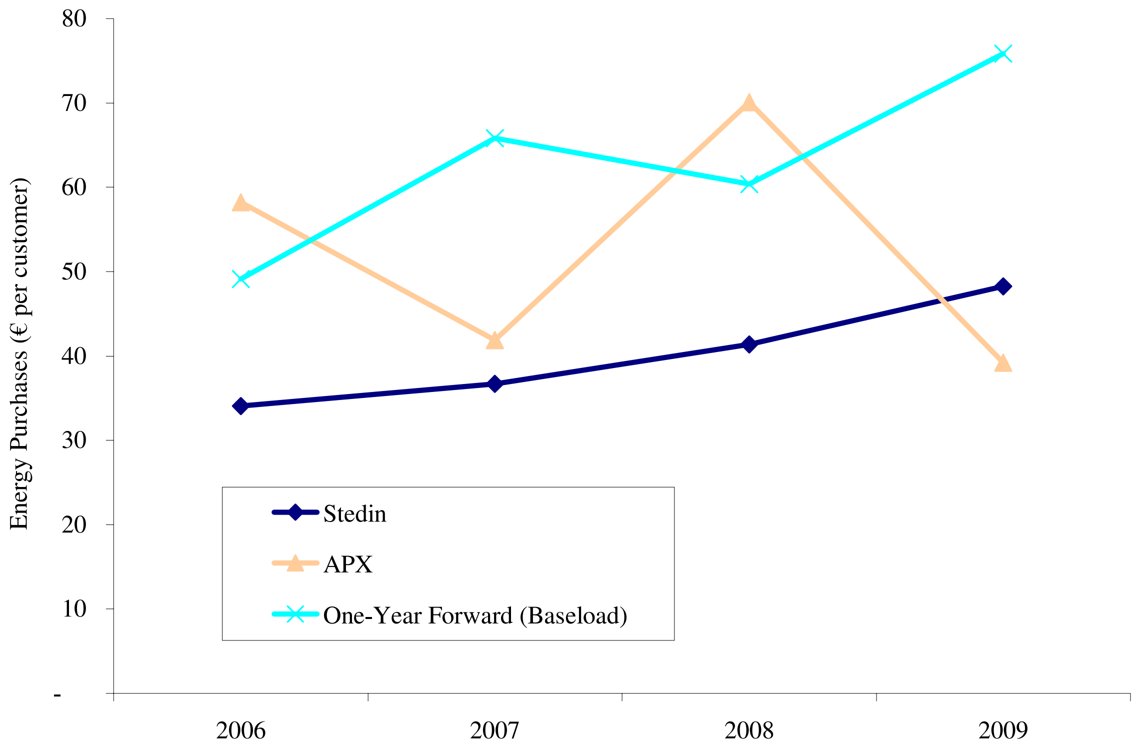
	2006	2007	2008	2009	Average '06-'09
Adminstrative	23.0	15.8	14.0	27.0	20.0
Technical	41.2	57.0	66.6	67.0	58.0
Total	64.2	72.8	80.6	94.0	77.9
Admin losses, % of total	36%	22%	17%	29%	

Source: Stedin

In common with other DNOs, Stedin buys the vast majority of the power needed to cover losses under long term contracts, and only a fraction on the APX. Over the period in question, Stedin had long-term contracts in place with Eneco. Stedin could not recall the precise details of these purchase contracts, but thought that prices could be based on some sort of lagged index, where the price at any point in time reflected the average of APX prices in the previous six or twelve months. Figure 11 compares Stedin's energy purchase costs per customer, with average annual APX prices and average annual price for a one-year forward contract. As for Liander, we plot average forward contract prices at the date of delivery when the contract ultimately would be settled, rather than the date when the contract would originally have been written. The upward trend in Stedin's energy purchase costs seems more closely related to the trend in forward contract prices than anything to do with the APX.

[19] We note that any subsequent rise in TenneT's general tariff level would simultaneously affect all of the DNOs. In other words, the sharp rise in Liander's transportation costs in 2009 could have been even worse, but for TenneT's apparent failure to anticipate the impact of the recession on electricity demand.

Figure 11: Energy purchase costs



Stedin indicated some concern that it had paid more for power than they might have done using another procurement strategy. Stedin mentioned that an internal proposal has been made to buy more power on the APX in future. If we assume the volume of losses remained constant between 2006 and 2009, Stedin's energy purchase costs rose by roughly 25% more than if it had merely bought power on the APX.[20] At the same time, Stedin's energy purchase costs rose by about 5% less than they would have had it always purchased power one-year forward.[21]

Stedin's electricity network saw a comparable rise in personnel costs to its gas network. Between 2006 and 2009, personnel costs for the electricity network rose by 41%, while gas network personnel costs rose by 48%. However, unlike for the gas network, subcontracting costs for the electricity network stayed flat in absolute terms. As a result, the combination of personnel

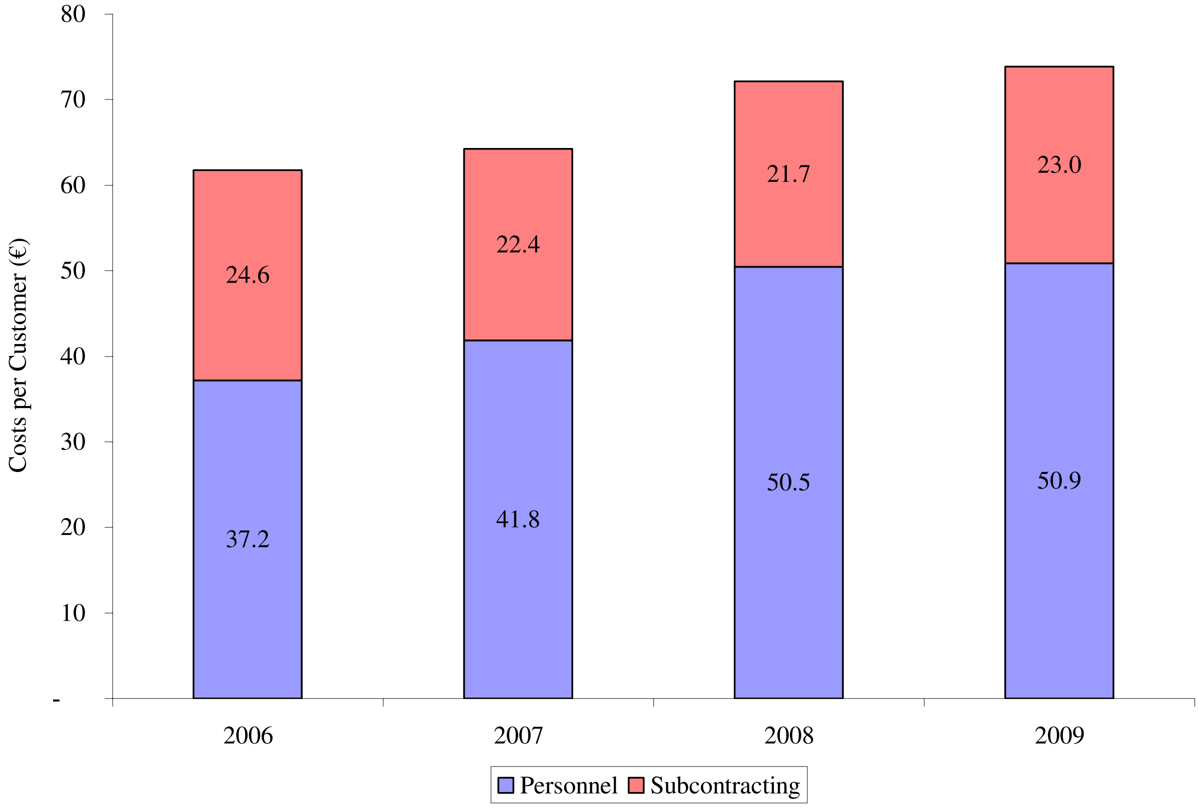
[20] This is not quite the same as saying that Stedin overpaid relative to the APX, more that Stedin did worse with respect to APX prices over time. Even if it did worse over time, it remains logically possible that Stedin may have beaten a "100% from APX" purchase strategy.

[21] This is again not quite the same as saying that Stedin underpaid relative to one-year futures, just that Stedin did slightly better with respect to a "100% one-year forwards" purchasing strategy over time. For illustration, we calculate the present value of Liander's actual energy purchase costs as of January 2006 - €394 million. We apply a discount rate of 6% to the numbers reported in the CODATA sheets. The discount rate reflects in part the risk associated with power prices. Starting at 2006, we then estimate what Liander's energy purchase costs would have been if the only changes over time related to price movements on the APX. The calculations indicate that Liander paid just over €85 million more in present value terms than suggested by price movements on the APX. We perform a similar analysis using one-year baseload forwards instead of APX prices.

and subcontracting for the electricity network rose by €27.5 million in absolute terms, equivalent to adding €12 per customer or 14% in real per customer terms over three years.

The 14% rise in real per customer terms over three years compares to a slight decline in real per customer personnel and subcontracting costs for the gas network, but comes in at half of the rise observed for the combination of the personnel and subcontracting at Liander's electricity network.[22] This pattern of costs is consistent with the transfer of corporate personnel, such as IT and administrative functions such as data-cleaning, maintenance etc. in-house. In common with other DNOs, Stedin noted that they undertook substantial investments in IT systems, in part motivated by unbundling and the introduction of the market model. It believed that some of the rise in personnel and subcontracting stemmed from these investments. Stedin estimates that from 2006 to 2009 there was a rise in ICT OPEX expenses due to the market model transition of €15 million. Over the same period the rise in OPEX due to increases in other investments (indirect costs) was roughly €9 million.

Figure 12: Personnel and subcontracting



"Other" costs registered a further €26 million increase between 2006 and 2009, equivalent to a rise from €24 to €36 per customer. The notes to the CODATA sheets indicate that a bit under half

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[22] Of course, Stedin reports more costs in the "other" line item than Liander. If we ensure consistency by comparing the totals for personnel, subcontracting and other costs, we find that both Liander and Stedin began with costs of around €86-87 per customer in 2006, but both then saw increases, to €110 per customer for Stedin and €119 for Liander. The extra costs of €9-10 per customer for Liander may relate to its "upgrade investments" discussed earlier in this report. For its part and as we explain below, Enexis achieved a reduction in personnel, subcontracting and other through the period.

of the rise related to a step change in billing system costs in 2009, presumably associated with corporate re-structuring and the need for separate systems for the network and supply companies. The notes also indicate that the other half of the rise related to an increase in "indirect" costs. Although the notes do not provide much more detail, the one thing we can say is that none of the rise in indirect costs was "asset related".[23]

Stedin suggested several other factors placed upward pressure on operating costs, without indicating exactly which operating cost components would be affected. One factor was the increasing rate of new connections. In our meeting, Stedin observed that it experienced a remarkable increase in requests for new connections since 2006. This is confirmed by other of the CODATA sheets, which show Stedin's new electricity connections rising from about 75,000 in 2007 to over 220,000 in 2009. In contrast Liander's rate of new connections remained constant at between 40-45,000 per year over the same period.

Stedin claimed that much of the activity in new connections reflected a boom in distributed generation across its network – mainly agricultural CHP and wind power, but also Photovoltaic (PV or solar) power. In 2007/08 generating electricity with gas was extremely profitable. So much so that farmers could earn more money generating power than selling fruit and vegetables. Stedin even claimed that during the relevant period one bank actively encouraged farmers to invest in generation plant and made financing contingent on their doing so. Stedin also explained that requests for new connections have dried up somewhat more recently following the decline in APX prices. Stedin expects new connections to return to historic levels in 2010. Stedin thought that the boom in new connections activity would have prompted additional operating costs, in part because it is sometimes difficult to fully allocate the costs of personnel and other items needed to manage capital projects to the capital account. Although claiming it was important, Stedin did not know precisely how significant this effect had been.

In our view, this explanation faces several problems. The notes to the CODATA sheets register no increase in asset related "indirect costs", which might be a natural destination for any spillover from connection activity into operating costs. To put this observation another way, if the associated operating costs don't appear in asset related indirect costs, then precisely where would they go? Moreover, while investment increased strongly from €75 million in 2006 to €135 million in 2008 consistent with Stedin's new connections narrative, investment then fell back to €117 million in 2009, despite new connection activity really taking off. The profile of capital expenditures over time does not appear to match what we would expect if new connections were so important. Finally, a general comment on timing. Although we see an increasing number of new connections each year through the period, we see a big increase in connections in 2009 precisely at the moment power prices dropped and credit conditions tightened. For Stedin's explanation to make sense, we have to believe that the spike in 2009 connection activity relates to investment decisions taken in 2008 when CHP still looked attractive.

[23] The notes break out "indirect costs" into asset related and non-asset related. "Asset related" appears to reflect the indirect costs of producing capital assets. IFRS accounting standards require that the indirect costs associated with producing capital assets are expensed in the year an asset is activated. Asset-related indirect costs rose only slightly during the period, non-asset related indirect costs grew by close to €19 million.

Another factor mentioned by Stedin was its Cross-Border Leases. In common with other DNOs, a substantial part of Stedin's HV grid was sold to foreign investors under sale and lease-back agreements. Stedin explained that many of these contracts obligate Stedin to buy back the network for a pre-determined price at some point in future.[24]

Stedin claimed that these lease obligations created additional expenses during the period and that these expenses were booked under operating costs. For example, Stedin said that it had to post an additional collateral under the lease contracts in 2008/9, confirming to counterparties its continued ability to satisfy any outstanding contractual obligations such as the repurchase of the network at the contractually-determined price and time. Stedin said that posting the extra collateral cost it about €15 million and it considered this cost as a financing expense. It believed the increase in collateral requirements was triggered by the broad change in global credit conditions associated with the credit crisis. It explained that the details of the lease contracts are highly complex and only understood by a few specialists within the company. It is not wholly clear where the €16 million of extra collateral costs may have appeared in the CODATA sheets, but one possibility is that they accounted for the majority of the rise in "indirect costs" over time.

Finally, we note that 'precario' remained relatively constant for Stedin's electricity network at about €27-28 million per year during 2006-2009, except for 2007 when precario dropped to €22 million. Stedin explained that the drop related to success in a refund claim made for a year prior to 2006.

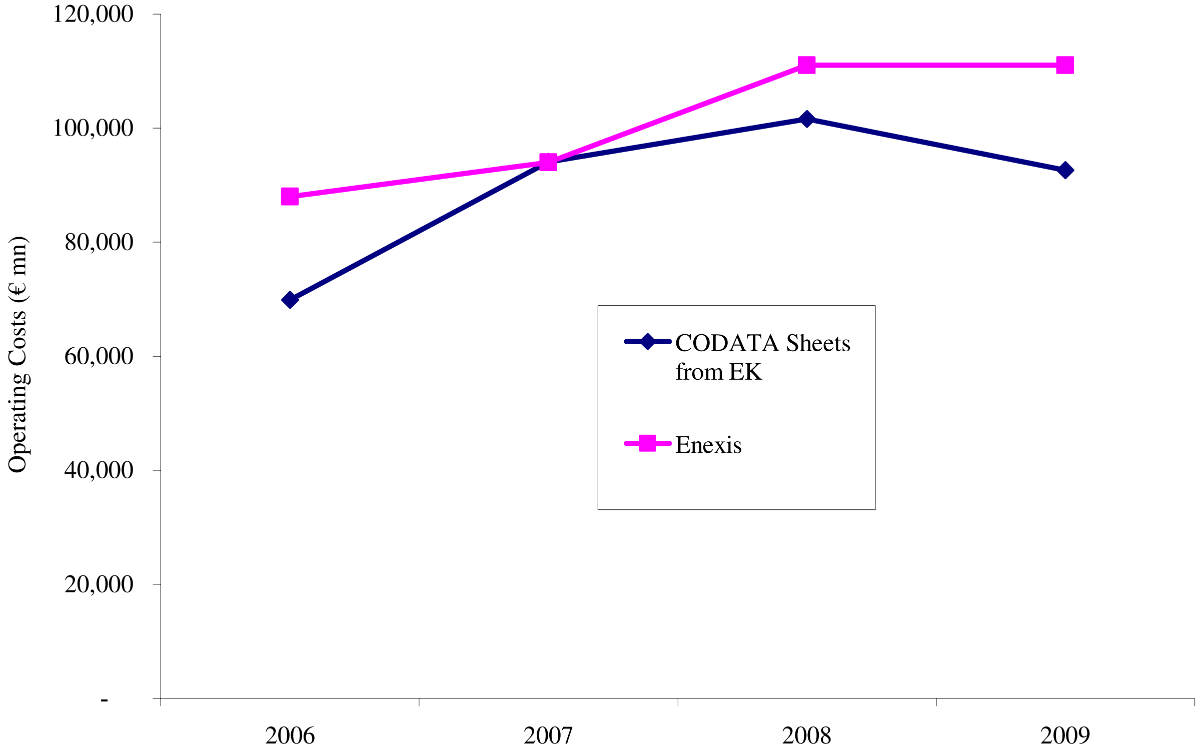
5 Enexis

5.1 Gas

Enexis does not break out operating costs to the same level of detail as the other DNOs. The "other" category represents almost all of the operating costs for the Enexis gas network, and unfortunately Enexis provides no detail concerning what types of costs "other" includes. In our meeting, Enexis explained that part of the difficulty related to the complexity of the underlying cost allocations. Over the period in question, Enexis used over 30 different keys to allocate costs between the electricity and gas networks and between the networks and other corporate entities. In any event, Enexis disputed the level of operating costs we find reported in the CODATA sheets. Figure 13 compares the values found in the CODATA sheets, provided to us by the EnergieKamer and what Enexis considers the true cost level.

[24] We observe that the annual leasing charges associated with these contracts will appear in Stedin's operating costs, and cover both the operating and capital charges associated with the underlying assets.

Figure 13: Gas operating costs



In 2009, the difference between the lines relates to the amortization of a one-off million payment for municipality subcontracting. Enexis paid €130 million sometime toward the beginning of 2008 to municipalities. The payment settled all outstanding liabilities to the municipalities and was reflected by an annual non-cash charge of €18.9 million to income (amortized over 10 years at a bit over 7%). The CODATA sheets supplied by the EnergieKamer subtract the €18.9 million amortization charge from the reported level of other costs in 2009. The 2008 CODATA sheets subtract €9.45 million from the 2008 total of other costs, presumably reflecting that the one-off payment was made roughly halfway through 2008. We are unclear what lies behind the €18 million difference in 2006.

In any event, if we ignore the amortization charge associated with municipality subcontracting and also the 2006 result because of uncertainty surrounding the true cost level, we immediately observe that Enexis's gas network costs increased roughly €6-7 million in 2008 before returning back to or slightly below the 2007 level in 2009. The 2008 peak represented a cost increase of roughly €4 per customer or 7% relative to 2007. Notes to the CODATA sheets indicate that €2 million or a third of the increase related to a provision associated with the anticipated introduction of the market model. Enexis recorded a comparable €5.3 million provision for the electricity network in 2008, indicating a combined provision of €7.3 million for adoption of the market model. The relative magnitude of the provisions for the gas and electricity networks broadly confirm what Enexis told us about cost allocation. It indicated that normal practice was to allocate roughly 30% of common costs to gas and 70% to electricity. Enexis explained that the €2 million provision specifically related to IT system-related costs required to accommodate the market model.

A further €0.5 million of the increase in costs related to re-branding, which was prompted by network unbundling. The remaining €3-4 million of 2008 cost increases concerns additional provisions taken by Enexis. In total, Enexis took additional provisions of €8 million on top of the €2 million relating to the market model. Almost €2 of the €8 million was a provision for bad debts. Notes to the CODATA sheets indicate that Enexis took similar provisions in previous years, but that it lumped the amounts together with everything else in "other" costs. A further €3 of the €8 million provision relates to remediation costs and employment anniversary benefits. We are not sure if Enexis incurred similar provisions in previous years. The remaining €3 million relates to additional personnel costs, which Enexis indicated were related to corporate restructuring and prompted by unbundling. The additional personnel costs related to bringing general corporate functions such as treasury, communications etc. in-house and doubling them up across networks. In other words, Enexis took total provisions of at least €5 million in anticipation of the adoption of the market model and unbundling[25], and spent a further €0.5 million on re-branding. This level of additional cost explains almost the entirety of the overall increase in operating costs in 2008.

In 2009, Enexis gas network operating costs declined by €9 million relative to 2008, more or less returning back to the 2007 level. Costs fell relative to 2008 even though Enexis continued to take provisions related to the adoption of the market model and unbundling. 2009 provisions totalled roughly €7 million, compared with total 2008 provisions of just over €10 million. Just over half of the 2009 provisions - €3.6 million - explicitly relate to unbundling and adoption of the market model, compared with at least €5 million in the 2008 provisions, implying a reduction in the level of unbundling and market model related provisions of €1.5-2 million relative to 2008.

Enexis attributed any additional decline in 2009 costs to efficiency improvements, but could not specify where it achieved these efficiencies. In general, Enexis was pleased that it had been able to hold gas network operating costs more or less flat despite the need to incur roughly €10 million of provisions relating to the market model and restructuring. Aside from shifting expenses between line items it believed that restructuring should have left personnel costs largely unaffected, in part because Enexis never became as "thin" as other networks. Enexis thought there might even have been some limited cost savings. Not all corporate personnel made the transition to the unbundled networks and as a result Enexis thought that the unbundled networks began with an efficient level of staffing. Enexis even believed that re-structuring could prompt some efficiencies going forward, given the investment in enhanced systems.

In total, 2008 and 2009 gas network operating costs contained roughly €10 million of extra costs, €3.5 million of which related to the market model and €6.5 million of which related to restructuring. However, most of the actual spending did not occur until 2010, and Enexis indicated that the €10 million of provisions were a long way short of covering actual costs. Without further work, Enexis did not know what the precise level of actual costs was or how far short the provisions came.

Finally, we note that according to the CODATA sheets, costs rose by close to €24 million between 2006 and 2007, equivalent to a rise of €13 per customer or by 33% relative to 2006. Enexis disputed the 2006 number and claimed that the CODATA sheets understated 2006 costs by

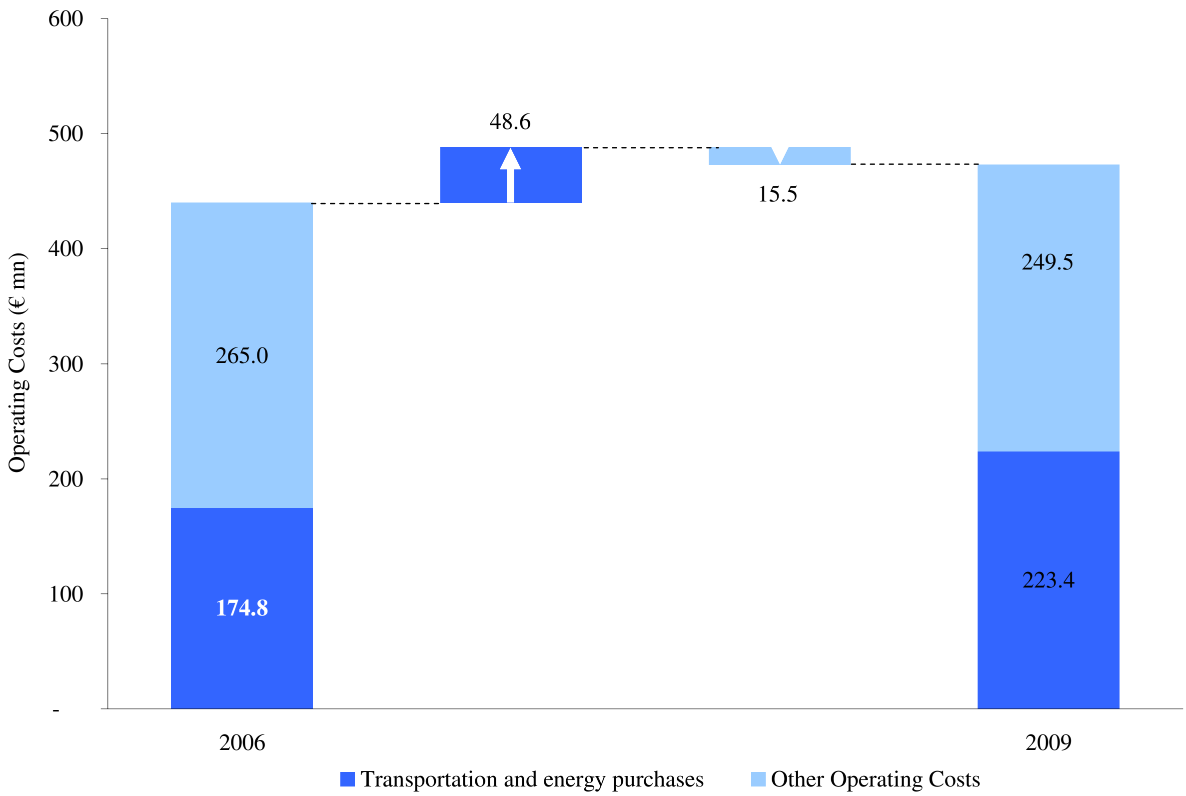
[25] €2 million for the market model plus €3 for unbundling.

as much as €18 million. Whatever the true cost level, Enexis indicated that it altered cost allocation approach sometime during 2006 and 2007, and the change in allocation approach shifted €7-8 million to the gas network from electricity.

5.2 Electricity

Enexis breaks out operating costs for the electricity network slightly more than for the gas network, but still less than the other DNOs. We have essentially two categories over the four years from 2006 to 2009: transportation and energy purchase costs, and other. Transportation and energy purchase costs contribute between 40-50% of the costs; other the remainder. Figure 14 illustrates the change in operating costs from 2006 to 2009, and highlights the important shifts in the underlying cost components. Unlike for gas, Enexis did not dispute the cost level.

Figure 14: Electricity network operating costs[26]



Of the three DNOs investigated, Enexis experienced the smallest rise in total operating costs between 2006 and 2009. Operating costs increased by €33 million over the three year period, or only 2.3% year-on-year – little more than inflation. Operating costs for the electricity networks of both Liander and Stedin rose substantially in real terms. However, Enexis saw an increase in the combination of transportation and energy purchase costs comparable to the other two networks.

[26] For Enexis, we cannot separate between precario and other costs as precario is reported separately only from 2007 onwards. In 2006 it is included in other operating costs. However , precario does not seem to be a significant component of operating costs. In 2009 it amounts to €1.7 million.

Where Enexis appears to have kept costs down is the other category, which broadly compares to the personnel and subcontracting line items for the other two networks.

Enexis saw an increase in transportation and energy purchase costs of €20 million in 2007, €10 million in 2008 and a further €20 million in 2009. We do not know whether it was transportation charges or energy purchase costs which prompted the increase in costs in 2007 and 2008. What we do know is that there was a step rise in transportation costs between 2008 and 2009: from €66 million in 2008 to over €100 million in 2009. The €40 million hike in transportation costs was offset somewhat by a €20 million decline in energy purchase costs. Enexis attributed both the rise in transportation costs and at least part of the decline in energy purchase costs to the sale of high-voltage grids to TenneT. Of the three DNOs, Enexis said it had the 'cleanest' transfer of high voltage assets to TenneT because of the relative absence of associated cross-border leases.

While the sale of high voltage assets probably had some upward impact, it appears difficult to explain the entire rise in transportation costs with reference to the sale of high voltage assets alone. According to the 2008 CODATA sheets, Enexis sold high voltage assets to TenneT with total book value of roughly €40 million. Depreciation of these assets occurs over 25 to 50 years, implying a depreciation charge of roughly 1.5-2 million per year. A 10% pre-tax return on the €40 million of assets transferred comes out at €4 million per year. Assuming that TenneT purchased the assets for something close to book value, €1.5-2 million of annual depreciation plus a pre-tax return of €4 million combine to give total capital charges for the transferred high voltage assets of somewhere around €6 million per year. Of course, TenneT's tarrifs would have to cover both the capital and operating costs associated with the transferred high voltage assets, with operating costs including such items as personnel and the cost of energy purchases to cover losses. Yet for the transfer of the high voltage assets to account for the entire €40 million rise in Enexis's transportation costs, we would have to attribute close to €35 million of operating costs each year to high voltage assets with a total book value of only €40 million. This seems unlikely.

Enexis attributed the €20 million decline in energy purchase costs to the sale of the high-voltage grid and recent declines in energy prices. Without further work, it could not allocate the €20 million rise between these effects. Like the other DNOs, Enexis said it covers the majority of losses with power purchased under long-term contracts from its supply affiliate - Essent. Overall, it appears reasonable to assume that the transfer of high-voltage grid to TenneT accounts for perhaps half of the observed rise in transportation costs in 2009 and some undisclosed portion of the decline in energy purchase costs. At least some of the rise in transportation costs remains unexplained, while general price developments doubtless contributed to the decline in energy purchase costs.

Enexis managed to offset the increases in transportation and energy purchase costs with €15 million of savings in other costs, equivalent to savings in other costs of over 4% year-on-year in real terms. €6 million of the savings relates to the re-allocation of costs from electricity to the gas network. But the level of savings appears even more impressive, given that Enexis also incurred €25 million in provisions and other costs in 2008 and 2009 relating to unbundling and the adoption of the market model.

€13 million of provisions came in 2008. Enexis anticipated over €5 million in costs for the market model, and a further €7-8 million for restructuring and additional personnel costs. The market model costs reflected the operating costs associated with implementing new IT infrastructure and systems. As well as the provisions, Enexis allocated €1.5 million of re-branding costs to the electricity network in 2008. Then in 2009, Enexis took further provisions of €10-11 million, €6 million of which related to unbundling and €4-5 million of which related to the market model. In total, Enexis took provisions of close to €10 million for the market model, €14 million for unbundling, with a further €1.5 million of expenses for re-branding.

As for the gas network, Enexis indicated that it actually spent much of the money related to the change in market model and unbundling in 2010 and that the actual costs exceeded the value of the provisions. Unbundling and market model costs of more than €25 million for the electricity network and a further €10 million for the gas network appear broadly in line with the level of personnel and subcontracting cost increases observed at Stedin, but substantially less than the increase observed at Liander in 2009. Also like for the gas network, Enexis attributed any additional decline in 2009 costs to general efficiency improvements. Enexis was pleased to have achieved real terms declines in "other" operating costs of the electricity network despite taking roughly €25 million of extra provisions relating to the market model and restructuring. Without the provisions, Enexis would have reduced electricity network operating costs by as much as 7% in real terms year-on-year between 2006 and 2009.

Interestingly, in common with Stedin, Enexis experienced a large growth in the number of new connections, and for the same reason – the boom in argricultural CHP prompted by soaring spark spreads and low interest rates. Between 2007 and 2009, Enexis saw an increase in new connections per year of nearly 200%. Also in common with Stedin, Enexis reported increasing capital expenditure needs, associated with the replacement of vintage assets and the need to accommodate distributed generation. However, in contrast to Stedin, Enexis believed that new connections and heavy investment activity had a minimal effect on operating costs. Enexis explained that its accounting policy requires the full capitalisation of all costs associated with new connections and investments. As a result, it did not expect there to be any significant indirect personnel or other costs associated with the production of the assets. This is in contrast to both Liander and Stedin – who claimed that investment activity often spilled over into operating costs.

Appendix I : Details of operating costs

Table 3: Gas network – Liander

	2006	2007	2008	2009	Change Over Data Period	Annual Growth Rate
Customers						
<170,000m3	2,088,925	2,104,913	2,122,238	2,128,608	1.90%	0.63%
>170,000m3	2,629	2,455	2,364	2,398	-8.80%	-3.02%
Total	2,091,555	2,107,368	2,124,602	2,131,006	1.89%	0.62%
Opex						
Personnel	6,435	8,956	24,699	21,975	241.51%	50.59%
Subcontracting	81,636	77,891	79,957	68,287	-16.35%	-5.78%
Precario	6,290	7,677	7,596	7,005	11.36%	3.65%
Other	1,937	1,877	(123)	1,746	-9.85%	-3.40%
Total	96,297	96,401	112,129	99,013	2.82%	0.93%
Per Customer						
Personnel	3.08	4.25	11.64	10.32	235.14%	49.65%
Subcontracting	39.03	36.96	37.63	32.04	-17.90%	-6.36%
Precario	3.01	3.64	3.58	3.29	9.29%	3.01%
Other	0.93	0.89	(0.06)	0.82	-11.52%	-4.00%
Total	46.04	45.75	52.79	46.47	0.93%	0.31%
Personnel + Subcontractors	42.11	41.22	49.27	42.37	0.61%	0.20%

Table 4: Electricity network – Liander

	2005	2006	2007	2008	2009	Change Over Data Period	Annual Growth Rate
Customers							
Low		2,748,620	2,763,328	2,797,118	2,821,905	2.7%	0.9%
Medium		27,236	27,667	27,420	28,225	3.6%	1.2%
High		256	338	333	342	34.0%	10.2%
Total		2,776,111	2,791,333	2,824,871	2,850,472	2.7%	0.9%
Opex							
Transportation costs	44,040	43,166	54,864	57,818	76,409	73.5%	14.8%
Purchased Energy	70,912	98,633	115,901	125,465	117,033	65.0%	13.3%
Personnel	5,772	8,510	11,892	58,067	70,255	1117.1%	86.8%
Subcontracting	226,043	227,554	212,107	185,943	263,679	16.7%	3.9%
Precario	6,247	12,581	14,310	14,406	13,888	122.3%	22.1%
Other	5,901	6,948	6,109	(10,341)	6,192	4.9%	1.2%
Total	358,916	397,392	415,184	431,358	547,457	52.5%	11.1%
Opex Per Customer							
Transportation costs		15.55	19.66	20.47	26.81	72.4%	19.9%
Purchased Energy		35.53	41.52	44.41	41.06	15.6%	4.9%
Personnel		3.07	4.26	20.56	24.65	704.0%	100.3%
Subcontracting		81.97	75.99	65.82	92.50	12.9%	4.1%
Precario		4.53	5.13	5.10	4.87	7.5%	2.4%
Other		2.50	2.19	(3.66)	2.17	-13.2%	-4.6%
Total		143.15	148.74	152.70	192.06	34.2%	10.3%
Personnel + Subcontractors		85.03	80.25	86.38	117.15	37.8%	11.3%

Table 5: Gas network – Stedin

	2006	2007	2008	2009	Change Over Data Period	Annual Growth Rate
Customers						
<170,000m3	1,754,768	1,774,703	1,834,952	1,867,018	6.40%	2.09%
>170,000m3	2,088	2,043	1,943	1,966	-5.84%	-1.99%
Total	1,756,856	1,776,746	1,836,895	1,868,984	6.38%	2.08%
Opex						
Personnel	40,495	46,534	47,466	54,669	35.00%	10.52%
Subcontracting	18,281	17,255	11,765	9,475	-48.17%	-19.67%
Precario	12,427	8,265	12,264	12,940	4.13%	1.36%
Other	17,006	26,163	20,576	22,752	33.79%	10.19%
Total	88,208	98,216	92,072	99,836	13.18%	4.21%
Opex Per Customer						
Personnel	23.08	26.22	25.87	29.28	26.89%	8.26%
Subcontracting	10.41	9.71	6.41	5.07	-51.28%	-21.31%
Precario	7.07	4.65	6.68	6.92	-2.11%	-0.71%
Other	9.68	14.73	11.20	12.17	25.76%	7.94%
Total	50.24	55.31	50.15	53.45	6.39%	2.09%
Personnel + Subcontractors	33.48	35.93	32.27	34.35	2.59%	0.86%

Table 6: Electricity network – Stedin

	2005	2006	2007	2008	2009	Change Over Data Period	Annual Growth Rate
Customers							
Low		1,869,299	1,958,299	1,922,063	1,929,346	3.2%	1.1%
Medium		15,545	25,435	18,784	18,889	21.5%	6.7%
High		178	168	180	190	6.9%	2.3%
Total		1,885,021	1,983,902	1,941,028	1,948,425	3.4%	1.1%
Opex							
Transportation costs	71,491	65,280	64,403	67,492	56,660	-20.7%	-5.6%
Purchased energy	63,327	64,205	72,815	80,260	93,964	48.4%	10.4%
Personnel	68,718	70,087	82,990	97,961	99,084	44.2%	9.6%
Subcontracting	42,647	46,356	44,487	42,089	44,849	5.2%	1.3%
Precario	13,325	14,240	14,324	14,761	15,459	16.0%	3.8%
Other	47,238	46,027	51,722	54,603	70,429	49.1%	10.5%
Total	306,747	306,195	330,741	357,167	380,446	24.0%	5.5%
Opex Per Customer							
Transportation costs		34.63	32.46	34.77	29.08	-16.0%	-5.7%
Purchased energy		34.06	36.70	41.35	48.23	41.6%	12.3%
Personnel		37.18	41.83	50.47	50.85	36.8%	11.0%
Subcontracting		24.59	22.42	21.68	23.02	-6.4%	-2.2%
Precario		7.55	7.22	7.60	7.93	5.0%	1.6%
Other		24.42	26.07	28.13	36.15	48.0%	14.0%
Total		162.44	166.71	184.01	195.26	20.2%	6.3%
Personnel + Subcontractors		61.77	64.26	72.15	73.87	19.6%	6.1%

Table 7: Gas network – Enexis

	2006	2007	2008	2009	Change Over Data Period	Annual Growth Rate
Customers						
<170,000m3	1,809,028	1,837,282	1,847,471	1,861,388	2.9%	1.0%
>170,000m3	3,722	3,811	1,983	2,084	-44.0%	-17.6%
Total	1,812,751	1,841,093	1,849,454	1,863,471	2.8%	0.9%
Opex						
Personnel	-	-	-	-		
Impairment	-	211	-	-		
Precario	-	612	617	611	-0.2%	-0.1%
Provisions	-	-	8,426	6,972	-17.3%	-17.3%
Other	69,909	93,279	92,546	85,004	21.6%	6.7%
Total	69,909	94,102	101,589	92,587	32.4%	9.8%
Opex Per Customer						
Personnel	-	-	-	-		
Impairment	-	0.11	-	-		
Precario	-	0.33	0.33	0.33	-1.4%	-0.7%
Provisions	-	-	4.56	3.74	-17.9%	-17.9%
Other	38.57	50.67	50.04	45.62	18.3%	5.8%
Total	38.57	51.11	54.93	49.69	28.8%	8.8%

Table 8: Electricity network – Enexis

	2006	2007	2008	2009	Change Over Data Period	Annual Growth Rate
Customers						
Low	2,460,810	2,473,933	2,507,459	2,529,850	2.8%	0.9%
Medium	26,065	25,916	26,642	26,918	3.3%	1.1%
High	290	242	6,145	194	-33.1%	-12.6%
Total	2,487,165	2,500,091	2,540,246	2,556,962	2.8%	0.9%
Opex						
Transportation costs	174,761	195,143	66,243	104,061	-40.5%	-15.9%
Purchased energy			139,470	119,329	-14.4%	-14.4%
Personnel						
Subcontracting						
Precario		1,673	1,677	1,738	3.9%	1.9%
Provisions			14,584	20,346	39.5%	39.5%
Other	265,024	249,085	248,262	227,402	-14.2%	-5.0%
Total	439,785	445,901	470,236	472,876	7.5%	2.4%
Opex Per Customer						
Transportation costs	70.27	78.05	26.08	40.70	-42.1%	-16.6%
Purchased energy	-	-	54.90	46.67	-15.0%	-15.0%
Personnel	-	-	-	-		
Subcontracting	-	-	-	-		
Precario	-	0.67	0.66	0.68	1.6%	0.8%
Provisions	-	-	5.74	7.96	38.6%	38.6%
Other	106.56	99.63	97.73	88.93	-16.5%	-5.8%
Total	176.82	178.35	185.11	184.94	4.6%	1.5%