

Cost Benchmarking in Energy Regulation in European Countries

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1 Introduction

WIK-Consult has been asked by the Australian Energy Regulator (AER) to provide assistance with regard to a review of cost benchmarking approaches in European energy sectors. The study is an input for the AER research project “Benchmarking Capex and Opex in Electricity Transmission and Distribution”.

Benchmarking covers two aspects, a general productivity improvement and an individual efficiency catch-up. The first corresponds to a shift of the overall production frontier and is determined by real cost changes of efficient operators. The latter is based on an analysis comparing the performance of individual companies in relation to the production frontier. Hence, individual efficiency scores are determined. In most cases, the determination of the frontier shift is not made transparent by national regulators. More often, information on the catch-up element is provided in quite some detail. Therefore, the report focusses on a review of techniques to determine individual efficiency scores, which is named “efficiency benchmarking” throughout the study. Where possible, information on the frontier shift is added.

The country choice is subject to information availability and has been decided cooperatively between AER and WIK-Consult. With regard to regulation of energy networks, the sector can be sub-divided into the sub-sectors gas and electricity transmission and gas and electricity distribution. Concerning sub-sector coverage, the main focus is on electricity distribution with some additions for gas distribution. For the distribution level, the following countries and sub-sectors are considered in this report

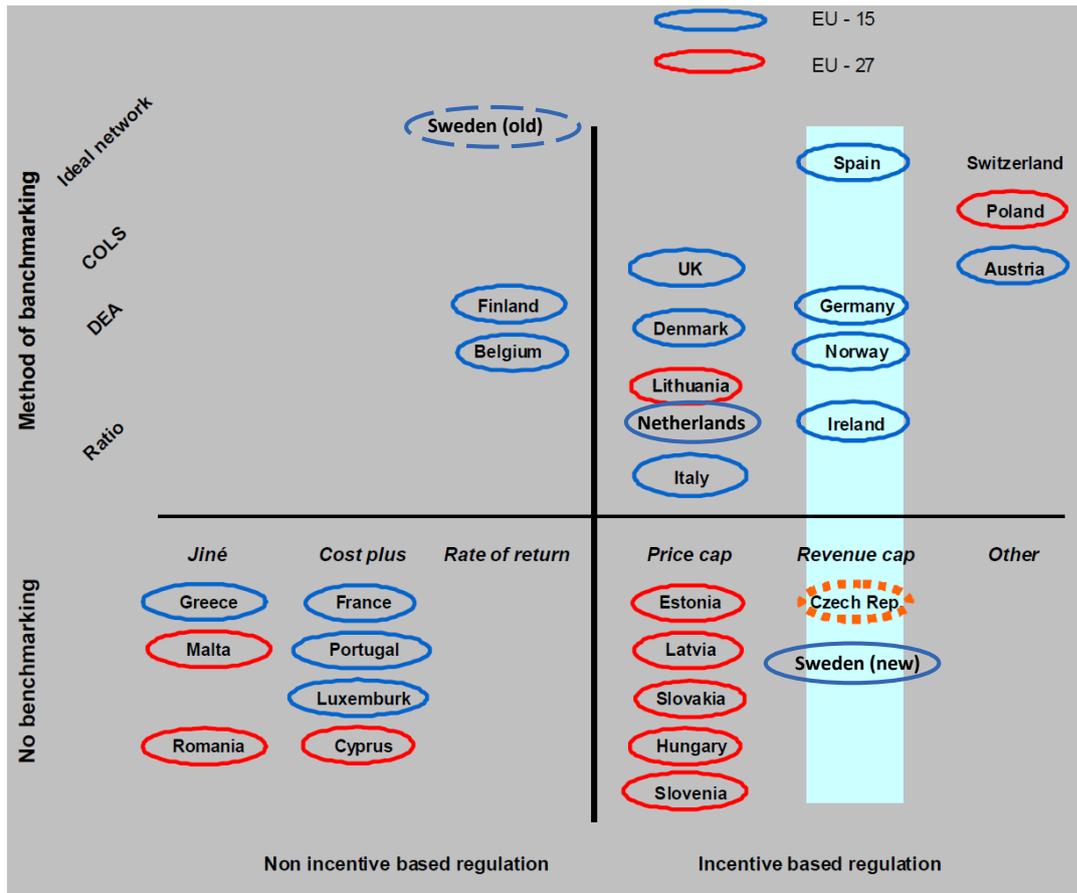
- Austria: electricity and gas distribution,
- Denmark: electricity distribution,
- Finland: electricity distribution,
- Germany: electricity distribution and gas distribution,
- Norway: electricity distribution,
- Spain: electricity distribution, and
- Sweden: electricity distribution.

As shown in Figure 1 and taking into account, that AER has already gathered information for the UK, Ireland and the Netherlands, this provides a fair coverage of European countries having established efficiency benchmarking.

The remainder of the report is structured as follows. Chapter 2 introduces the regulatory framework at the EU level with regard to tariff methodologies and appeal procedures. The main review of the distribution sub-sectors is provided in Chapter 3. Besides the regulatory regimes and efficiency benchmarking approaches, a high-level description of

the industry structure in each country is given. Furthermore, information of national appeal procedures is added. Chapter 4 contains examples of efficiency benchmarking approaches applied to transmission system operators. Finally, we conclude.

Figure 1: Regulatory regimes in European countries



Source: ERO (2009: 12).

Note: Sweden and the The Netherlands have been added by WIK-Consult.¹

¹ Dutch electricity DSOs are regulated by a system of national yardstick competition (with price caps). The yardstick is determined by the sector average cost per output, including an estimate of the growth in total factor productivity (Energiekamer 2011).

2 EU framework

2.1 Tariff methodologies

In 2009 the Council of the European Union formally adopted the new liberalization package for the European gas and electricity markets. It will take legal effect between 2011 and 2013. After the first directives at the end of the 1990s and the acceleration directives in 2003, it is the third energy package and it consists of:

- the directive concerning common rules for the internal market in electricity (Directive 2009/72/EC),
- the directive concerning common rules for the internal market in natural gas (Directive 2009/73/EC),
- the regulation establishing an Agency for the Cooperation of Energy Regulators (Regulation 713/2009),
- the regulation on conditions for access to the network for cross-border exchanges in electricity (Regulation 714/2009),
- the regulation on conditions for access to the natural gas transmission networks (Regulation 715/2009).

The package includes rules for the unbundling of energy supply and production from network operation, aims to ensure fair competition between EU companies and third country companies and wants to strengthen the power of the national regulators. Furthermore, the creation of an European energy agency was envisaged: The Agency for Cooperation of Energy Regulators, ACER, has been launched at the beginning of 2011.

In the following we focus on provisions concerning tariffs and the duties of the regulatory authorities.

The Member States have to ensure the implementation of a system of third party access to the transmission and distribution systems based on published tariffs. In this context, Member States shall ensure that those tariffs, or the methodologies underlying their calculation, are approved prior to their entry into force in accordance with Article 37 Directive 2009/72/EC and Article 41 Directive 2009/73/EC and that those tariffs, and the methodologies, where only methodologies are approved, are published prior to their entry into force.

One of the duties of the regulatory authorities is to fix or to approve, in accordance with transparent criteria, the transmission and distribution tariffs and their methodologies. In this context the regulatory authority has to ensure that network access tariffs collected by the independent system operator include remuneration for the network-owner, which

provides for adequate remuneration of the network assets and of any new investments made therein.

The regulatory authorities shall be responsible for fixing or approving sufficiently in advance of their entry into force at least the methodology used to calculate or establish the terms and conditions for connection and access to national networks, including transmission and distribution tariffs or their methodologies. Those tariffs or methodologies shall allow the necessary investments in the networks to be carried out in a manner allowing those investments to ensure the viability of the networks. In this connection the regulatory authorities shall ensure that transmission and distribution system operators are granted appropriate incentive, over both the short and long term, to increase efficiencies, foster market integration and security of supply and support the related research activities. Regulatory authorities shall have the authority to require transmission and distribution system operators to modify the terms and conditions, including tariffs or methodology.

Any party who is affected and who has a right to complain concerning a decision on methodologies may, at the latest within two months, following publication of the decision or proposal for a decision, submit a complaint for review. Such a complaint shall not have suspense effect.

Thus, the European regulatory framework sets only some general standards with regard to the determination of network tariffs. For transmission network charges, Art. 14 of regulation No. 714/2009 suggests the consideration of locational signals at the EU level for the electricity market, while Art. 13 of regulation No. 715/2009 requires all Member States to switch to a de-coupled entry/exit regime prohibiting any form of contract-path dependent gas pricing, which was quite common in the past. Only for gas, ACER has announced to work on more specific rules for network tariffs at the TSO-level in order to achieve a better harmonization of tariff structures across Europe.² The greater efforts with regard to gas are due to the fact that the European gas market suffers heavily from differing market rules established in the various Member States, which impedes cross-border trading. Compared to gas, the electricity market is much more integrated.³

Differences in the national regulatory systems, including the fundamental regulatory principles and models, regulatory accounting and the determination of the allowed rate of return, are considered non-crucial, as long as the overall regulatory system in each country ensures sufficient revenues and avoids undue regulatory uncertainty.⁴ Therefore, the decision on the design of the regulatory system for network companies is completely left to Member States. There are no provisions at the EU level, which require

² See ACER (2011). Draft versions of the announced framework guideline on gas tariff methodologies are not publically available yet.

³ See European Commission (2011a).

⁴ See Art. 14 of regulation No. 714/2009 for electricity and Art. 13 of regulation No. 715/2009 for gas. A more detailed analysis of this topic is provided by KEMA (2009).

Member States to opt either for a cost-plus or an incentive-based regulation; nor are they required to apply any kind of cost benchmarking.

2.2 Appeal framework

The EU framework gives some general statements about the possibility to appeal against decisions of the National Regulatory Authority (NRA). These statements are located in the directives 2009/72/EC and 2009/73/EC concerning the common rules for the internal market in natural gas and electricity.

Both directives outline that Energy regulators should have the power to issue binding decisions in relation to electricity/natural gas undertakings and to impose effective, proportionate and dissuasive penalties on electricity/natural gas undertakings which fail to comply with their obligations or to propose that a competent court impose such penalties on them. The directives also see a need for an independent body to which a party affected by the decision of a national regulator has a right to appeal. This means that the regulatory authority's decision shall have binding effects unless it is overruled on appeal.

For this reason and according to Article 37, No. 17 (2009/72/EC) and Article 41, No. 17 (2009/73/EC) "the Member States shall ensure that suitable mechanisms exist at national level under which a party affected by a decision of a regulatory authority has a right of appeal to a body independent of the parties involved and of any government". The independent body could be court or other tribunal empowered to conduct a judicial review.

The EU directives are not a primary law. Member States have to transpose the directives into national law, before they become effective. This means that the specific design of appeal frameworks may differ, but every Member State has to establish a right of appeal against the decisions of the regulatory authority.

3 Distribution system operators

3.1 Austria

3.1.1 Overview of the energy market⁵

Restructuring and liberalization of the Austrian electricity and gas sectors commenced in 1998. The electricity market was fully opened on 1 October 2001 and the gas market one year later. Since liberalization, alternative suppliers have entered both the electricity and gas markets, but concentration has increased in recent years following a series of mergers and joint ventures. Customer switching rates have been low in both sectors, while large industrial customers are the group more likely to choose an alternative supplier.

The key characteristic of the Austrian electricity industry is its high level of public ownership – most businesses are owned by the federal and provincial governments and municipal councils. Most distribution companies in Austria have less than 100.000 customers. Concentration in both the generation and retail segments is relatively high. End-user prices are not regulated and the grid tariffs are fixed by the NRA (E-Control).

The Austrian gas market is divided into three “control areas”, which are not physically connected to each other, although two of the control areas are connected to the German gas network. A large part of the gas transported through the Austrian pipelines is transit. The ratio of transit volumes to domestically consumed gas is about 4 to 1.

3.1.2 Electricity distribution

3.1.2.1 Regulatory regime

Regarding Austrian electricity distribution system operators (DSOs), an incentive regulation is in place since 2006 with two regulatory periods of four years. The first period lasted from 2006 to 2009, the second is from 2010 to 2013.

The overall scheme is a hybrid price cap that has been slightly modified for the second period.⁶ For the first period, the stylised price cap formula was:

⁵ Further information is available at:
<http://www.e-control.at> (the Austrian Energy Regulator),
http://ec.europa.eu/energy/electricity/benchmarking/index_en.htm (Benchmarking Reports),
http://www.ceer-eu.org/portal/page/portal/EREGG_HOME/EREGG_DOCS/NATIONAL_REPORTS/2006 (National Reports), http://www.iern.net/portal/page/portal/IERN_HOME/IERN_ARCHIV/Country_Factsheets/Country%20Factsheet?pld=3070009&pPath1=Europe&pPath2=Austria.

⁶ See Haber (2010).

$$C_t = C_{t-1} \cdot [(1 - X) \cdot (1 + \Delta NPI_t)] \cdot (1 + k \cdot \Delta M_t)$$

With C_t as the total costs in period t, the efficiency factor X , ΔNPI_t as the change in the network operator's price index to account for inflation, k the quantity-cost factor, and ΔM_t the change in the amount of electricity distributed to end-users. The efficiency factor X incorporates the frontier shift due to technological change, X_{gen} (% p.a.), as well as the individual efficiency scores ES (%) determined via benchmarking. The yearly cost adjustment factor X (% p.a.) is calculated as

$$X = 1 - (1 - X_{gen}) \cdot \sqrt[8]{ES}$$

According to E-Control (2006: 27ff.), the Austrian regulator based its decision on the frontier shift on a review of international productivity studies (see Table 1), international practice and own preliminary calculations. Concerning international productivity studies, E-Control identified a range of -1.3% to +3.9% for the frontier shift with only New Zealand showing a negative value. With regard to regulatory practice of international regulators, E-Control reported values for The Netherlands (2% for the first and 1.5% for the second regulatory period), Norway (1.5%) and Finland (2.2%). Based on total factor productivity analysis E-Control calculated an annual frontier shift of 3.5% for Austrian network operators. The data spanned only the period 1996 to 2001, since longer time series of network-related data (not separated into gas and electricity) was not available. After discussions with stakeholders, E-Control has set the frontier shift equal to 1.95% p.a. for the first regulatory period.

Regarding the individual cost reduction requirements, a minimum efficiency score of 74.76% has been decided which results in a maximum cost reduction target of 5.45% p.a. (1.95% frontier shift + 3.5% catch-up). DSOs with actually lower scores are treated as having 74.76%.

The quantity-cost factor was set to $k = 0.5$ as the Austrian regulator, E-Control, assumed that a 1% increase in distributed electricity leads only to a 0.5% increase in costs. Thus, k was a kind of elasticity.

To foster investments (e.g. incorporation of an increasing amount of renewable energy), for the second period the elasticity k has been replaced by a OPEX-factor (BK) and a separate CAPEX-factor (Inv):

$$C_t = C_{t-1} \cdot [(1 - X) \cdot (1 + \Delta NPI_t)] + BK + Inv$$

The frontier shift of 1.95% has not been changed.

Table 1: Overview of empirical studies on productivity used by E-Control

Country	Period	Study	TFP p.a.	Comments
England and Wales	1990/91-1996/97	London Economics (1999)	3.5%	Malmquist Index Frontier shift: 3.9% Catch-up: -0.4% The productivity increase was larger towards the end of the sample period
	1990/91 – 1997/98	Tilley/Weyman-Jones (1999)	6.3%	Tornqvist Index
	1971-1993	Weyman-Jones/Burns (1994)	2.8%	Malmquist Index Frontier shift: 3% Catch-up: -0.2%
	1986-97	Hattori/Jamasb/Pollitt (2003)	3.3% - 6.1%	Different methods applied; strong increase in productivity from 1994 onwards
New South Wales, Australia	1981/82 – 1993/94	London Economics/ESAA (1994)	3.6%	Malmquist Index Labor productivity: 8.1% Cap. productivity: 0.2% Productivity of other factors: 3.7%
Norway	1983-89	Försund/Kittelsen (1998)	1.9%	Malmquist Index Frontier shift: 1.8% Catch-up: 0.1%
	1994-98	ECON (2000)	2.8%	Strongest increase in TFP towards the end of the sample period
	1995-98	NVE (2001)	2.5%	Malquist Index Frontier shift: 2.48% Catch-up: 0.1%
Ontario, Canada	1993-97	OEB (1999)	2.1%	
Spain	1987-97	Arocena/Contin/Huerta (2002)	2.9%	Tornqvist Index
USA	1994-96	London Economics (1999)	0.7%	Malmquist Index Frontier shift: 2.3% Catch-up: -1.6%
	1972-94	Makholm (2003)	1.86%	Productivity varies by region between 0.96% and 2.76%
	1984-94	Makholm (2003)	2.08%	Productivity varies by region between 1.36% and 3.12%
Northern Ireland	1971-94	Competition Commission (2002)	3.1% (5.2% since privatization)	Frontier shift: 3.3% (6.9% since privatization) Catch-up: -0.2%

Source: E-Control (2006: 27f.).

Note: Sources used by E-Control:

Arocena/Contin/Huerta: "Price regulation in the Spanish energy sector: who benefits?". Energy Policy 30, 2002, S. 885-89.

- ECON (2000): "The Nordic electricity reform: Economic and environmental consequences". Working Paper 3/2000.
- Competition Commission (2002): "Northern Ireland Electricity Plc.: A report on a reference under Article 15 of the Electricity (Northern Ireland) Order 1992".
- Førsund/Kittelsen (1998): „Productivity Development of Norwegian Electricity Distribution Utilities“. Resource and Energy Economics 20, p. 207-224.
- Hattori/Jamasb/Pollitt (2003): „A comparison of UK and Japanese electricity distribution performance 1985-1998: lessons for incentive regulation“. DEA Working Paper WP 0212
- London Economics Limited (1999): „Efficiency and benchmarking study of the NSW distribution businesses“. Independent Pricing and Regulatory Tribunal of New South Wales.
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- Makholm (2003): "Price cap plans for electricity distribution companies using TFP analysis"; NERA Working Paper, April 9, 2003.
- NVE (2001): „Den økonomiske reguleringen av nettvirksomheten. Forslag til endring i forskrift om økonomisk og teknisk rapportering, inntektsrammer for nettvirksomheten og overføringstariffer av 11.03.1999 nr. 302“.
- OEB (1999): "Productivity and price performance for electric distributors in Ontario". July 6, 1999.
- Tilley/Weyman-Jones (1999): "Productivity Growth and Efficiency Change in Electricity Distribution". The 1999 BIEE Conference, St. John's College Oxford.
- Weyman-Jones/Burns (1994): "Regulatory Incentives, Privatisation, and Productivity Growth in UK Electricity Distribution". Centre for the Study of Regulated Industries. Technical Paper 1.

3.1.2.2 Efficiency benchmarking

In order to determine the individual efficiency targets (or X-factors), E-Control relies on efficiency benchmarking that is carried out before each regulatory period.⁷ As input variables, total expenditures (TOTEX) are used, i.e. operating expenditures (OPEX) excluding the costs for the usage of upstream networks as well as capital expenditures (CAPEX). CAPEX enter the efficiency benchmarking as declared by the network operators in their cost statements and approved by the regulator in a preceding cost check. No specific cost standardizations are mentioned. Three different approaches are applied, two data envelopment analyses (DEAs) with different output variables and a modified ordinary least squares (MOLS) estimation. This design has been chosen to combine the strengths and weaknesses of deterministic (DEA) and stochastic (MOLS) benchmarking methods. MOLS has been preferred to the stochastic frontier analysis (SFA) due to the small sample. The Austrian efficiency benchmarking is based on around 20 DSOs.

In order to determine the corresponding output variables, (functional) relationships between conceivable structural parameters and costs have been analysed using an engineering-based reference model. The key findings are:

- Cost drivers differ between voltage levels.
- Dimension of transformers depends linearly on the load density (peak load per area served) of all lower voltage levels.
- The relationship between line density (network length per km²) and density of connected customers is non-linear. The functional form is a square root.

⁷ The efficiency benchmarking design for the first and second period has not been changed. See E-Control (2006, 2010).

E-Control added comprehensive regression analysis to check for the significance of other variables that were mostly brought up by industry (e.g. urbanization, share of aerial lines). None of these showed a significant impact (Riechmann and Rodgarkia-Dara 2006).

Three different voltage levels are distinguished, high (HV), medium (MV), and low (LV). Due to the non-linear relationship between line density and density of connected customers, E-Control calculates an analytical network length l for each voltage level j based on data provided by companies

$$l_j = \sum_{i=1}^n \sqrt{N_{j,i} \cdot A_{j,i}}$$

With $N_{j,i}$ as the number of grid connection points of voltage level j in sub-area i and $A_{j,i}$ as the size of sub-area i covered by voltage level j . Thus, the original cost driver of grid connections per area is approximated by a transformed area-weighted network length l_j .

Table 2: Efficiency benchmarking variables in Austria

DEA (I)	DEA (II)	MOLS
<i>Input</i>		
TOTEX	TOTEX	TOTEX
<i>Output</i>		
P_{MV}	P_{MV}	P_{MV}
P_{LV}	P_{LV}	P_{LV}
l_T	l_{HV}	l_T
	l_{MV}	
	l_{LV}	

Two DEA approaches are applied (see Table 2). Both are modelled with constant returns to scale. Furthermore, in both cases the peak load of the medium voltage level (P_{MV}) and the peak load of the low voltage grid (P_{LV}) are used as outputs to capture the dimension of transformers. While DEA (II) includes all three transformed area-weighted network lengths separately, DEA (I) uses an aggregate

$$l_T = 5.83 \cdot l_{HV} + 1.66 \cdot l_{MV} + l_{LV}$$

The weighting factors shall represent cost differences between the three voltage levels and are a result of a stakeholder consultation based on outcomes of the engineering-

based modelling work. E-Control has figured out that DEA (II) suffers from slacks (5 outputs with only 20 observations) overstating efficiency scores of a few DSOs. Using both approaches is a compromise between industry and the regulator.

The MOLS estimation is based on the same variables as DEA (I) according to the following equation

$$\ln C = \beta_1 + \beta_2 \ln l_T + \beta_3 \ln(P_{MV})^2 + \beta_4 \ln P_{LV}$$

The peak load of the MV level enters the equation as a squared term. The final model resulted from various regression runs through elimination of non-significant variables and terms (E-Control 2006: 50). Different model specifications have been tested. All variables entered equations not only as linear terms but also as squared terms in order to capture non-linear effects. Furthermore, interaction terms (product of two different variables) have been incorporated to test if the effect of one variable is significantly modified by another variable. Therefore, the squared peak load of the MV level is just a matter of statistical significance.

The overall efficiency score of an individual DSO, *ES*, is the weighted sum of all three approaches

$$ES = 0.4 \cdot DEA(I) + 0.2 \cdot DEA(II) + 0.4 \cdot MOLS$$

The lower weight for DEA (II) is due to the slack problem.

3.1.3 Gas distribution

3.1.3.1 Regulatory regime

Austria has established an incentive regulation for gas DSOs since 2008 that is quite similar to the regulation of electricity distribution.⁸ The overall cap formula is the same as the current one used for electricity DSOs, i.e.

$$C_t = C_{t-1} \cdot [(1 - X) \cdot (1 + \Delta NPI_t)] + BK + Inv.$$

Due to a higher share of capital, network operators have 10 years to catch up with the frontier (two periods of 5 years). The yearly cost adjustment factor *X* (% p.a.) encompassing the yearly frontier shift X_{gen} (% p.a.) and the efficiency score *ES* (%) is calculated as

$$X = 1 - (1 - X_{gen}) \cdot \sqrt[10]{ES}.$$

⁸ This sub-section is based on E-Control (2008).

The frontier shift is equal to the one of the electricity sector, i.e. 1.95% p.a. for the first regulatory period. The efficiency score is determined via benchmarking. The regulator has set a minimum efficiency score of 74.06% which results in a maximum cost reduction target of 4.85% p.a. (1.95% frontier shift + 2.9% catch-up). DSOs with actually lower scores are treated as having 74.06%.

E-Control distinguishes three network levels

- Level 1: Long distance gas transport
- Level 2: High pressure gas distribution (over 6 bar)
- Level 3: Low pressure gas distribution (less than 6 bar).

Similar to electricity, the three levels show different cost characteristics with level 1 being most distinct (e.g. a much higher impact of pipeline diameters on costs). As only 20 companies are operating the Austrian gas grid, the regulator had to decide how to tackle the different levels under the efficiency benchmarking taking into account the small sample and the heterogeneity of network operators. Most of the companies are covering more than one level with five being active in level 1. Out of these five, only OMV is solely operating level 1 and can be classified as a pure TSO. Thus, E-Control exempted OMV from incentive regulation and includes information on the other two levels in the efficiency benchmarking. For the remaining four companies of level 1, the efficiency scores of the benchmarking based on cost information of level 2 and/or level 3 are equally applied to their level 1 costs.

3.1.3.2 Efficiency benchmarking

The efficiency benchmarking is based on TOTEX (input) of a certain base year. OPEX are directly taken from the last available profit and loss accounts (2006), i.e. labour, material and other operating expenditures less metering costs and the costs for the usage of upstream networks. Regarding capital costs, E-Control decided on a split weighted average cost of capital (WACC), 6.51% for investments prior 2008 and 6.97% thereafter (both nominal pre-tax). Besides different investment cycles, companies show a heterogeneous behaviour of handling investments in their balance sheets (depreciation period and recognition of assets). However, only for pipelines some standardization has been carried out, while information for the other assets is also taken from the profit and loss accounts as the latter represent a minor share of total CAPEX. Two different standardization methods for pipelines are applied

- Indexed historic costs,
- Annuities.⁹

⁹ E-Control provides no reasoning why CAPEX treatment is different from electricity. One reason could be that the mentioned problems with regard to investment handling are less crucial for electricity distribution.

Indexed historic costs represent inflation-adjusted capital cost and correspond to the accounting principle of replacement values. First, historic investment values are inflated to the base year of the efficiency benchmarking, i.e. 2005. As no pipeline-specific price index was available, E-Control used the consumer price index without complaints of the industry. Second, based on these inflated investment values, depreciation and the remaining depreciated investment values are calculated applying the same lifetime of 40 years for all pipeline investments. Third, a WACC in real terms (nominal WACC minus inflation) is applied to the remaining depreciated investment values to determine the return on investment. In this context, inflation is reimbursed via depreciation and not via the return on investment.

Annuities follow the same principle of replacement values. Instead of determining depreciation and the return on investment separately, constant amounts (annuities) are calculated assuming the same duration (40 years) and WACC (in real terms) as for the indexed historic costs. This results in an equal valuation of past and current investments. Therefore, results of the efficiency benchmarking are independent of actual investment cycles. On the other hand, higher operating cost, which are usually related to older networks, are not taken into account.

With regard to outputs, the preceding engineering-based modelling has not resulted in a clear picture about cost structures and the choice of output variables. Thus, E-Control defined three broader categories (transport of energy, supply of capacity and service of customers) for which different variables have been tested using correlation and regression analysis. Instead of transformed area-weighted network lengths, actual network lengths are entering the efficiency benchmarking. The networks of the different pressure levels are combined to one single variable through weighting. The corresponding weighting factors are results of estimations based on actual capital costs. The factors depend on pipeline dimension and range from 4.22 for level-2-pipelines with diameters above 600 inch to 1 for level-1-pipelines with diameters of less than 300 inch.

Extensive pre-testing of various other variables resulted in two final models entering the efficiency benchmarking

Model 1

- Input: TOTEX using indexed historic costs for CAPEX
- Outputs
 - Weighted network length
 - Peak load industrial customers
 - Metering points residential customers

Model 2

- Input: TOTEX using annuity costs for CAPEX
- Outputs
 - Weighted network length
 - Peak load industrial customers
 - Metering points residential customers

For both models, DEA and MOLS are applied with the following specifications

- DEA: constant returns to scale with imposing the restriction of a 75%-limit on the maximum input/output contribution.
- MOLS: log-linear cost function with imposing the restriction of constant returns to scale.

Constant returns to scale are used since E-Control assumes that company size is endogenous. In contrast to electricity, this assumption is introduced for both methods. Regarding DEA, the restriction of a 75%-limit on the maximum input/output contribution is intended to reduce the slack problem.

Table 3: Correlation of efficiency scores between DEA and MOLS

	DEA (Model 1)	DEA (Model 2)	DEA (Average)
MOLS (Model 1)	0.95	0.95	0.95
MOLS (Model 2)	0.96	0.96	0.96
MOLS (Average)	0.95	0.96	0.96

Source: E-Control (2008: 50).

The efficiency scores of the two DEA models and of the two MOLS models are nearly perfectly correlated with 99.52% for DEA and 99.54% for MOLS (within-correlation). Moreover, correlation between the different methods are well above 90% (see Table 3).

The final efficiency score is determined in two steps. First, for both methods the score of the two models is simply averaged (e.g. $DEA = 0.5[(DEA(1)+DEA(2))]$). Second, the higher average score is weighted with 60% and the lower with 40%

$$ES = 0.6 \cdot \max(DEA, MOLS) + 0.4 \cdot \min(DEA, MOLS)$$

The weighting of the different approaches is a compromise between industry and the regulator. Originally, the regulator argued in favour of an equal weighting of DEA(average) and MOLS(average), whereas the industry preferred a best-off calculation, which means that the highest score of all four models should be used to determine the cost reduction requirements.

3.1.4 Appeal framework¹⁰

In Austria the regulatory function is shared between Energy Control Ltd (E-Control, a state-owned company) and the Energy Control Commission. The latter is also the appeal body against decisions of the former. The successive competence for judicial review is held by civil courts, which apply the civil procedure act implying some limitations such as the prohibition of introduction of new evidence. After exhaustion of all stages of appeal, an action is possible before the administrative and Constitutional courts. It is to be noted that the civil courts often lack technical expertise. Half the judgments of the civil courts deviate from the decisions adopted by the regulator. Another drawback is linked with the decentralization of regulatory decisions, increasing legal uncertainty. There are reform plans for the creation of specialized chambers in the administrative court as a second instance, while the E-Control Commission would be the first instance.

¹⁰ For the following see FSR (2008).

3.2 Denmark

3.2.1 Overview of the energy market¹¹

The liberalization of the Danish electricity and gas markets commenced in the late 1990s. Both markets are fully open to competition, but remain highly concentrated with electricity generation and the gas market being dominated by a single state-owned entity. There is a separate electricity and gas transmission system operator, which is owned by the Danish state, while supply and distribution companies have been legally unbundled. Supplier switching is fairly common among large customers, but is much more limited for small companies and households, which have the option of staying within a regulated tariff with a 'default supplier'.

The Danish electricity market is very concentrated and dominated by two main generating companies (DONG Energy and Vattenfall), one of which is also the main player in the gas market. Both companies are state-owned, whereby DONG is owned by the Danish State and Vattenfall by the Swedish State. Denmark plays a key role for transit between Nordic hydro-based power systems and continental thermal power systems. The electricity TSO is Energinet.dk, which is also owned by the Danish State. The distribution sub-sector has mixed ownership: State ownership for those owned by DONG Energy, municipal ownership or cooperatives consisting of the local network users. Legal and functional unbundling are required for DSOs. The wholesale market is integrated with the Nordic power market (consisting of Denmark, Finland, Sweden and Norway). On the retail side, there is competition for large and medium-sized customers, many of which have changed supplier or re-negotiated their contract with their existing supplier. On the other hand, switching among smaller customers has been much weaker.

Denmark is a gas producing and exporting country with production located in the Danish part of the North Sea. The gas market is highly concentrated and is dominated by a single state owned entity. The transmission network on land is owned and operated by the state-owned TSO Energinet.dk. Three gas DSOs operate at the distribution level. Legal and functional unbundling are required for network companies. There is some competition in the retail market, especially for larger customers, but again the sector is dominated by the abovementioned state-owned entity. Household customers have almost exclusively remained on the regulated default tariff, which is much lower than rates offered in the competitive market.

¹¹ Further information is available at:
<http://www.energitilsynet.dk> (the Danish Energy Regulator),
http://ec.europa.eu/energy/electricity/benchmarking/index_en.htm (Benchmarking Reports),
http://www.ceer-eu.org/portal/page/portal/ERGEG_HOME/ERGEG_DOCS/NATIONAL_REPORTS/2006 (National Reports),
http://www.iern.net/portal/page/portal/IERN_HOME/IERN_ARCHIV/Country_Factsheets/Country%20Factsheet?pId=3070017&pPath1=Europe&pPath2=Denmark.

3.2.2 Electricity distribution

3.2.2.1 Regulatory regime

Due to several mergers, the number of Danish electricity distribution companies has decreased from 107 in 2006 to 77 in 2011 (DERA 2011). Danish DSOs operate under a price cap regulation.¹² Energitilsynet, the Danish Energy Regulatory Authority (DERA), has developed an efficiency benchmarking, the so-called net volume (or netvolumen) model, which is performed annually. The main feature of the model is a cost index measuring the costs of an average DSO running a specific grid. The purpose of the model is to compare electricity DSOs despite differences in size and the surrounding environment.

The net volume model is accompanied by a quality of supply benchmarking that is also performed annually (Hansen 2011). The assessment is based on the DSOs' System Average Interruption Frequency Index (SAIFI) and System Average Duration Frequency Index (SAIDI). Unplanned interruptions are weighted with 100 %, planned interruptions with 50 %, and interruptions caused by third party with 10 %. System outages due to force majeure are not considered. The 20% of DSOs having the highest weighted SAIFI receive a malus of up to 1% of the allowed operational costs. Likewise, the 20% of DSOs having the highest weighted SAIDI receive a malus of up to 1% of the allowed operational costs. Hence, the reduction of the allowed OPEX of a certain DSO is limited to 2%.

To avoid significantly lower supply qualities in rural areas, system operators are additionally punished if 1% of their customers experience more system outages during a year than the Danish average (so-called worst served customers). This additional quality element has been applied in 2010 for the first time. In this context, three electricity DSOs (out of 77) have received a corresponding revenue reduction.

3.2.2.2 Efficiency benchmarking

Annually, each DSO has to report its stock of 23 different types of components installed in its distribution network (e.g. kilometres of power cables). DERA has calculated cost equivalents for each of these 23 types by estimating the average unit operational costs and the average unit costs of depreciation. For each DSO, DERA first multiplies the DSO's stock with the corresponding unit operational cost and unit depreciation cost. The DSO's so-called netvolumen is just the sum over the 23 network components

$$netvolumen_j = \sum_{i=1}^{23} net_component_{i,j} \cdot (Uope_i + Udep_i)$$

¹² Further information on the price cap regulation was not available.

with:

- $netvolumen_j$ as the sum of the 23 network components for DSO j .
- $net_component_{i,j}$ as DSO $_j$'s stock of component i .
- $Uope_i$ as the average unit operational cost for component i .
- $Udep_i$ as the average unit depreciation cost for component i .

For a given DSO $_j$, the $netvolumen$ measures the cost level that an average DSO would have when operating the DSO $_j$'s distribution network.

Each DSO also reports its actual total operational costs and total costs of depreciation. Based on these reported costs, a cost-index is calculated for each DSO:

$$\text{Cost - index}_j = \frac{(\text{Operational cost}_j + \text{Depreciation of capital}_j)}{\text{Netvolumen}_j}$$

According to previous experiences, operational costs are higher in densely populated areas than in scarcely populated areas. Therefore, the cost-index is adjusted for variations in population density.

DERA applies an average of the top 10% most cost-efficient DSOs to benchmark the cost-efficiency of the remaining 90%. Based on this efficiency benchmarking, DERA sets an annual efficiency target implying that inefficient DSOs have to become at least as cost-efficient as the average of the top ten most cost-efficient DSOs within a five year period. The efficiency requirements are calculated annually based on data of the previous year.

Table 4: Development of the average efficiency potential

	Average cost-index for best practice	Average efficiency potential
2007	0.68	0.32
2008	0.71	0.32
2009	0.65	0.39
2010	0.67	0.33

Source: DERA (2011).

DERA has figured out that the average efficiency potential as the main result of the efficiency benchmarking remains more or less constant over time (see Table 4).

3.2.3 Appeal framework¹³

The Danish Energy Regulatory Authority is the supervisory body in respect of the regulated areas of the energy sector. In Denmark pricing as well as other terms and conditions of transmission and distribution services must be notified by network operators to the Danish Energy Regulatory Authority. Prices charged by network operators must be established according to fair, objective, and non-discriminatory principles in consideration of the costs of the companies. DERA may alter prices, terms or conditions if they are deemed in contravention of the Energy Law or are deemed to result in an environmentally or economically inappropriate utilization of energy. DERA may at any time start investigations and may order companies to give all necessary information. As a first step, all complaints on tariffs, terms and other regulations are handled by DERA. DERA's decisions may be appealed to the Energy Board of Appeal, and finally be brought to Court.

Non-regulated areas are within the aegis of the Danish Competition Authority. Decisions may be appealed to the Danish Competition Appeals Tribunal. Consumer protection rules apply in respect of contracts for energy supply. The Energy Supplies Complaint Board hears disputes arising out of contracts between consumers and supply companies.

¹³ For the following see Svensson and Kirkegaard (2011).

3.3 Finland

3.3.1 Overview of the energy market

The reform and deregulation of the Finnish electricity market commenced in 1995 and was fully opened in January 1997. The electricity transmission system operator is ownership unbundled, although part of the ownership remains within vertically integrated generation/distribution businesses. The retail electricity market is considered to be among the most competitive ones in the EU as demonstrated by the relatively high customer switching rates.

The Finnish electricity generation sector is characterized by a large number of actors. There is no separate Finnish wholesale electricity market; together with Sweden, Norway and Denmark, Finland makes up a single Nordic wholesale market. Fingrid Plc. is the independent TSO (24% state-owned). Customer switching is frequent, especially among large customers, although there is some evidence of large price differences in the market suggesting that competition could be further developed.

The Finnish natural gas market is relatively small and isolated. All natural gas consumed in Finland is imported from Russia. No pipeline connections to other neighboring countries exist. There are no production or storage facilities in Finland. Gasum Ltd. is the only importer and wholesale supplier, and it also owns the transmission network. Its ownership is divided between the State of Finland, Fortum Plc., E.ON Ruhrgas and Gazprom. Finland has an exemption from the gas directives, which is effective as long as Finland does not have a direct connection to the gas network of any other Member State and has only one main natural gas supplier.

3.3.2 Electricity distribution

3.3.2.1 Regulatory regime

In 2009 there were 88 DSOs operating in Finland. They are entitled to set their network tariffs by themselves but must follow methods determined ex-ante by the Finnish regulator Energiamarkkinavirasto (“Energy Market Authority (EMA)”)¹⁴ These methods concern the calculation of both Capex and Opex.

Concerning Capex, the rate of return is calculated using the Capital Asset Pricing Model (CAPM). The EMA calculates “a reasonable return on the return on capital invested in

¹⁴ Energiamarkkinavirasto (2011).

electricity network operations ($R_{k,post-tax}$) in the year i after imputed corporation taxes according to the following formula:¹⁵

$$R_{k,post-tax,i} = \left(C_{E,i} \times \frac{70}{100} + C_{D,i} \times (1 - t_i) \right) \times (D_i + E_i)$$

In the formula, the reasonable cost of equity invested in network operations in the year i ($C_{E,i}$) will be calculated with the following formula:

$$C_{E,i} = R_{r,i} + \beta_{asset} \times \left(1 + (1 - t_i) \times \frac{30}{70} \right) \times (R_m - R_r) + LP$$

In the formula, the reasonable cost of interest-bearing debts invested in network operations in the year i ($C_{D,i}$) will be calculated with the following formula:

$$C_{D,i} = R_{r,i} + 0.6\%$$

In the above formulae

$R_{k,post-tax,i}$	=	A reasonable return (EUR) on electricity network operations after corporation tax in the year i
$C_{E,i}$	=	Reasonable cost of equity in the year i
$C_{D,i}$	=	Reasonable cost of interest-bearing debts in the year i
t_i	=	Corporation tax rate in the year i
D_i	=	Amount of interest-bearing debts invested in network operations at the end of year i
E_i	=	Amount of equity invested in network operations at the end of year i
$R_{r,i}$	=	Risk-free rate applied to the year i
β_{asset}	=	The asset beta
$R_m - R_r$	=	Market risk premium
LP	=	Premium for lack of liquidity"

On the other hand, EMA sets individual efficiency targets concerning OPEX. The amount of controllable operational costs of network operator i in accordance with the efficiency target for 2008 ($SCO_{2008,i}$) is calculated with the following formula:¹⁶

¹⁵ Ibid.

¹⁶ Ibid.

$$SCO_{i,2008} = (1 + \Delta BCI_{2008}) \times (1 + \Delta K_{i,2008}) \times (1 - X_{yl}) \times (1 - XV_{yr,i}) \times CO_{i,2003-2006,ka}$$

where

$SCO_{i,2008}$ = The controllable operational costs of network operator i in accordance with the efficiency target for the year 2008

$\Delta K_{i,2008}$ = Change in the extent of the network (network volume) of network operator i for the year 2008.

ΔBCI_{2008} = Change in the building cost index for the year 2008.

X_{yl} = General efficiency target for the second regulatory period

$XV_{yr,i}$ = Annual enterprise-specific efficiency target adjusted by the error margin coefficient and the OPEX/TOTEX ratio set for network operator i for the second regulatory period

$CO_{i,2003-2006,ka}$ = The average actual controllable operational costs in accordance with the unbundled confirmed financial statements of network operator i for 2003–2006, adjusted to the 2007 price level.

The amount of controllable operational costs of network operator i in accordance with the efficiency target for the following years of the regulatory period (2009–2011) for the year t ($SCO_{i,t}$) is calculated with the following formula:

$$SCO_{i,t} = (1 + \Delta BCI_t) \times (1 + \Delta K_{i,t}) \times (1 - X_{yl}) \times (1 - XV_{yr,i}) \times SCO_{i,t}$$

where

$SCO_{i,t}$ = The controllable operational costs of network operator i in accordance with the efficiency target for the year t

$\Delta K_{i,t}$ = Change in the extent of the network (network volume) of network operator i for the year t.

ΔBCI_t = Change in the building cost index for the year t.

X_{yl} = General efficiency target for the second regulatory period

$XV_{yr,i}$ = Annual enterprise-specific efficiency target adjusted by the error margin coefficient and the OPEX/TOTEX ratio set for network operator i for the second regulatory period

3.3.2.2 Efficiency benchmarking

Based on different studies, the EMA uses both DEA as well as SFA for the efficiency benchmarking of distribution network operators. Both methods are used because it became clear that both DEA and SFA have some strengths and weaknesses. The outcomes of the efficiency comparison are applied to the regulation period from 1 January 2008 to 31 December 2011.

A DEA model has been developed already since the year 1998. The current model is mainly based on a study of Lappeenranta University of Technology from December 2006.¹⁷ The input and output factors of the current DEA model are: ¹⁸

Input factor(s): the overall costs to the customers, which are composed of the sum total of controllable operational costs, depreciations and outage costs.

Output factors: the total length of the electricity network, number of users of the network operator and the value of energy distributed to consumption.

EMA is convinced that using the sum of total costs as input factor is most suitable to develop the entire network operations towards a socio-economic optimum. Using only the operational costs as input factor had led to some difficulties in previous DEA models. In particular, grid operators obviously focussed on reducing controllable operational costs which lead to an increase in other cost factors. Therefore, the previous DEA model seemed to set some distorting incentives concerning cost cutting efforts by grid operators and was followed by the new DEA model which uses a total cost approach. This is also the rationale for considering outage costs as part of total costs. Assume two identical DSOs, which only differ in system outages. Neglecting outage costs would lead to identical efficiency scores for both DSOs, whereas the current model gives the company with lower outages a higher score. Therefore, the current model covers both the cost (in terms of private production costs) and the quality of service performance. If the quality issue was not taken into account, the incentives would be biased towards reductions in private production costs (at the expense of service quality).¹⁹

Data for the efficiency benchmark of the current regulatory period (input and output factors) are the average values for the years 2003 to 2006 whenever available. "Otherwise a time series which is as long as possible,"²⁰ is used. By using average values EMA hopes to smoothen effects that occur through random variation. Basis for

¹⁷ EMA commissioned a study to evaluate the DEA model used since 1998. This study was carried out by the Lappeenranta University of Technology and the Tampere University of Technology under the lead of the former. For the final report of this study see Honkapuro et al. (2006). The major change to the previous DEA model is the consideration of total costs including outage costs.

¹⁸ See in the following: Energiamarkkinavirasto (without date).

¹⁹ The reasoning corresponds to the discussions why an incentive regulation should be accompanied by a quality of service regulation.

²⁰ Ibid.

the data are profit and loss accounts in the financial statements of the companies. Controllable operational cost are:

- Materials, accessories and energy purchases
- + Increase or decrease in stocks
- + Staff costs
- + Rents
- + Other external services
- + Internal costs (with respect to 2005 and 2006)
- + Other costs
- + Standard compensations paid (if not included in other costs)
- Production for own use

“In the benchmarking, the average for imputed straight-line depreciations for the electricity network for 2005–2007 determined in the first regulatory period is used as straight-line depreciations included in the input factor.”²¹ Concerning the outage costs, data from the years 2005 and 2006 is used to calculate this part of the input factor. EMA may also take into account data of a longer time series (i.e. 2003 to 2006). This may happen by request of the single network operators. Finally, “the controllable operational costs for 2003–2006, the straight-line depreciations for 2005–2007 and the outage costs in 2005 and 2006 ...[are]... adjusted to correspond to the 2007 price level.”²²

Concerning the output factors, the following data is used:

- Network length: Average total length of the electricity network in 2003 – 2006
- Number of network operator’s customers: Average number for 2003 – 2006
- Amount of energy distributed to consumption: Average for 2003 – 2006 of energy distributed to consumption, multiplied by the average electricity distribution prices for various voltage levels in each year (values are then adjusted to 2007 price levels)

Finally, the formula of the DEA model used by EMA is the following:

$$DEA(-Score) = \frac{u1 \times Energy + u2 \times Networklength + u3 \times Customers}{v1 \times (OPEX + SLD + DCO)}$$

with OPEX: controllable operational costs
 SLD: straight-line depreciations
 DCO: disadvantage to the customer caused by electricity supply outages
 u1-3, v: internal weight factors

²¹ Ibid.

²² Ibid.

The internal weight factors are necessary when several input and output factors are used in the DEA.²³

Concerning returns to scale assumptions that have to be made in a DEA model, EMA has decided to use the non-decreasing returns to scale assumption (NDRS) for the following reasons: The use of a constant-return to scale model (CRS) has shown that the smallest network operators will suffer from heavy disadvantages in the efficiency benchmarking under this assumption. Furthermore, using CRS means that it is assumed that (inefficient) network operators can change their scale in the long run in order to produce at a least cost optimum, i.e. at an optimal scale. However, in the short run the NDRS makes it possible for small network operators to reach an efficient level. The variable returns to scale model (VRS), which favours small and large network operators in the efficiency benchmarking (assuming that both have scale disadvantages), is not applied because using the NDRS did not lead to any disadvantages for large network operators in the efficiency benchmarking.

Concerning the use of an input or output oriented approach, EMA argues as follows: “It is assumed in the input-oriented DEA model that a measured unit may only change the use of inputs, in which case the efficiency figure will tell how much the enterprise must reduce the use of inputs in order to achieve an efficient front. On the other hand, it is assumed in the output-oriented model that a measured unit may only change the outputs while the use of input will remain unchanged, in which case the efficiency figure will tell how much the enterprise must increase outputs in order to achieve an efficient front. In practice, the network operator is unable to have much of an impact with its own operations on the number of output factors used in the model, and therefore the use of input-oriented version of the model is justified.”²⁴ The EMA has therefore decided to use the input-oriented version of the model.

The SFA model used by EMA uses output factors that are slightly different from those applied in the DEA model because results calculated that way showed that the average efficiency of network operators in urban areas was lower than that of network operators mainly operating in rural conditions. Therefore the output variable network length has been divided into two variables, urban network and other network, based on the ditching degree as an indicator for urban environment. The input variables are the same as in the DEA model (opex, depreciation and interruption cost).²⁵

This means that “...the Energy Market Authority will use two output variables, i.e. the length of the urban network and other network, as the factors describing the dispersion of customers in the SFA model. The total length of the network operator’s 0.4 kV and 20 kV underground cables in an urban area will be used as the length of the urban network in the SFA model. This will be calculated as an average of the data material delivered

²³ A more detailed discussion on the internal weight factors can be found in: Lassila et al.(2003).

²⁴ Energiämarkkinavirasto (without date).

²⁵ Syrjänen, Bogetoft, Agrell (2006).

by the network operators on the assessment of the value of capital invested in the network during the first regulatory period in 2005–2007. Otherwise, the Energy Market Authority will use the same variable as those in the DEA model as the variables in the SFA model.”²⁶

EMA uses the “linear functional form in the SFA model.”²⁷ Furthermore, non-decreasing returns to scale (NDRS) are applied for the same reasons as with the DEA model: “The efficiencies of these [smaller] network operators are lower on average than those of other network operators when calculated with the constant returns to scale models. The NDRS model takes the disadvantage of scale of the smaller network operators into account by adding the standard term to the function. The standard term included in the model is statistically significant. It can also be deducted that the results of the model will correspond better to the level that the network operators have an actual opportunity to reach. Furthermore, the Energy Market Authority considers that it can also be regarded as a generally accepted idea that business operations require a certain amount of start-up costs before any output can be achieved.”

To reduce uncertainties from both methods (DEA and SFA), EMA decided to use the outcomes of both efficiency assessments. The enterprise specific efficiency-figures are therefore calculated as the average of the figures calculated with DEA and SFA with the following formula:

$$EF_{ent,i} = \frac{DEA_i + SFA_i}{2}$$

With $EF_{ent,i}$ = Enterprise-specific efficiency figure for network operator i

DEA_i = Efficiency figure calculated for network operator i with the DEA model

SFA_i = Efficiency figure calculated for network operator i with the SFA model

“As both methods used in the efficiency measurement are input-oriented, the result of the above formula indicates how much the network operator should reduce costs that are used as input so that the network operator would achieve a cost level complying with efficient operations. Therefore, the efficiency target of network operator i (ET_i) can be presented with the following formula”²⁸

$$ET_i = 1 - Ef_{ent,i}$$

²⁶ Energiamarkkinavirasto (without date).

²⁷ Ibid.

²⁸ Ibid.

3.3.3 Appeal framework

The Energy Market Authority is mandated to issue both administrative decisions and administrative regulations.²⁹ On the basis of the Electricity Market Act and the Natural Gas Market Act, the Energy Market Authority is empowered to issue administrative regulations on certain clearly defined issues that are not subject to appeal. The administrative regulations are binding on all the entrepreneurs, which are active in the defined fields (for instance electricity distribution network operators, natural gas distribution network operators, and retail companies). The administrative regulations cover the following issues:

- a regulation instructing the network operators on how and when to submit unbundled accounting information to the Energy Market Authority;
- a regulation on more detailed instructions on what information and which key figures the network operator has to publish and how the publication shall be carried out;
- a regulation on the publication of technical key figures of the network operation;
- a regulation on the itemization of bills;
- a regulation instructing the retail suppliers on how to publish and inform prices as well as sales terms and conditions; and
- a regulation instructing the network operators on how to publish and inform prices as well as sales terms and conditions.

The administrative decisions cover all issues related to the ratemaking of network operators, which are described in the sub-sections 3.3.2.1 and 3.3.2.2 (e.g. the determination of the cost of capital). These administrative decisions are subject to appeal with the first appellate level being either the Market Court (market supervision issues) or the Administrative Courts (licence issues). The final appeal body in both cases is the Supreme Administrative Court. The Ministry of Trade and Industry cannot interfere or influence these administrative decisions by the Authority, as they can only be appealed to the Market Court or Administrative Courts and finally to the Supreme Administrative Court.

²⁹ For the following see Energiamarkkinavirasto (2006, 2011).

3.4 Germany

3.4.1 Overview of the energy market³⁰

The German electricity and gas markets were fully opened to competition in 1998. The large electricity and gas network operators are legally unbundled and some even ownership unbundled. German customers pay prices for electricity and gas that are among the highest in the EU.

As far as the Federal Cartel Office is aware, the market at electricity generation level is still dominated by a few companies. But this structure is currently changing. Germany has defined a phase-out policy of nuclear power by 2022. Considerable growth in the use of renewable energy sources in Germany, particularly wind, conducts to lower the concentration. An obligation exists on network operators to purchase a proportion of their electricity from renewable sources.

Germany is the second largest gas consumer in the EU after the United Kingdom. With a relatively small rate of domestic production, Germany imports the vast majority of its gas volumes from Russia, Norway and the Netherlands. All of Germany's gas imports are being accomplished via pipeline, so far there are no LNG imports. The national grid is interconnected with foreign pipelines through international cross border points with Austria, Belgium, Czech Rep., Denmark, Luxemburg, France, Netherlands, Norway, Poland and Switzerland. There are several planned or just realized pipeline projects on the German market: The OPAL (Ostsee Pipeline Anbindungsleitung) and NEL (Norddeutsche Erdgasleitung) pipelines are intended to transport approximately 55 bcm/year of natural gas imported via the Nord Stream pipeline. Both pipelines are planned to be built through the collaboration of WINGAS and E.ON Ruhrgas. The pipelines will be operated by OPAL NEL TRANSPORT GmbH and E.ON Ruhrgas Nord Stream Anbindungsleitungsgesellschaft mbH.

30 Further information is available at:
www.bundesnetzagentur.de (the German Energy Regulator),
http://ec.europa.eu/energy/electricity/benchmarking/index_en.htm (Benchmarking Reports),
http://www.ceereu.org/portal/page/portal/EREG_HOME/EREG_DOCS/NATIONAL_REPORTS/2006 (National Reports),
http://www.iern.net/portal/page/portal/IERN_HOME/IERN_ARCHIV/Country_Factsheets/Country%20Factsheet?pld=3070023&pPath1=Europe&pPath2=Germany.

3.4.2 Electricity distribution

3.4.2.1 Regulatory regime

Germany has established incentive regulations for electricity DSOs since 2009 that is designed as revenue cap. The basic formula for allowed revenues R is

$$R_t = C_{ex,t} + [C_{en,0} + (1 - d_t) \cdot C_{i,0}] \cdot (i_t - x_{gen,t}) \cdot ef_t$$

Three cost categories are distinguished. $C_{ex,t}$ are regarded as being exogenous to the network operator's core activities (e.g. charges for upstream networks, concessions, taxes etc.). Thus, no cost reduction requirements are applied. These costs stay outside of the efficiency benchmarking and are updated yearly. The other two categories are linked with the network operator's business (e.g. material, staff, capital costs etc.) and enter the efficiency benchmarking. The identified inefficiencies ($C_{i,0}$) have to be completely removed over two regulatory periods. Electricity has two periods of five years. The removal of inefficiencies is linearly distributed over the whole period via the distribution factor d_t . E.g., for an electricity DSO the corresponding factors of the first regulatory period are $(1-d_1)=0.9$, $(1-d_2)=0.8, \dots$, $(1-d_5)=0.5$. The initial benchmarking score determines the cost share attributed to inefficiencies and the efficient cost level $C_{en,0}$. i_t is the inflation rate calculated as the change of the consumer price index and $x_{gen,t}$ is the cost reduction requirement due to technological change (frontier shift).

One characteristic of the German energy network industry is the high number of distribution system operators. Germany has 866 electricity DSOs with over 90% (790) having less than 100,000 connected customers. The regulatory treatment of DSOs is shared between the Federal and the sub-national ("Länder") level. The BNetzA as the Federal regulator covers all DSOs with more than 100,000 customers. This threshold corresponds with European law. Art. 26 Sec. 4 of the electricity Directive allows for lower unbundling requirements for DSOs serving less than 100,000 customers. However, sub-national regulators can delegate responsibilities to the Federal regulator. A second threshold for small DSOs is mentioned by the ordinance on incentive regulation. Operators with less than 30,000 customers have the choice between a simplified procedure and the full-fledged efficiency benchmarking. If they opt for the simplified approach, they face lower information requirements. E.g., without any proof 45% of total costs are regarded as exogenous ($C_{ex,t}$), and thus are exempted from any reduction requirements. On the other hand, an efficiency score of only 87.5% is assumed for the remaining cost share.

The incentive regulation incorporates some additional elements to foster investments, e.g. the so-called enlargement factor ef_t and the investment budget. The enlargement factor covers changes of the DSO's requirement to supply customers. The investment

budget captures other capital costs associated with network restructuring requirements (e.g. due to a de-industrialization in Eastern Germany).³¹ While in the first year of the regulation the German regulator, the Federal Network Agency (Bundesnetzagentur, BNetzA), approved some requests for an investment budget, it denied their approval thereafter. The reason is that the regulator adjusted the enlargement factor for 2010, now encompassing the number of connection points of distributed generation capacity (e.g. wind and photovoltaic). As the investment budget is sub-ordinated to the enlargement factor, the BNetzA argues that the relevant costs for network extensions at the DSO-level to connect an increasing amount of renewable energy sources is now sufficiently covered by the enlargement factor. Thus, the investment budget has become an issue at the TSO-level rather than at the DSO-level. An accompanying quality regulation for electricity is expected to start 2012. It will be a bonus/malus regime based on indices (the System Average Interruption Duration Index, SAIDI, for the low voltage level and the Average System Interruption Duration Index, ASIDI, for the medium voltage level) referenced to a base period of three years to smoothen random effects. To account for uncertainties, the bonus or malus is capped to 2 - 4% of allowed revenues of an operator. The cap is determined by the regulator ex post and due to an intended revenue-neutral design over all affected DSOs.³²

A highly controversial issue has been the determination of the frontier shift $x_{gen,t}$. In the German context, $x_{gen,t}$ consists of two elements, an input price differential and a productivity differential.³³ The former captures the difference of input price developments between the network industry and the overall economy. The latter measures the corresponding difference of productivity developments. In the consultations preceding the regulation both sides, the regulator and the network operators, disputed actively about the right level. Not surprisingly, the regulator argued in favour of higher values (i.e. higher cost reduction requirements), whereas industry opposed these efforts arguing for zero or even negative values allowing for an increase in revenues. BNetzA started with claiming a value of 2.54% based on calculations applying index numbers (Törnquist). Several studies commissioned by industry associations using different data sources and base periods concluded much lower values. The main problem regarding the calculation is the absence of valid data.³⁴ As no agreement had been reached, the Federal Ministry of Economics, in charge of designing the corresponding ordinance, decided on values somewhere in-between. For the first regulatory period, the frontier shift has been set to 1.25% p.a., and for the second period to 1.5% p.a.. Besides many other aspects, industry has taken legal action against the setting of the frontier shift. On June 28, 2011, the High Court finally

³¹ The investment budget covers only capital costs that are excluded from any cost reduction requirements for a certain period of time. Hence, these capital costs become an element of the cost category $C_{ex,t}$ and are actually treated as being cost-plus regulated. For details see BNetzA (2010).

³² See e.g. Westermann and Krämer (2011).

³³ For details see Stronzik (2006).

³⁴ Longer time series data on network-specific information is not provided by the Federal Statistical Office.

decided that the determination is not in line with existing energy law. According to the court, the energy law, that is superior to the incentive regulation ordinance, does not allow for a revenue reducing setting of the productivity differential. On the other hand, accounting for different input price developments has been judged lawful. The court has asked the regulator to re-calculate the input price differential. The regulator and network operators are currently discussing possible solutions.

3.4.2.2 Efficiency benchmarking

The current efficiency benchmarking design of electricity DSOs is an outcome of the following steps

- Engineering based reference network modelling to identify possible cost drivers,³⁵
- A preliminary efficiency benchmarking study,³⁶
- Several rounds of stakeholder consultations and
- Final efficiency benchmarking study for electricity.³⁷

Due to the above mentioned sharing of responsibilities between the BNetzA and sub-national regulators and the option for small network operators with less than 30,000 connected customers, 198 DSOs have actually entered the current efficiency benchmarking. The approach is based on TOTEX (input). Network operators have very different investment cycles, apply different depreciation periods, and recognition of assets in cost calculations varies significantly across DSOs. E.g., while networks in West Germany are usually quite old, networks in the Eastern part have been substantially modernized after 1990. Thus, besides cost information provided by the companies, the BNetzA has carried out a standardization of capital costs (see BNetzA 2006: 160ff.). Based on information of physical assets, equal depreciation periods have been applied for certain assets specified in Appendix 1 of the ordinance on tariffs (*Stromnetzentgeltverordnung, StromNEV*). Using information on the actual year of asset acquisition, the remaining asset values have been calculated. Finally, based on the WACC specified in the ordinance on tariffs, the resulting costs of capital have been computed. Moreover, the German efficiency benchmarking consists of two methods, DEA and SFA. According to Appendix 3 of the incentive regulation ordinance and to protect small DSOs, a DEA with non-decreasing returns to scale (NDRS) is applied. With a NDRS DEA small DSOs are only compared with other small DSOs. To provide for flexibility in SFA estimations, normalized linear cost functions are assumed with

³⁵ See CONSENTEC (2006).

³⁶ See SUMICSID (2007).

³⁷ See Agrell et al. (2008a). Agrell and Bogetoft (2008a) provide for an English presentation summarizing the main features.

constant returns to scale and truncated normally distributed inefficiencies. Thus, in total four different efficiency benchmarkings are used

- DEA with company data (DEA I)
- DEA with standardized capital costs (DEA II)
- SFA with company data (SFA I)
- SFA with standardized capital costs (SFA II)

The high number of networks enables the BNetzA to use several output variables. The finally applied outputs are a result of several pre-tests of various model specifications (significance, explanatory power etc.). To map the two dimensions supply of end-users and supply of capacity eleven variables enter each efficiency benchmarking model

- number of connection points across all three considered voltage levels (high, medium, low)
- circuit of cables (high)
- circuit of lines (high)
- circuit of cables (medium)
- circuit of lines (medium)
- total network length (low)
- area supplied (low voltage level),
- annual peak load (high/medium)
- annual peak load (medium/low)
- number of transformer stations across all three considered voltage levels
- installed capacity of distributed generation across all three considered voltage levels.

The first seven outputs cover end-user supply, whereas the last four variables capture capacity-related aspects.

To determine the actual efficiency score (ES), a best off approach is applied with a minimum of 60%

$$ES = \max(DEA I, DEA II, SFA I, SFA II, 0.6)$$

The average efficiency score for electricity DSOs is 92.2% ranging from 75.5% to 100%. The correlation between the different approaches lies somewhere between 0.6

and 0.8 with the models based on standardized capital costs showing the highest correlations (see Agrell et al. 2008a: 72ff.).

3.4.3 Gas distribution

3.4.3.1 Regulatory regime

695 gas DSOs are existent in Germany of which 667 (ca. 95%) have less than 100,000 connected customers. The basic revenue cap formula is the same as for electricity DSOs:³⁸

$$R_t = C_{ex,t} + [C_{en,0} + (1 - d_t) \cdot C_{i,0}] \cdot (i_t - x_{gen,t}) \cdot ef_t$$

Compared to the regulatory framework for electricity DSOs, two main differences exist. First, in order to straighten out the burden for the regulator, the first period of gas DSOs is only four years followed by a second period of five years. Second, the threshold set in the incentive regulation ordinance to opt for a simplified procedure is 15,000 customers (instead of 30,000). The lower level has been mainly set in order to keep a sufficient number of DSOs within the efficiency benchmarking. There is also an on-going discussion on a quality regulation for gas DSOs. Although it is aimed at having established such regulation by the start of the second regulatory period (i.e. 2013), it is less likely to occur. Not only valid indicators are missing, but also it is regarded to be less needed. Gas is classified as a dangerous good meaning that gas network operators already have to meet several safety requirements making supply disruptions less likely.

3.4.3.2 Efficiency benchmarking

The current efficiency benchmarking design of gas DSOs is an outcome of the following steps

- Engineering based reference network modelling to identify possible cost drivers,³⁹
- A preliminary efficiency benchmarking study,⁴⁰
- Several rounds of stakeholder consultations and
- Final efficiency benchmarking study for gas.⁴¹

³⁸ For explanations of the various terms see section 3.4.2.1.

³⁹ See CONSENTEC (2006).

⁴⁰ See SUMICSID (2007).

⁴¹ See Agrell et al. (2008b). Agrell and Bogetoft (2008b) provide for an English presentation summarizing the main features.

Due to the sharing of responsibilities between the BNetzA and sub-national regulators and the option for small network operators with less than 15,000 connected customers, 187 DSOs have actually entered the current efficiency benchmarking. Just as the efficiency benchmarking of electricity DSOs, the German gas efficiency benchmarking consists of two methods, DEA and SFA. According to Appendix 3 of the incentive regulation ordinance and to protect small DSOs, a DEA with non-decreasing returns to scale (NDRS) is applied. With a NDRS DEA small DSOs are only compared with other small DSOs. To provide for flexibility in SFA estimations, normalized linear cost functions are assumed with constant returns to scale and truncated normally distributed inefficiencies. Thus, in total four different efficiency benchmarking models are used

- DEA with company data (DEA I)
- DEA with standardized capital costs (DEA II)
- SFA with company data (SFA I)
- SFA with standardized capital costs (SFA II)

The standardization of capital costs is the same as for electricity. The high number of networks enables the BNetzA to use several output variables. The finally applied outputs are a result of several pre-tests of various model specifications (significance, explanatory power etc.). To map the two dimensions supply of end-users and supply of capacity ten variables enter each efficiency benchmarking model

- number of exit points to end-users
- number of potential exit points to end-users
- area supplied
- pipeline length (≤ 5 bar)
- pipeline length (> 5 bar)
- annual peak load
- potential peak load
- volume of pipelines
- population 1995
- population 2006

The first five outputs cover end-user supply, whereas the last five variables capture capacity-related aspects. The number of potential exit points and the potential peak load are due to the fact, that large (populated) areas are still not connected to gas at all. Furthermore, even if parts of certain areas are connected, the percentage of connected customers is often below 10%. Therefore, the consideration of these two variables

intends to avoid the perverse incentive of gas DSOs not to extend their network to customers not yet connected to the gas grid. (see BNetzA 2006: 124 ff.).

To determine the actual efficiency score, a best off approach is applied with a minimum of 60%. The average efficiency score for gas DSOs is 87.3% ranging from 56.4% to 100%. Hence, for some gas DSOs the minimum efficiency score of 60% becomes applicable. The correlation between the different approaches lies somewhere between 0.6 and 0.9 with the models based on standardized capital costs showing the highest correlations (see Agrell et al. 2008b: 71ff.).

3.4.4 Appeal framework

In Germany, the BNetzA regulates postal services, telecommunications and railways and has taken up competence on electricity and gas only in July 2005. Competences are split between BNetzA and Regional Regulatory Authorities (FSR 2008). Legal action taken against BNetzA's decisions falls within the jurisdiction of a special cartel divisions of the civil courts; this is an exception from the general rule, according to which administrative courts decide over public law matters, with an aim to guarantee a uniform application and interpretation of the law. Since 2005 more than 900 court proceedings have been initiated. The competent court to deal with BNetzA's decisions is the Higher Regional Court of Düsseldorf. It examines both facts and legality and a special procedure applies, similar to administrative court proceedings. The court shall inquire into the facts *ex-officio*, and it proceeds to a strong review of the regulator's decision. An appeal on the legality of the decision is possible before the Federal Court of Justice, which is bound to the findings of the facts.

3.5 Norway

3.5.1 Overview of the energy market⁴²

Norway was one of the first countries in Europe to deregulate its electricity market, with the adoption of the Energy Act in 1991. The Norwegian power market has been formally open to competition since 1991, but real market access for all the end user groups was not established until 1995 through settlement based on the adjusted system load profile. The regulatory tasks are ensured by the Norwegian Water Resources and Energy Directorate (NVE). A regulatory office (department in NVE) was set up in 1990. The development of the Norwegian market has been followed by similar market opening in the other Nordic countries, and today we have an open and integrated electricity market in the Nordic region with a common Nordic power exchange. The Nordic market is also interconnected with the continental European market and Russia.

The Norwegian wholesale market is integrated in the Nordic wholesale market through price coupling on a common power exchange, Nord Pool Spot. Each entity operating in the electricity market and/or in the network business is required to hold a trading license. Status in June 2011 was that the NVE kept about 440 trading concessions under surveillance. There is one TSO in Norway, namely Statnett SF. The TSO has been legally unbundled in a separate company since 1992, and has to comply with the ordinary functional provisions.

3.5.2 Electricity distribution

3.5.2.1 Regulatory regime

The energy regulator in Norway is the Norwegian Water Resources and Energy Directorate (NVE) that regulates 155 network companies (NVE 2011). Norway was among the first European countries to introduce an incentive regulation based on efficiency benchmarking. Initially, DSOs operated under a rate of return (RoR) regime. In 1997, Norway switched to an incentive regulation based on the DEA technique (Førsund and Kittelsen 1998). The first regulatory period lasted from 1997 to 2001 followed by a second period from 2002 to 2006. The revenues were determined by a combination of average historical cost, efficiency requirements based on DEA, and annual updates of prices and new activities.⁴³ With 5-year regulation periods it has been argued that incentives for cost reductions are weakened when approaching a new

⁴² Further information is available at:

http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202011/NR_En/C11_NR_Norway-EN.pdf.

⁴³ The main features of the cap formula were quite similar to the current German regime, which is described in section 3.4.2.1.

regulation period, since actual costs are used as the starting point for the revenue caps for the next period (often called ‘the ratchet effect’). Therefore, Norway has changed its regulatory framework beginning with the third regulation period 2007 to 2012. From January 2007, the revenue cap (RC_t) regulation in the Norwegian electricity distribution sector is based on an yardstick formula with annual updates (Miguéis et al. 2011, NVE 2011)

$$RC_t = 0.4C_t + 0.6C_t^*$$

RC_t is the revenue cap in year t. C_t is the cost base for each network company, based on costs from year t-2 (lagged recognition of costs). The cost norm C_t^* is calculated based on relative efficiency scores found by DEA, which is explained in section 3.5.2.2. The efficiency benchmarking is also based on data from year t-2. With a weight on actual cost of only 40%, the ratchet effect is expected to be lower than in the previous regulation periods.

The cost base is calculated according to

$$C_t = (OM_{t-2} + CENS_{t-2}) \cdot \frac{CPI_t}{CPI_{t-2}} + PL_{t-2} \cdot P_t + DEP_{t-2} + RAB_{t-2} \cdot WACC_t$$

OM is the operation and maintenance cost and CENS is the company’s cost of energy not supplied. CENS is derived from estimated customer willingness to pay (WTP).⁴⁴ The cost of power losses is calculated by multiplying actual losses (PL) with the reference price of power (P). The price is a volume-weighted monthly area spot price from the electricity exchange Nord Pool Spot. The purpose of capturing the cost of power losses in such a way is twofold. First, the standardization of the price component over all DSOs implies that in the efficiency benchmarking companies are only compared by the quantity component, the actual power losses. Second, it incentivizes DSOs to purchase the corresponding amounts of electricity as cost efficient as possible. If network operators are able to buy the corresponding amounts at prices lower than the reference price, they can keep the profit. Otherwise, they face a loss. DEP is the depreciation, and RAB is the regulatory asset base (book value plus 1% working capital). The weighted cost of capital (WACC) is yearly adjusted by NVE. The corresponding values of WACC, the inflation based on the change of the consumer price index (CPI) and the reference power price P_t for 2009 and 2010 are shown in Table 5.

To arrive at the actually allowed revenue of a network operator, the property tax and network charges paid to other regulated grids are added to and cost of energy not supplied of the current year ($CENS_t$) are deducted from RC_t . The deduction is made, since CENS is not related to any compensations the DSO has to pay to customers.

⁴⁴ For the rationale to include outage costs as an element of the cost base entering the efficiency benchmarking see section 3.3.2.2.

Therefore, CENS does not involve any expenditures. While $CENS_{t-2}$ enters the cost base, the deduction uses information of the current year t . This design adds a quality of service element to the incentive regulation. The network operator is rewarded, if she improves on service quality compared to the year $t-2$ ($CENS_t < CENS_{t-2}$). Furthermore, to remove the two-year time lag on investments, companies can add the calculated revenue from investments already in the year the investment is made.

Table 5: Basic parameters of the Norwegian regulatory framework

	2009	2010
$WACC_t$	6.19%	5.62%
CPI_t/CPI_{t-2}	1.0599	1.0463
P_t [NOK/MWh]	318	436

Source: NVE (2011: 26).

The revenue compliance is subject to regulatory control. For each DSO, NVE sets a yearly balance on excess/deficit revenues, which are calculated as the difference between actual revenues in year t and the allowed revenue in year t . The difference is cancelled out over time through tariff adjustments. A positive balance has to be reimbursed to customers, while deficits may be recovered during the next period due to an increase in tariffs.

3.5.2.2 Efficiency benchmarking

The cost norm C_t^* of each network operator is a result of a DEA benchmarking analysis. Norway is the only country where the regulator has systematically examined the effects of environmental factors on the performance of the quality of service and reflected these in the efficiency benchmarking models. The regulator has analysed a large number of geographic and weather variables and has applied SFA technique to construct composite indices from few selected variables (cf. e.g. Bjørndal et al. 2008, 2009). The current efficiency benchmarking utilizes measures of snow, forest, and coastal climate as output variables in the DEA model. Hence, the model assumes that these affect the firms' production function (rather than efficiency).

The model used by NVE is a super-efficiency variant, such that the scores may be higher than 100% (Miguéis et al. 2011). This enables a company that performs better than others and improves over time to have a cost norm higher than the actual cost. The efficiency estimates found from DEA analysis are calibrated such that the cost weighted average efficiency score is 100%. This implies that a representative company, with an average efficiency score, is allowed to earn the normal rate of return, and efficient companies can earn more than the normal WACC. This design intends to

promote efficiency improvements over time and the attractiveness of the industry to investors.

For DSOs, the efficiency scores for year *t* are estimates applying an input-oriented model with constant returns to scale (CRS) and data from year *t-2*. The input specified is total cost, which includes operational costs, capital costs and quality costs (measured by the value of lost load). The last cost element is associated to the cost of interruptions of electricity supply and consequently measures the quality of service. It corresponds to CENS in the revenue cap formula.

Table 6: Output variables of the Norwegian DEA model

<i>Variable</i>	<i>Unit of measurement</i>
Energy delivered	MWh
Customers (except outages)	No. of customers
Cottage customers	No. of customers
High voltage lines	Kilometres
Network stations (transformers)	No. of stations
Interface	Cost weighted sum of equipment in the interface between the distribution network and the transmission network
Forest	Proportion (0-100) of area with high-growth forest × HV-lines through air (kilometres)
Snow	Average precipitation as snow (mm) × HV-lines through air (kilometres)
Coast/wind	[Average wind speed (m/s) / average distance to coast (meters)] × HV-lines through air (kilometres)

Source: Bjørndal et al. (2009: 6).

The selection of output variables was one of the most challenging issues when the new regulation model was developed prior to its introduction in 2007. The regulator formulated three criteria that should be met if an output variable was to be included in the model. Firstly, the variable should have a solid “theoretical and practical” foundation. Secondly, it should have a statistically significant effect on company costs in SFA model test, as well as on the DEA efficiency in OLS regression tests. Thirdly, the variable should also be statistically significant in the so-called “Banker test”, such that the efficiency estimates obtained using models with and without the considered variable had to be significantly different. Hence, although a large number of candidate variables were considered initially, the final set of variables shown in Table 6 was determined mainly based on statistical tests. For example, a variable representing low voltage lines was rejected based on the Banker test, whereas the high voltage line variable passed the test and is included in the model.

The output variables energy delivered and the number of customers connected measure direct outputs from the production activity of the distribution companies. Customers were separated in cottage customers and regular customers, since the former usually consume less energy than ordinary customers. The model also contains output variables that represent structural and environmental conditions that may influence the cost of the companies. Three of the variables (HV-lines, network stations, and interface) are in fact input variables. Their role in the DEA model is to represent demographical and topological conditions, as well as transmission functions, that influence the costs of a particular company, and for which a better representation has not been found. The last three variables (forest, snow, coast/wind) describe environmental conditions that may influence the cost of the companies, and are the only variables that are not based on data reported by the companies.

Based on decisions made in 2009, NVE decided to amend the model for the distribution system operators (Growitsch et al. 2010). To control for effects which influence the efficiency level rather than the production technology, cost norms are calculated through a two-step analysis. In the first step, DEA-scores are calculated. In the second step, these DEA-scores are corrected through regression analysis. The second-stage regression aims at estimating the efficiency effect of the number of connections to regional networks, installed capacity for small hydro power generators connected to the grid, and the number of supplied remote islands.⁴⁵

3.5.3 Appeal framework

In Norway the energy regulator is the Norwegian Water Resources and Energy Directorate (NVE). Appeals shall be first sent through NVE for its own review, then to the Ministry as the immediate superior administrative agency (FSR 2008). The appeal instance is competent to make a full review. The appeal process is free of charge and a party may be awarded to pay only the necessary costs to get the decision altered. The review by the judiciary is done by ordinary courts and is based on errors of facts, procedure and law; since the plaintiff runs the risk of paying the costs of the case, it is not common in Norway to use the ordinary courts to review decisions. Complaints against the regulator's decisions may also be lodged before the Ombudsman, which is competent to investigate and evaluate injustice, maladministration and human rights violations by the public authorities; the Ombudsman may pass an opinion, but not take legally binding decisions, yet its opinions are widely respected and public agencies usually comply with them.

⁴⁵ More detailed information on the second stage regression was not available. For an introduction of second stage regressions in the DEA context see Ray (1991). Barnum and Gleason (2008) discuss important bias problems that may arise with this approach. For an application of this method with regard to Norwegian electricity DSOs see Bjørndal et al. (2009). The authors compare a two-stage DEA model with a DEA using weight restrictions.

3.6 Spain

3.6.1 Overview of the energy market⁴⁶

Electricity and gas markets have been fully open to competition since 2003. A large percentage of customers (more so in electricity than in gas) chooses to remain with the incumbent utilities under a regulated tariff, which is below liberalized market prices. The incumbents are financially compensated for the deficit caused by the low level of tariffs. The impact of the tariff market for gas is far less negative than for electricity with the deregulated market. The wholesale electricity market is integrated with that of Portugal into an Iberian regional market (MIBEL).

The incumbent generators and distributors dominate the Spanish generation and supply markets. The three main operators cover around 60% of the energy share. Endesa SA and Iberdrola SA are the two main national players. Spain has got one TSO which is ownership-unbundled and owned 20% by the state. Though incumbents are still major suppliers, a number of independent suppliers have entered the market, mainly as niche players.

Gas Natural (GN) is the incumbent vertically integrated former monopoly in the gas sector (now with activities also in the electricity sector). The TSO is fully ownership unbundled while, in distribution, activities have not been fully functionally unbundled within GN. In the retail market, competition was enabled through a gas release program in 2001, which made 25% of imported gas available to traders in the free market.

3.6.2 Electricity distribution

3.6.2.1 Regulatory regime

The Spanish electricity distribution sector consists of five large DSOs covering 97.5% of electricity supply and around 320 smaller network operators representing the remaining 2.5% (Fernandez 2008). DSOs are controlled by the Spanish energy regulator, Comisión Nacional de Energía (CNE). With the Royal Decree 222/2008 Spain has established a new regulatory framework for electricity DSOs (Candela 2009). A revenue cap regulation has been implemented. The first regulatory period of 4 years started in 2009. The allowed revenue in a certain year R_t is

⁴⁶ Further information is available at:
<http://www.cne.es> (the Spanish Energy Regulator),
http://ec.europa.eu/energy/electricity/benchmarking/index_en.htm (Benchmarking Reports),
http://www.ceer-eu.org/portal/page/portal/EREG_HOME/EREG_DOCS/NATIONAL_REPORTS/2006 (National Reports),
http://www.iern.net/portal/page/portal/IERN_HOME/IERN_ARCHIV/Country_Factsheets/Country%20Factsheet?pld=3062055&pPath1=Europe&pPath2=Spain.

$$R_t = R_0 \cdot (1 + A_t) + Y_{t-1} + Q_{t-1} + L_{t-1}$$

The starting values R_0 , which incorporate operating (e.g. maintenance, staff, customer services) and capital costs (depreciation and WACC-based rate of return), are updated with the index $A_t = 0.2 \cdot (i_{CPI} - x) + 0.8 \cdot (i_{IPI} - y)$. The inflation rates for consumer prices (i_{CPI}) and for industrial prices (i_{IPI}) are weighted according to the capital intensity of the sector. The Spanish Ministry of Economics set the two efficiency factors to 0.8% p.a. for x and 0.4% p.a. for y without consulting CNE (Candela 2011). Y_t refers to a revenue adder due to an increase in demand and aims at covering additional investments during the regulatory period.⁴⁷ The other two terms entering the cap formula intend to set incentives with regard to the reduction of distribution losses (L) and to the improvement of supply quality (Q). Both are designed as a bonus/malus regime, which is based on the DSO's performance relative to a predetermined index. If the DSO performs better than the set index, it receives a bonus. Otherwise, the allowed revenues are reduced accordingly. While L is limited to +/- 1% of the overall cap, Q is limited to +/- 3%. The incentive to reduce losses is defined as

$$L_{t-1} = 0.8 \cdot p_{el} (l_{ind} - l_{t-1}) \cdot (e_{imp} + e_{gen})$$

with p_{el} as the average electricity price and the actual losses of the previous year l_{t-1}

calculated as the ratio of $l_{t-1} = \frac{(e_{imp} + e_{gen}) - e_{sup}}{(e_{imp} + e_{gen})}$;

- e_{imp} : electricity obtained from the upstream network;
- e_{gen} : electricity generated by facilities directly connected to the distribution network;
- e_{sup} : electricity supplied to customers.

The target ratio of electricity losses, l_{ind} , is agreed between the Ministry and the DSO and constant over the regulatory period. The difference between the two loss ratios is valued at the average electricity price of the considered year.

The incentive to quality improvements, Q_{t-1} , is based on indicators measuring the duration of interruptions (SAIDI) and the frequency (SAIFI):

$$Q_{t-1} = c_{SAIDI} \cdot \sum_z [P_z \cdot \Delta SAIDI_z] + c_{SAIFI} \cdot \sum_z [C_z \cdot \Delta SAIFI_z]$$

- c_{SAIDI} : incentive value of 100 c€/kWh;
- c_{SAIFI} : incentive value of 150 c€ per customer and interruption;
- P_z : installed power generation in zone z ;
- C_z : number of customers in zone z ;

⁴⁷ Information on the specific design of Y has not been available.

- Δ_z : difference between reference level of the indicator and the actual observation in year t-1 in zone z.

The incentive scheme divides the whole area served by a DSO into different zones z. Four main categories are distinguished:

- Urban: group of municipalities of a province with more than 20,000 customers (including the capitals of the provinces);
- Semi-urban: group of municipalities of a province with more than 2,000 and less than 20,000 customers;
- Rural concentrated: group of municipalities of a province with more than 200 and less than 2,000 customers;
- Rural dispersed: group of municipalities of a province with less than 200 customers and supply points located outside industrial or residential sites.

For these four categories, different reference levels are set (see Table 7). The higher the population density, the lower the corresponding reference level.

Table 7: Reference levels for quality of supply

	SAIDI [hours]	SAIFI [number]
Urban	1.5	3
Semi-urban	3.5	5
Rural concentrated	6	8
Rural dispersed	9	12

Source: Fernandez (2008: 40).

In order to determine the starting values for the revenue cap, R_0 , CNE has developed a toolbox, called EVEREST (Economic Validation Electrical Reporting Efficient System Tool). The toolbox consists of various sub-tools, e.g.

- Homogenous codification,
- Validation tool for information provided by DSOs,
- Two different network reference models,⁴⁸
- A regulatory accounting system,
- Detailed inventory of existing distribution assets,
- Geographical representation tool (GIS).

For the first regulatory period, the reference modelling was only applied to the five large DSOs. For the vast majority other sources like inventories and financial statements

⁴⁸ See section 3.6.2.2.

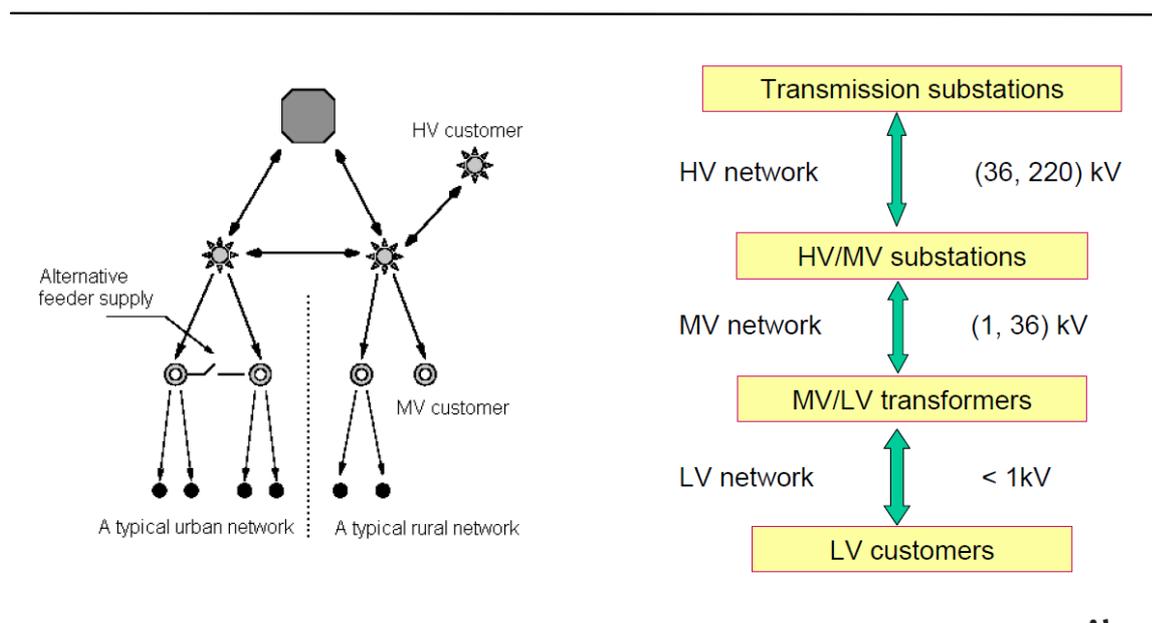
were used. However, the actual determination of R_0 resulted from bilateral agreements between DSOs and the Ministry of Economics. Agreements were only partly based on the preceding evaluations of CNE (Candela 2011).⁴⁹

According to CNE, it is planned to apply the network reference model to all DSOs for the second regulatory period starting 2013. Currently discussed between the regulator and stakeholders are also the following issues (Mateo et al. 2011):

- adjustments of the incentive regime for quality of service,
- integration of distributed electricity generation into the reference model due to the increasing amount of renewable energy fed into the grid
- consideration of economies of scale.

3.6.2.2 Efficiency benchmarking

Figure 2: Scope of the network reference model



Source: Fernandez (2008: 27).

The basic network reference model used by CNE has become known as the PECO model, named after its main developer, Jesús Pascual **Peco** González (2004). In order to obtain an adequate benchmark of actual networks, the model designs large scale electricity distribution networks optimally, considering all technical features imposed to

⁴⁹ Specific information on these agreements was not available.

actual distribution networks. The different voltage levels taken into account are illustrated in Figure 2. The objective function is:

$$\min(\text{total cost}) = f(\text{investment, O\&M, quality of service, network losses})$$

CNE considers two different ways of designing the network:

- Greenfield (from scratch): to optimally design a whole network that connects customers of electricity to transmission substations without taking into account the actual network, but considering the same technical constraints and planning principles.
- Scorched-node (expansion planning): to optimally design distribution network expansions in order to supply both a horizontal and a vertical demand increase, given the actual network and considering the same technical constraints and planning principles.

Input data can be grouped into three categories:

(1) Customers and transmission substations geo-referenced data

This database is the basic input to the network reference model. Customer data include e.g.: GPS coordinates, contracted power and annual energy consumption.

(2) Distribution service areas modeling parameters

The objective of this set of parameters is to achieve an accurate modeling of the distribution service areas. The main parameters that belong to this category are:

- Parameters associated with the selection of aerial lines or underground cables within a certain distribution area.
- Simultaneity coefficients to obtain system peak load from customers' contracted power.
- Load and loss factors used to compute energy and network losses in the different voltage levels.
- Historical network voltage levels.
- The price of energy losses.

CNE regards most of these parameters as being out of control of DSOs. Therefore, these parameters are not part of the objective function. This set of parameters is fitted to capture the characteristics of a certain area most accurately. In particular, model results and the actual network should match with regard to the percentage of LV, MV and HV aerial lines/underground cables, the peak load and annual energy supplied.

(3) Optimization and efficiency promoting parameters

These parameters set the basis for an optimal network design from the regulator's viewpoint considering current and future demand. Lumpiness of network investments (economies of scale), network losses and the quality of service are accounted for. The main parameters are:

- The rate of return used to compute the present value of network losses and O&M costs.
- The reserve factors used to size assets are a key issue in promoting a long-term stable investment signal to distribution utilities.
- The quality of service indices that should be satisfied by both the actual and the reference network.
- The standardized equipment database (lines, cables, distribution transformers, distribution substations, protective devices etc.) used to design the network.

These parameters determine the key features of the efficient network required to supply an area supplied by the considered DSO. Therefore, these parameters are set by the regulator in order to promote an efficient performance both in the short and long term.

The PECO model is a planning tool with the following main features:

- The model considers GPS coordinates of customers and transmission substations to build the whole distribution network, that is: (i) MV/LV transformers, (ii) HV/MV substations, (iii) and LV, MV and HV networks.
- The model automatically determines the corresponding street maps from the GPS coordinates.
- Further constraints, such as orography raster maps and restrictions to build the network, can be accounted for in order to modify locations of specific network elements.
- The optimization of both urban networks (constrained by the street map) and rural networks (considering orography and other building restrictions) are performed simultaneously.
- The network is determined by minimizing total costs (i.e. investment cost, operation & maintenance cost, losses subject to capacity, voltage and reliability constraints), and taking into account present demand and an estimation of its future growth.
- The network reliability assessment is computed simulating real process after a network failure has taken place: (i) fault detection, (ii) fault location, (iii) fault clearance, and (iv) service restoration.

- The reliability assessment is computed using the parameter “cost of energy not supplied”, which can be different for each customer. This parameter is crucial regarding model results (in particular with regard to size and number of HV/MV substations and the MV network). The model allows for quantifying the relationship between network investment and network reliability.
- Further results are power flows, the number and duration of interruptions, the location of network devices and the overall network topology.

3.6.3 Appeal framework

In Spain, regulatory decisions are taken by CNE whose independence with respect to Government has been questioned.⁵⁰ In general, all the regulatory decisions may be appealed before the Ministry of Industry and Energy, and this remedy is obligatory in order to appeal to judiciary authorities. However, the resolutions of CNE that decide disputes on the economic and technical management of the system are exempt from this remedy: they end the administrative procedure and open the door to the judicial review. The competent jurisdiction is the Contentious-Administrative Division of the National High Court (whose decisions may only be appealed before the Constitutional Court for violation of fundamental rights). The magistrates are specialists in administrative law, and although they do not need a specialization in the regulation sector for their appointment, they are usually competent in this field because of their experience and previous dedication to the matter. The scope of the judicial action concerns formal defects in the administrative procedure, substantive rights and the proportionality of the act.

⁵⁰ See e.g. Larsen et al. (2007), FSR (2008) and Correlje et al. (2011).

3.7 Sweden

3.7.1 Overview of the energy market⁵¹

The Swedish electricity market was deregulated in 1996. The Swedish Energy Markets Inspectorate (EI) is the regulatory authority for the electricity, natural gas and district-heating markets. The wholesale market is considered competitive, as Swedish power generation is part of the regional Nordic market (which also includes Denmark, Finland and Norway). The retail market exhibits higher than average switching rates. Prices for electricity are below EU averages, whereas the opposite is true for gas prices which are significantly above EU averages.

The production of electricity in Sweden is dominated by a small number of companies. However, due to the presence of the Nordic regional market in which Sweden participates, the wholesale power market is more competitive. The TSO is unbundled in terms of ownership, whereas the distribution companies are required to unbundle in legal terms.

There is no natural gas extraction in Sweden, which imports all the natural gas consumed there from Denmark via a pipeline that links these two countries. There are also pipelines from Denmark to the rest of Europe, which means that Sweden is linked to the continental system. In 2010, 30% of this natural gas was consumed by industry and 56% by co-generation plants, with housing accounting for around 5% and other commercial operations for the remaining consumption. E.ON Sverige and Dong Energy are the two companies that sell natural gas on the Swedish wholesale market. Dong Energy is 73% owned by the Danish state, while E.ON Sverige is owned by E.ON AG, (privately owned energy company, Germany). There are five distribution companies.

3.7.2 Electricity distribution

3.7.2.1 Regulatory regime

The Energy Market Inspectorate (EI) is the Swedish regulator for energy markets and responsible for monitoring the energy legislation, designing regulatory rules, and deciding on concessions for distribution networks. Furthermore, EI analyses market developments and, if necessary, proposes amendments to existing regulations. A

51 Further information is available at:
<http://www.stem.se/> (the Swedish Energy Regulator),
http://ec.europa.eu/energy/electricity/benchmarking/index_en.htm (Benchmarking Reports),
http://www.ceer-eu.org/portal/page/portal/ERGEG_HOME/ERGEG_DOCS/NATIONAL_REPORTS/2006 (National Reports),
http://www.iern.net/portal/page/portal/IERN_HOME/IERN_ARCHIV/Country_Factsheets/Country%20Factsheet?pld=3070043&pPath1=Europe&pPath2=Sweden.

pivotal task of EI is the review of the electricity network charges. Sweden has around 170 electricity distribution network operators (see EI 2011a: 24). Between 2003 and 2007, Sweden applied an engineering-based reference network model, the so-called Network Performance Assessment Model (NPAM), within an ex post regulation framework for electricity DSOs to evaluate network tariffs.⁵² The tariff regulation using NPAM was strongly criticized by stakeholders followed by lawsuits. The main arguments against NPAM are that it is not accounting for historical circumstances (such as investments in areas with a decreasing need for electricity)⁵³ and not sufficiently robust to fulfil the criteria of objectiveness. Furthermore, NPAM does not support climate change related issues such as incentives for low network losses which have become increasingly important when adopting the regulation of distribution network tariffs to a smart grid perspective (cf. e.g. Jamasb and Pollitt 2007 and Wallnerström and Bertling 2010). The legal actions would have taken several years to settle the dispute between the regulator and industry. In late 2008, the parties reached an agreement on the regulatory treatment for the period 2003 to 2007 and decided to change the regulatory framework. In January 2009, the regulator formally abandoned NPAM.

After the NPAM had been cancelled, EI has put a lot of effort into the development of a new regulatory framework which starts 2012. It is designed as an incentive regulation based on revenue caps that are determined ex ante. The duration of the regulatory period is four years. Thus, the first period lasts from 2012 until 2015 (see EI 2011b and Ek 2011).

Figure 3 illustrates how the revenue cap is determined. The costs entering the allowed revenue are somehow disconnected from companies' historical accounting values. The cost of capital are based on a calculation of the asset base applying a pre-determined rate of return and pre-determined asset life times for depreciation. Based on two studies of financial consultancies, EI has set the weighted average cost of capital to 5.2% for the first period. A re-evaluation will be done for the second period starting 2016.

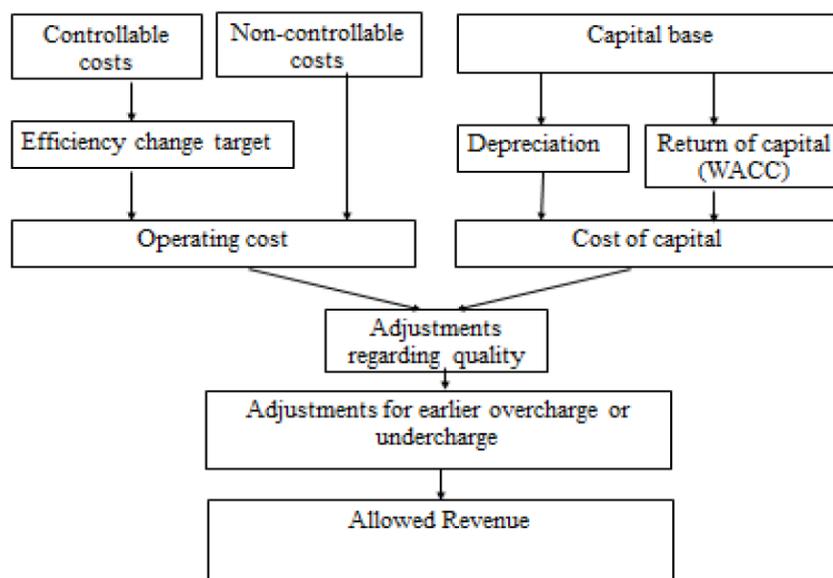
Regarding the valuation of the network asset base, the main principle is to apply real annuities based on replacement values set by the regulator. EI has decided on approximately 650 standard replacement values for network components. E.g., different standard or norm values have been set for cable investments depending on the soil characteristics and the urbanization. During the regulatory period, the value of the asset base is adjusted to inflation using a price index covering the development of production costs of buildings. The index is provided by the Swedish Statistical Office. This general valuation principle is supplemented by three other methods when explicit replacement values are not known. The three approaches are:

⁵² As the new regime contains no efficiency benchmarking, the main features of the abandoned NPAM are presented in section 3.7.2.2.

⁵³ This point is closely related to the argument of stranded investments that is often raised by industry with regard to energy regulation.

- Valuation according to the value at the time of investment,
- Valuation according to the book value,
- Some other methods.

Figure 3: Elements of the new ex ante regulation



Source: Ek (2011).

If standard values of certain network assets are not existent, the three listed methods are of descending priority. Other assets apart from network assets like office buildings, vehicles and computers are converted into operating costs. On the other hand, leased network assets are regarded as a part of the asset base and thus converted into capital costs.

The operating costs distinguish between controllable and non-controllable (exogenous to the core activities of the DSO) cost categories. Among the former are e.g. staff and cost for services bought. Furthermore, the converted costs of other assets are also regarded as being controllable. Examples for non-controllable costs are fees paid for the usage of the upstream network and grid losses. The starting values for the OPEX are based on audited accounting data provided by the DSO. The values correspond to the average of the period 2006 to 2009. Values are then inflated to the price level of 2010.

An efficiency target of 1% p.a. in real terms is only applied to the controllable operating costs. For the first period, there is no differentiation across companies. Hence, no benchmarking of DSOs has been carried out to set individual efficiency targets. The determination of the value is based on a review of international experiences and some preliminary productivity analysis of the Swedish electricity sector. An analysis of the productivity development for the years 2001-2008 in the DSO sector in Sweden was done by EI with application of regression analysis, SFA and DEA. The mean development of productivity was estimated to 2 % p.a. The model used for the estimation of productivity development consisted of controllable operative cost as input and three outputs (number of customers, length of lines and cables and installed capacity of transformers). There was no need to incorporate other environmental variables as the focus was to estimate the development of productivity and not to compare companies (EI 2010).

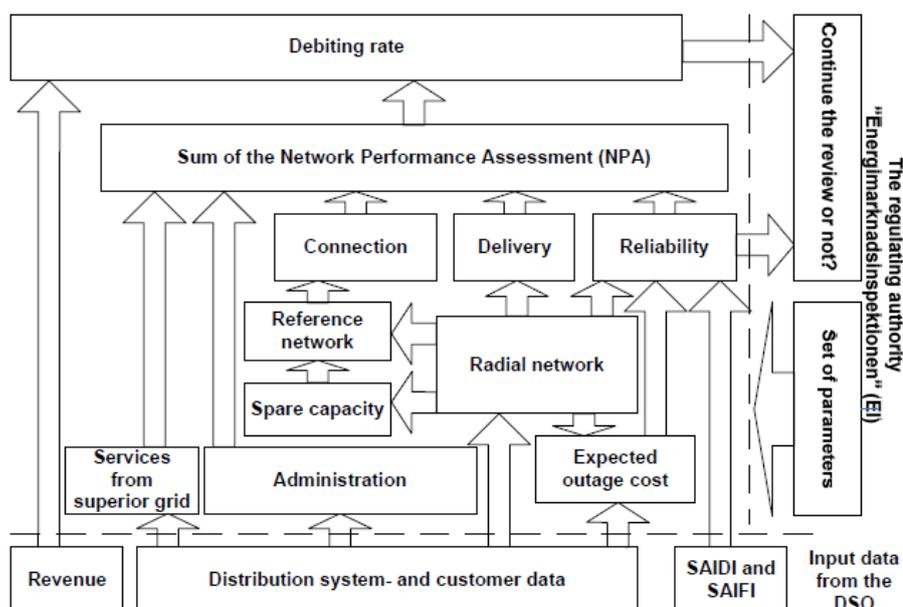
The revenue cap is accompanied by a quality regulation consisting of a bonus/malus regime. A bonus is assigned if supply reliability is above a certain standard level, a malus is deduced from the allowed revenues if actual system reliability falls below the standard level. Unplanned outages between 3 minutes and 12 hours and planned outages longer than 3 minutes are used as a basis for quality control. The reason for this restriction is that network operators are already obliged to pay compensation for outages that are longer than 12 hours. For the first period, the standard level is determined for each DSO individually using the two indicators SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index). These indicators of supply security are well established, and statistics for several years do exist. The standard level for a certain DSO is calculated as the average of these indicators which the DSO reported for the period 2006 to 2009. To determine the costs that customers attach to system outages, EI has used a cost assessment of the Swedish industry association for electricity DSOs. As the study was carried out in 1994, these interruption costs for customers have been simply updated by inflating the values with the consumer price index (CPI). To protect smaller DSOs in case of extreme weather events, the bonus and malus is limited to 3% of company's annual allowed revenues.

3.7.2.2 Efficiency benchmarking

The NPAM was an assessment of the customer values of an electricity distribution system. The basic idea was that DSOs were only be allowed to collect revenues that correspond to these customer values. Figure 4 provides for an overview of NPAM. Three types of input data were collected from DSOs, actual revenues, network and customer data and information on system outages. Concerning customer data, information on the geographic co-ordinates of all customers for each network company was obtained. Furthermore, information was collected on customers with regard to numbers, energy, and power. The allowed revenue consisted of five different cost

factors, i.e. connection, delivery, reliability, administration and services from upstream grids. The first three categories, in turn, depended on the reference network including spare capacity and a radial network.

Figure 4: Overview of NPAM



Source: Wallnerström and Bertling (2010: 2).

The model created a reference network based on technical and legal requirements and with high service quality standards. The reference network was designed as if a new network would have been built instantaneously. The model was developed using a stylized optimum design and standard assets. The main algorithm consisted of four steps

1. The customer outage costs were calculated from data reported by the DSOs.
2. A virtual radial network was created based on input data. A sequential Monte Carlo simulation was used to simulate the expected behaviour of the system. A Weibull distribution was applied to model failure occurrences for certain network components. Three states of network elements were distinguished: operation, service and failure. The simulations included the effect of component failures with regard to planned and stochastic events. The resulting outage costs were evaluated for the radial network.
3. An incremental cost approach was used to analyse different alternatives for component redundancy (e.g. transformers). Monte Carlo simulations were used

to evaluate the resulting outage costs for different investment alternative leading to a list of possible redundancy solutions. Out of this list, the most profitable alternative was selected, i.e. where the gain in outage costs was higher than the required annual costs for investments in component redundancy.

4. Finally, Monte Carlo simulations for system failures were carried out based on the redundant reference network determined in step 3. The simulations aimed at assessing the behaviour of the redundant reference network and identifying further redundancy opportunities.

According to Wallnerström and Bertling (2010: 7), the most crucial simplifying assumptions were the following:

- Only single failures were considered, i.e. simultaneous failures of different components are neglected.
- No load flow analysis was carried out for dimensioning the spare capacity of feeders. This implied that the resulting reference network could have feeders that lacked capacity to deliver the energy requested by customers and modelled by NPAM.

Using the reference network NPAM derived an installation register for:

- Meters of line per bleeding point
- A density measure to every meter of line
- Number of transformer stations
- Capacity for every transformer station
- A density measure for every transformer

The model calculated the investment cost of a reference firm based on standard costs of equipment from the Swedish Electricity Building Rationalisation (EBR) catalogue. Costs of building and operating an efficient network today and related costs were derived from a number of cost functions for:

- Capital expenditures (real cost of capital) - compensation for depreciation, equity, debt (risk free and risk premium)
- Cost of operation and maintenance
- Network administration costs
- Cost of network losses
- Financial costs
- Return on capital

Deductions from revenues were made for quality of service using supply interruptions data of actual companies and customer willingness-to-pay (WTP) values. Costs of the reference network were then compared against those of the actual networks to obtain a “debiting rate” (as ratio of cost of real firms over the reference firm) as performance measure of the real network. The efficiency benchmarking exercise was to take place every year ex-post and relative to the previous year. Firms with debiting rates exceeding unity by a certain margin could then have been subject to detail investigation and efficiency requirements by the regulator. For the first year, the threshold used by the regulator was 1.3, and 1.2 thereafter (Wallnerström and Bertling 2010: 3).

3.7.3 Appeal framework

In Sweden network operators are under the supervision of the Energy Market Inspectorate (NordREG 2007). Distribution system operators may issue technical terms on connections and other system services which are approved ex ante by EI. In general, EI may settle disputes and issue decisions involving DSOs on own initiative, on the basis of a notification or on the basis of complaints. Complaints over connection fees, tariffs and other terms and conditions can be brought forward to EI for decision. EI's decisions can be appealed to the Administrative Court. If granted, a judgment of the Administrative Court may be appealed to the Administrative Appeal Court. Finally, a decision of the Administrative Appeal Court may be appealed to the Supreme Administrative Court. Thus, the Swedish appeal framework has three main levels. According to Fredriksson (2009), one of the major concerns with the appeal framework in Sweden is the long duration until final decision is made. Sometimes, this can take up to 12 years.

4 Transmission system operators

In most European countries, there is only one transmission system operator (TSO) both in the electricity and gas sector.⁵⁴ Therefore, the scope for national efficiency benchmarking of TSOs is very limited.⁵⁵ With regard to gas, Germany is the only EU country applying national efficiency benchmarking for regulatory purposes.⁵⁶ A comparable high number of TSOs (actually a number of eight) enables the regulator to conduct a national efficiency benchmarking. Although only four German electricity TSOs exist, the BNetzA has decided to use efficiency benchmarking also for electricity transmission companies. In the following, we present the two German approaches enriched by two studies commissioned by the Council of European Energy Regulators (CEER) on international TSO efficiency benchmarking.

4.1 Electricity

4.1.1 CEER

To overcome the problem of an insufficient number of TSOs for benchmarking purposes, the Council of European Energy Regulators (CEER) under participation of 19 national regulatory authorities commissioned a study on international efficiency benchmarking of TSOs in the electricity sector.⁵⁷

In this study, data of 22 European TSOs is used to test different benchmarking methods. The authors therefore describe how the cost data of the different TSOs is standardized, conduct a cost-driver-analysis and illustrate different benchmarking techniques in general. They then try to find the optimal benchmarking model for the given data. This is done by defining some selection principles for choosing variables for efficiency analysis (robustness, verifiability, unambiguousness, output (correlated), minimal structural impact, feasibility).

As a result the best model specification is to use TOTEX as cost and a normalized grid TOTEX proxy, density and renewable power including hydro as cost drivers. Moreover, the best estimation technique given the limited data is to use the DEA-NDRS approach.

The SFA is assessed to be less eligible. The convergence of the SFA models is very unstable. This reflects that too much variation is left unexplained in data to estimate a parametric SFA model, i.e. it is largely impossible to separate noise and inefficiency using maximum likelihood estimation.

⁵⁴ European Commission (2011b).

⁵⁵ One example for applying individual efficiency targets in the case of only one TSO is Finland. For further information see Energiamarkkinavirasto (without date).

⁵⁶ KEMA (2009).

⁵⁷ Agrell and Bogetoft (2009).

It also turned out that international comparisons involves severe problems because the transmission network operations of various countries differ from one another in size and structure. Furthermore, there are significant differences between various countries regarding the definition of activities included in transmission network operations and the principles used when recording financial statement data. International efficiency comparisons in transmission network operations have been carried out, but their aspect and purpose has, by and large, been other than that related to regulation.

4.1.2 Germany

German electricity TSOs operate under a revenue cap regulation since 2009. The corresponding approach is similar to the one for electricity DSOs, which is explained in section 3.4.2.1. The main difference is that the cost share, which is regarded as being exogenous to the network operator's core activities, $C_{ex,t}$, is much higher than for DSOs.

This is mainly due to two reasons:

- TSOs are obliged by law to take responsibility for the functioning of the overall system, which means that they have to implement adequate measures and have to take corresponding actions in order to provide for a stable electricity supply (power frequency and outages). Therefore, costs associated with these measures and actions are seen as being exogenous.
- Investment budgets play a much greater role at the TSO level. Investment cost covered by the budget are excluded from efficiency requirements. A large part of TSOs' investment activities are currently concerned with the connection of off-shore wind parks. As TSOs are obliged by the Renewable Energy Sources Act to provide for these grid connections, associated cost are excluded from incentive regulation.

With regard to efficiency benchmarking, Art. 22 (1,2) of the incentive regulation ordinance takes into account the relatively low number of TSOs and enables the regulator to include methods additional to ones at the DSO level (SFA and DEA) to evaluate network operator's performance, in particular:

- Consideration of transmission system operators of other EU Member States, and
- Engineering-based reference network modeling.

The precondition to apply these measures is that comparability is assured with regard to structural, technical, legal and economic aspects. The BNetzA has included the following information to benchmark TSOs' efficiency:⁵⁸

⁵⁸ Herrmann (2009).

- Results of the CEER study on the international efficiency benchmarking of European electricity TSOs (see section 4.1.1), and
- Performance of an engineering-based modeling for each of the four considered networks.

Afterwards, the outcomes of both measures were discussed between the regulator and the four TSOs. An agreement was reached on the actual efficiency scores, which are listed in Table 8.

Table 8: Efficiency scores of German electricity TSOs

Company	Efficiency score
E.ON	100 %
Vattenfall	99.60 %
EnBW	100 %
RWE	90 %

Source: BNetzA (2009).

4.2 Gas

4.2.1 CEER

On behalf of CEER, Jamasb et al. (2008) conducted a study on efficiency benchmarking of European Gas TSOs. In the final report, the authors describe different benchmarking techniques (DEA, SFA, COLS) in general, indicating advantages and disadvantages of these approaches. They discuss potential obstacles that should be taken into account when choosing the “right” benchmarking technique. These are:

- Focussing on economic welfare (no engineering approach),
- asymmetric information between regulator and firm,
- insufficient number of comparable European observations to produce robust efficiency scores,
- comparability (of data), and
- arriving at relevant and consistent efficiency scores.

Within the actual efficiency benchmarking, the authors use also data from the US, thus trying to mitigate the problem of the number of observations. They apply three different benchmarking techniques (DEA, SFA, COLS) to the data.

As a result, the authors give the following recommendations for the application of efficiency benchmarking to gas transmission in Europe:

For data and comparability:

- robust benchmarking results cannot be obtained without long-term commitment to build appropriate databases,
- this implies agreeing on functional boundaries for transmission operators and standardizing all data,
- in case of insufficient European data, benchmarking with US companies is a viable strategy, surely direct communication with the US regulator FERC can reduce issues of comparability,
- but even without high comparability between US and European firms, it is possible to produce a relative ranking of European firms,
- under incentive regulation few high quality strategic variables may be sufficient to obtain robust X-factors.

For the variables:

- high correlations among cost-drivers make it difficult to include several of them in standard cost functions for the purpose of econometric analysis,
- on the other hand, this means that some variables can be feasible substitutes for others,
- measures of capacity and network length might be sufficient to capture the cost function of gas transmission operators, and
- revenue is highly correlated with the cost measures and produces very similar efficiency scores across firms.

For the benchmarking techniques:

- gas transmission seems to be a business that can easily be modelled and measured econometrically (using OLS). With few strategic output variables the authors were able to produce rather consistent results;
- Stochastic Frontier Analysis, a theoretically very appealing technique, may not be sufficiently robust to be readily employed without fine-tuning the specific dataset at hand, and
- in a regulated industry where rate-payers fund utilities' activities, revenue should be an important regulatory focus area next to cost measures.

4.2.2 Germany

The German regulator *Bundesnetzagentur (BNetzA)* conducted an efficiency comparison of eight national gas TSOs in 2008. These TSOs are subject to a revenue-cap regulation. The cap formula is the same as for German DSOs (see section 3.4.2.1).

The cost element ($C_{t,0}$) represents the individual inefficiency of a TSO. This inefficiency must be cut back within two regulation periods of 5 years each. To calculate this inefficiency, a national efficiency benchmarking was carried out.⁵⁹

Firstly, a cost driver analysis was conducted. It turned out that the parameters “annual gas exit” and “pipeline area” suit best for comparing efficiencies.

In the next step, the BNetzA applied a “double-fold” benchmarking using the DEA methodology. “Double-fold” means that the DEA was applied to parameters with standardized capital cost on the one hand and without standardized capital costs on the other hand. The best efficiency value of both efficiency analyses was then chosen for the TSO. Efficient TSOs got an efficiency score of 100%.

Furthermore, an outlier analysis was conducted. Outliers with a very high efficiency received an efficiency score of 100%, outliers with an efficiency score of less than 60% received the lower bound of 60%. The latter was done to guarantee that such inefficient TSOs have a fair chance to remove their inefficiency over the regulation period.

The outcome of the efficiency benchmarking is shown in Table 9.

Table 9: Outcome of German TSO efficiency benchmarking

TSO	Efficiency score
E.ON Gas Grid GmbH	100 %
bayernets GmbH	100 %
E.ON Avacon AG	95.06 %
Saar Ferngas Transport GmbH	86.02 %
EWE Netz GmbH	100 %
GVS Netz GmbH	88.72 %
Gas-Union Transport GmbH & Co KG	100 %
Erdgastransportgesellschaft Thüringen-Sachsen mbH (ETG)	95.73 %

Source: BNetzA (2008).

⁵⁹ For the following see BNetzA (2008).

5 Conclusions

Usually, efficiency benchmarking is more an issue at the DSO level than at the TSO level. The main reason are the number of companies. In most European countries, only one TSO exists that calls for international approaches. But these international comparisons generally suffer from a lack of comparability. Transmission network operations of various countries differ from one another in size and structure. Furthermore, there are significant differences regarding the definition of activities included in transmission network operations and the principles used when recording financial statement data.

With regard to cost benchmarking at the DSO level, various approaches are used across Europe. Furthermore, efficiency benchmarking is applied under quite different regulatory regimes. While e.g. Sweden has applied an engineering-based reference model under an ex post regulation until 2007, Austria, Finland, Germany and Norway are using frontier-based methods under ex ante incentive regulations. Denmark has established a kind of a rolling benchmarking procedure that is carried out annually.

Concerning frontier-based approaches, the lower the number of potential benchmark candidates (i.e. the number of DSOs), the more effort is spent to combine several parameters into one single parameter in order to preserve sufficient degrees of freedom. If too many explanatory variables are applied to samples of only a few observations, the regulator will be left with 100% efficient network operators.

One of the most crucial aspects is the treatment of capital costs. Efficiency benchmarking aims at comparing the efficiency of individual system operators in relation to a production frontier. This assumes that companies of the same sample are comparable. Usually, network operators have different investment cycles, apply different depreciation periods, and recognition of assets in cost calculations varies significantly across companies. Therefore, most regulators perform some kind of cost standardization.

What has become obvious from the review of the various countries is that several regulators still lack sufficient power. When it comes to final decisions about certain parameters (as e.g. the frontier shift), the determination is often a result of a bargaining process between the industry and the designated Ministry rather than a decision made by the regulator based on sound and transparent economic analysis. This is in particular true when incentive regulations are established for the first time. The general lack of transparency worsens, when information for transmission networks is required.

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