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The Cost of Producing Electricity in Denmark

A Technical Companion

Clinton J. Levitt and Anders Sørensen

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Foreword

The dynamics of the costs of generating electricity as well as the costs of maintaining a secure and reliable supply of electricity are important determinants of Denmark's successful progression towards reducing the use of fossil fuels in its power system. Clearly, these costs need to considered when implementing policies aimed at minimizing greenhouse gas emissions from generating electricity. When introducing "green" technologies into a power system for generating electricity (wind turbines, for example), the costs of generating electricity, for a variety of reasons, may increase too drastically. Increasing costs could potentially reduce the standard of living of Danish consumers and deteriorate the global competitiveness of Danish industry through increasing producer and consumer prices. Importantly, prices might change to such an extent that the political support for further progress towards a fossil independent society vanishes. In other words, there are important trade-offs between progress towards a fossil independent society and the increase in the production cost of electricity.

The evolution of Denmark's power system to relying less on electricity generated from fossil fuels raises a number of important questions: How does the relatively quick introduction of non-conventional generating technology (wind turbines) into a national power system affect the costs of generating electricity? There could be large affects on generating costs if (1) the new technology generates electricity at a higher cost compared to the existing technologies in the power system; (2) existing technologies cannot be phased out at a similar pace as the new technologies are being phased in, leading to over-capacity in the power system; and (3), the requirements of the existing power system to meet certain types of electricity demand could change. These are important issues that need to be considered when countries choose to introduce new generating technologies electricity into their power system. Leading examples include increasingly relying on renewable sources of electricity like wind or the substitution between conventional fuel sources like natural gas instead of coal.

The main objective of this project is to study the costs of generating electricity in the Danish power system. Specifically, we calculate and then compare the costs of generating electricity across different types of electricity generating technologies. The study provides an opportunity to measure the trade-offs involved with introducing new technologies into a power system.

The results of the study are reported in a series of two papers: The present study paper as well as in Levitt and Sørensen (2014). The purpose of the present study paper is to present the detailed calculations involved with computing the levelised costs of generating electricity for nine different thermal and non-thermal generating technologies. Note that the results of the present paper are used as input in the analysis of aggregate costs of electricity production in Denmark reported in Levitt and Sørensen (2014).

The project was carried out by researchers affiliated with the Centre for Economic and Business Research (CEBR) at Copenhagen Business School. The study group consists of Lecturer Clinton J. Levitt, Tasmanian School of Business and Economics at the University of Tasmania and Professor Anders Sørensen, Copenhagen Business School. We are grateful for the financial support from the Rockwool Foundation. A special thanks goes to the reference group consisting of Professor Torben M. Andersen (chairman), Department of Economics, University of Aarhus, retired Executive Vice President Palle Geleff, Energy E2, and Associate Professor Emeritus

Jørgen Birk Mortensen, University of Copenhagen. The reference group tirelessly gave comments and asked questions. We would also like to thank Mathias Tolstrup Wester and Casper Winther Jørgensen for efficient research assistance. The contents of this work are the sole responsibility of the authors and do not necessarily represent the views of The Rockwool Foundation. The authors have no conflict of interest in this work.

Clinton J. Levitt and Anders Sørensen, Copenhagen, November 2014

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Chapter 1

Introduction

What is the consequence on the costs of generating electricity when a new technology is introduced into a country's power system? There could be large consequences for aggregate production costs if (i) the new technology is producing at a higher cost compared to the existing technologies in the power system; (ii) existing technologies cannot be phased-out at a similar pace as the new technology is phased in, leading to over-capacity in the power system; and (iii), the requirements of the existing power system to meet certain types of electricity demand change. These are all important questions to address when countries decide to move towards new technologies for generating electricity. Leading examples include introducing renewable energy sources like wind or the substitution of conventional energy sources like natural gas instead of coal.

The main objective of this project is to study the costs of generating electricity in the Danish power system. Specifically, calculating and then comparing the costs of generating electricity across different types of generating technologies provides an opportunity to measure the trade-offs involved when new technologies are introduced into a power system.

By investigating the case of Denmark, this study provides important new insights into the aggregate costs of generating electricity. Specifically, the actual average unit costs are estimated for the full generating capacity in the Danish power system. Denmark is a particularly interesting case to study because it is a world leader in terms of wind power penetration rates. In 2012, the wind power penetration rate in electricity consumption was equal to 30 percent, whereas it was equal to 34 percent for production, see International Energy Agency (2013). For comparisons, other regions are dwarfed by the Danish rates: The corresponding values were six percent for Europe, 3.5 percent for the US, two percent for China, and 2.5 percent for the world. The countries that are closest to Denmark in terms of wind power penetration rates are Portugal with 20 percent and Spain with 18 percent. Important lessons can be learned about the consequences of the relative rapid introduction of a large degree of wind power on the electricity generating system. In addition, studying wind power in Denmark is also interesting because the penetration rate increased over a short period of time. In 1985, the share of wind generating capacity was essentially equal to zero. By 2012, the penetration rate of wind power in electricity consumption had increased to 30 percent.

In this paper, we calculate the levelised costs for nine different classes of generators and provide a technical comparison across 7 thermal electricity generating technologies and 4 renewable generation technologies. The 7 thermal electricity generating technologies consist of (1) condensing generators, (2)back-pressure generators, (3)extraction generators, (4) combined heat-and-power (CHP) waste generators, (5) combined-cycle gas turbines, (6) single-cycle gas turbines, and (7) gas engines. The two renewable generation technologies are onshore and offshore wind turbines. We also provide a breis analysis of hydro and solar generation.

For all nine technologies we present detailed costs calculations for computing the levelised costs. The major cost components are which are capital costs, operation and maintenance costs, fuel costs, and emission costs. In chapter 2, we present detailed cost calculations for the seven thermal technologies, whereas in chapter 3 we present the results for non-thermal generation in Denmark.

The results reported in this paper are used as inputs in the analysis of the aggregate costs of generating electricity in Denmark reported in Levitt and Sørensen (2014). The analysis of aggregate costs of electricity generation presented in Levitt and Sørensen (2014) include a summary of the main results of the study which is targeted for readers that may not have time for more intensive reading, e.g., policy makers. The paper also included detailed description of the Danish power system with main focus on thermal electricity generation technologies and developments in global fuel costs and carbon prices as well as a detailed analysis of aggregate costs of electricity generation in Denmark. Finally, the methodology we use to compute levelised costs are also documented in Levitt and Sørensen (2014).

Chapter 2

Levelised Cost of Thermal Generation Units

2.1 Introduction

In this chapter, we present detailed calculations and analysis of the costs of generating electricity in Denmark. We focus on the largest sector in the Danish power system, thermal generation, whereas in the next chapter, we study wind generation as well as take a brief look at solar and hydro. For details of the Danish power system, see Levitt and Sørensen (2014). In our study of thermal generators, we calculated the costs for seven broad classes of generators:

1. Steam turbine: Condensing;
2. Steam Turbine: Back Pressure;
3. Steam Turbine: Extraction;
4. CHP Waste;
5. Combine Cycle Gas Turbine;
6. Gas Turbine;
7. Gas Engine.

For each class of generator we break down generation costs into capital costs, fuel costs, operation and maintenance costs and environmental costs. In addition, we calculate heat credits for CHP units. The exact methodology used to calculate each of the costs was described in chapter 3 of Levitt and Sørensen (2014). We use the results of the work on global costs presented in chapter 5 of Levitt and Sørensen (2014) to calculate fuel and environmental costs as well as heat credits for CHP units. The cost measures developed in this chapter are used in chapter 6 of Levitt and Sørensen (2014), where we present the aggregate costs (including all thermal and wind generation) and report the results of a number of sensitivity analysis.

Before getting into the specific details of the various costs calculations involved in the cost build-up for each class of generator, we first present in tables 2.1 and 2.2, the levelised generation costs for each class of generator. The production weighted average costs are reported in the first table, whereas in the second table, we present the contributions to aggregate costs. It is clear from the two tables that there existed substantial cost heterogeneity across the different classes of generators. That heterogeneity exists should not be surprising given the diverse set of generators operating in the Danish power system.

Table 2.1: Generator Levelised Costs, 1998-2011 (kr/MWh)

Year	Steam Turbine: Condensing	Steam Turbine: Back Pressure	Steam Turbine: Extraction	CHP Waste	Combined Cycle	Gas Turbine	Gas Engine
1998	1000.07	1462.93	278.75	494.13	318.89	858.32	407.76
1999	1280.61	1356.73	288.87	412.78	286.28	716.41	395.11
2000	1004.54	1645.71	347.04	403.78	372.39	906.89	476.86
2001	1548.61	1694.23	309.81	379.07	434.18	884.46	457.54
2002	1455.12	1602.65	306.11	391.14	317.58	802.03	422.71
2003	1110.56	1284.14	246.14	349.47	326.57	792.09	437.85
2004	2178.31	1579.03	361.52	425.89	301.96	805.03	437.89
2005	3016.26	1622.45	425.39	310.10	354.65	926.51	483.02
2006	1349.31	1596.19	243.03	313.68	371.21	957.50	567.70
2007	2155.21	1511.79	339.55	339.54	461.10	1128.14	661.80
2008	3352.58	1899.98	413.19	348.99	535.92	1262.77	688.73
2009	6936.79	2179.56	363.60	341.93	481.79	1239.29	709.46
2010	8395.69	1331.67	388.93	333.48	356.67	1361.90	669.23
2011	25784.94	1510.24	473.35	312.45	389.03	1441.49	738.10

[a] Costs are reported in real 2011 Danish Kroner (details of the conversion from nominal to real values are provided later in the chapter). The details of the cost-build up for each generator is described in the relevant subsections of the chapter.

The other striking feature of the costs reported in the two tables is the degree to which costs have changed in the 14 years that we study. This is particularly interesting given the transition the Danish power system underwent during these 14 years and continues to do so. We show throughout this chapter that the transition away from thermal generation, and in particular, coal-fired generation, has generally resulting in higher average costs of generating electricity.

The costs reported in table 2.1 indicate that condensing and back-pressure generators were more costly to operate relative to the other five classes of generators. Moreover, the per unit cost of the electricity generated by condensing generators increased quite significantly over the last decade. The main reason that the electricity generated by these generators were more costly relative to the other generators is that they had high capital costs due to small capacity factors. These generators had large fixed costs (overnight costs), and with low capacity utilization rates, the fixed costs are distributed across low levels of output, leading to high per unit costs. Indeed, the sharp increase in generation costs observed for condensing generators was due to sharp decreases in capacity rates (coal prices have also increased over this period). However, because these generators had low capacity rates, their share of aggregate production was small relative extraction generators (which had lower levelised costs). Table 2.2 shows that the contribution made by condensing and back-pressure generators to aggregate costs were less than extraction generators precisely because they generated a relatively small share of aggregate electricity.

Extraction generators contributed the most to aggregate generation costs, which is not a surprise given that more than 50 percent of electricity is generated by extraction generators. The electricity generated by gas turbines was also relatively costly. Again, the high costs were primarily due to low capacity rates causing high capital costs. The contribution to aggregate costs made by gas turbines was actually quite small relative to the other generators. Interestingly, the contribution to aggregate costs made by gas engines was quite high. The electricity generated from CHP generators was among the least costly, especially post 2005. The low relative cost was primarily due to waste generators not being affected by rising fuel prices.

Table 2.2: Contributions to Aggregate Costs, 1998-2011 (kr/MWh)

Year	Steam Turbine: Condensing	Steam Turbine: Back Pressure	Steam Turbine: Extraction	CHP Waste	Combined Cycle	Gas Turbine	Gas Engine
1998	100.32	96.98	156.90	9.14	15.69	27.08	40.44
1999	87.22	93.51	163.25	9.42	15.95	27.50	40.05
2000	99.05	97.17	171.44	10.26	22.63	33.79	50.26
2001	89.59	92.40	165.39	9.76	29.39	31.98	49.20
2002	84.65	95.32	150.78	9.63	32.11	27.60	43.93
2003	55.74	78.41	129.90	8.03	31.75	24.59	38.39
2004	57.34	86.64	171.05	10.29	35.01	30.61	44.67
2005	63.31	89.14	189.40	11.26	41.07	34.21	50.74
2006	58.11	68.61	130.84	9.23	40.10	29.31	41.25
2007	60.87	67.51	174.74	11.32	45.61	31.40	45.64
2008	64.02	82.58	204.46	12.97	57.40	37.80	52.31
2009	54.59	95.91	194.17	12.30	47.33	31.76	48.22
2010	53.47	76.05	189.19	10.69	40.49	31.47	51.44
2011	54.55	81.65	201.87	11.79	40.79	32.42	51.47

[a] Costs are reported in real 2011 Danish Kroner. See the notes to table 2.1 for additional information.

2.2 Steam Turbine: Condensing Generators

In this section, we calculate the generation costs for the class of condensing steam generators. This class of generators produce only electricity and historically served base load demand. Steam condensing generators are amongst the oldest Danish generators supplying electricity to Denmark's power grid. The average age of active condensing generators in 2011 was 40 years. The oldest active generator first produced electricity in 1966. Indeed, most of these generators are nearing their expected lifetime and are being phased out of the power system. In 1998 there were eight condensing generators supplying electricity. Three generators were scrapped, so by the end of 2011 there were five condensing generators supplying electricity. It is clear from figure 2.1 that steam turbine condensing generators have been a declining source of electricity since at least 1998.[1] Indeed, in 2011, condensing generators only dispatched about 60 GWh of electricity. In the late 1990s, these generators delivered just over ten percent of the total electricity dispatched by Danish generators (including wind turbines). However, their share of aggregate generation has been decreasing since at least 1998. By 2006 condensing generators dispatched less than five percent of electricity generated in Denmark. The spikes in output observed in 2000 and 2006 were primarily caused by negative supply shocks in Norway and Sweden which prompted these generators to use more of their capacity. In particular, low levels of hydro resources in Norway and Sweden prompted the increase in production.

The fact that these generators are being phased out of the Danish power system makes interpreting their costs difficult because they used little of their installed capacity. Low capacity factors drive up per unit capital costs and per unit fixed operation and maintenance costs. However, even though the average costs of generation are very large (in fact, they are the largest among all generators) these generators actually have less impact on aggregate costs, relative to other generators, because they delivered a small amount of electricity to the grid.

These generators primarily used three fuels: coal, heavy fuel oil and gas oil. The use of each of these fuels is presented in figure 2.2. Coal has been the main source of fuel for these generators. Burning coal has been decreasing since at least 1998: those generators using coal were either scrapped, or if not scrapped, began using heavy fuel oil more often. The large observed spike in heavy fuel oil observed in 2010 was due to a single generator switching from coal to fuel oil while still maintaining similar levels of production. Post 2010 the use

[1] Share is calculated as the percentage of total electricity delivered. Total delivered is the aggregate sum of electricity dispatched from all thermal and wind generators.

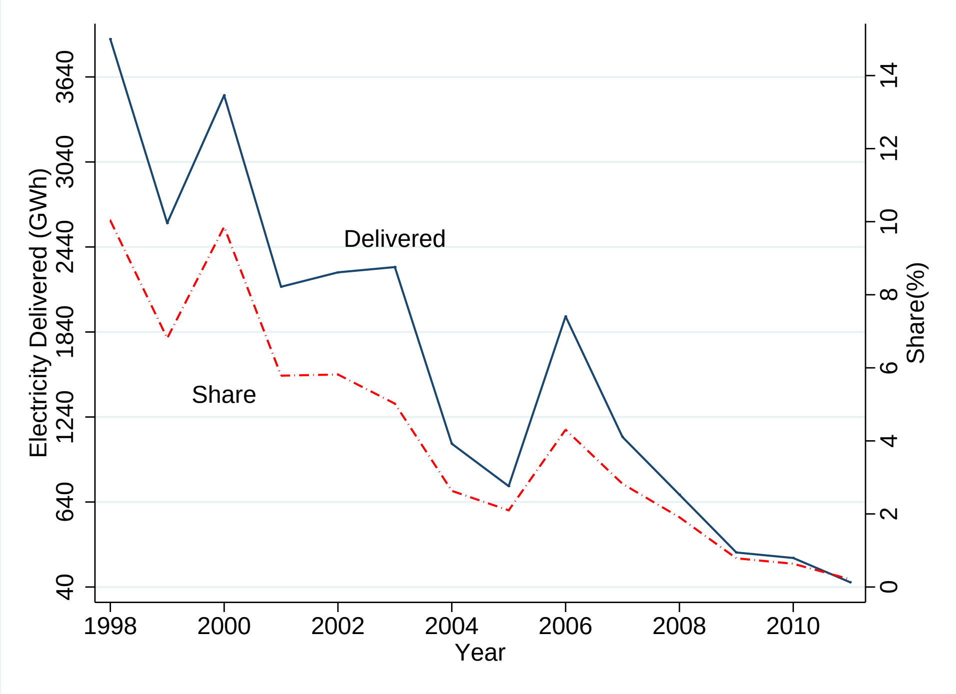

Figure 2.1: Aggregate Electricity Delivered, Condensing Generators 1998-2011

of heavy fuel oil essentially dropped off. The remaining generators primarily used gas oil as their main source of fuel.

The generation costs of condensing generators are constructed in the next few sections. Estimates of capital costs are constructed in the next section. Next, the results from sections 5.2.1, 5.2.3 and 5.2.4 of Levitt and Sørensen (2014) are used to calculate burner-tip costs. The results from section 5.3 of of Levitt and Sørensen (2014) are used to calculate environmental costs. Operation and maintenance costs are calculated next. The section concludes by presenting the aggregate levelised costs of generating electricity with these generators from 1998 to 2011.

2.2.1 Capital Costs

One difficulty with calculating the costs of capital for this class of generators arises from the diverse ages of the generators. Recall that one of the main determinants of capital costs are the construction and procurement costs of the plant and equipment (also called overnight costs). In other words, calculating capital costs requires observing, or having access to good approximations, the costs of constructing these plants at the date of their construction. Obviously, we cannot observe the actual construction costs of these plants. Therefore, we must rely on approximations. It is important to get the approximations of the construction costs for the period in which the plant was constructed as close as possible since construction costs have changed over time.[2] The good news, however, is that reliable estimates of overnight costs are available from a number of different sources and they provide a good approximation to the range of construction costs for these generators.

The best source of information concerning the overnight costs of these generators is from the Balmorel model of Denmark's power and heat system. The Balmorel model is a linear optimization model of power and heat systems originally developed to investigate power sectors in the Baltic region.[3] The Balmorel model has been

[2]See the discussion provided in chapter 3 in Levitt and Sørensen (2014) concerning the changes in construction costs overtime.
[3]See Grohnheit and Larsen (2001) for an extensive description of the sources of the data used in the model. In addition, Ravn (2012) provides a detailed description of the structure of the model.

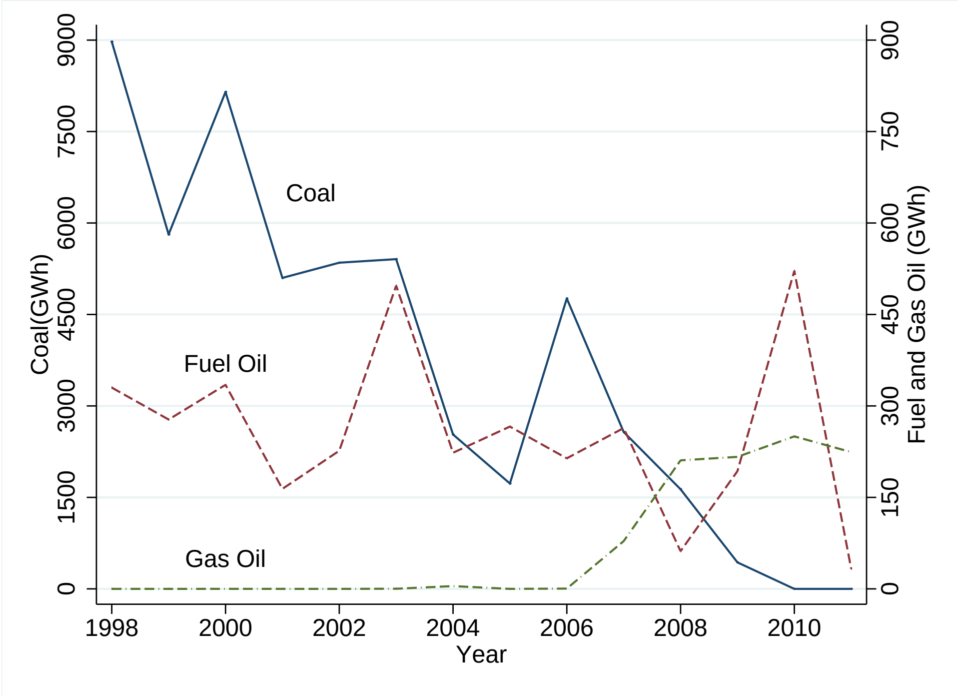

Figure 2.2: Fuels Used by Steam Condensing Generators, 1998-2011

used extensively to study various issues concerning the Danish power and heating systems.[4] The data used in the Balmorel model is likely the best estimate of overnight costs because it contains plant specific costs which are based on the vintage of the technology, size of the generators and the fuels they use. Importantly, for each generator we can assign a reasonably good estimate of the construction costs based on each generator's vintage, thermal capacity and fuel.

For coal burning condensing generators, the model reports an investment cost of €$1.275M_{90}/MW$ or $kr16.38M_{2011}/MW$ for old vintage plants (plants constructed prior to 1980).[5] The construction costs for generators using primarily heavy fuel were €$1.148M_{90}/MW$ or $kr14.74M_{2011}/MW$. Those generators burning gas oil had a construction cost of €$0.4M_{90}/MW$ or $kr5.13M_{2011}/MW$.

Computing levelised investment costs requires calculating the capital recovery factor (see equation (3.1) of Levitt and Sørensen (2014)) which depends on the interest rate, r, as well as on the lifetime of the generator. We used the interest rate that prevailed during the year that the generator came online. Lifetimes of the generators were computed using the observed lifetimes of those generators that were retired during the sample period. A lifetime equal to the maximum observed lifetime was assigned to those plants still producing during the sample period. We chose not to use the expected lifetime reported in various technology manuals because we observed that generators often operate beyond the expected lifetimes reported in these manuals.

The final component of capital costs is the capacity factor - see equation (3.2) of Levitt and Sørensen (2014) which we compute directly from the data.[6] In figure 2.3, we illustrate the annual average capacity factor for these generators over the sample period. It is clear from the figure that these generators operated far below their name-plate capacity. Even in the periods of peak use in 2003 and 2006, the average capacity

[4] For a very recent example see Zvingilaite (2013).

[5] The original cost data from the Belmorel model is reported in 1990 ECU/Euro. To convert to real 2011 DKK we used the ECU/Euro exchange rate equal to 7.857 (used in the Balmorel model to convert to ECU/Euro) and The Danish producer price index (PPI) for manufacturing industries. The Danish PPI is the *Price Index for Domestic Supply by Commodity Group* (series PRIS10).

[6] There is one issue concerning the calculation of the capacity factors. Some generators that were scrapped during the sample period do not list a nameplate capacity even for those years when the generator was operating. We used the average capacity factor, conditional on both year and the type of fuel, as proxies for the missing data.

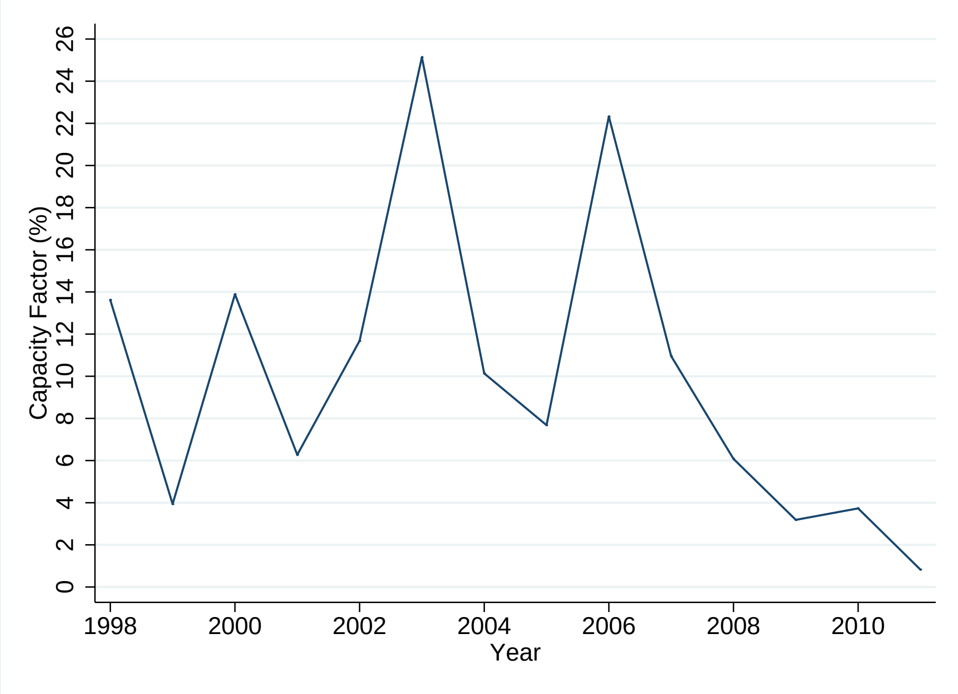

Figure 2.3: Capacity Factor for Steam Condensing Generators, 1998-2011

factor does not go above 26 percent. Capacity factors decreased quite rapidly after 2006, echoing the decline in the delivery of electricity by these units observed in figure 2.1. By 2011, these generators dispatched little electricity which resulted in capacity utilization rates dropping to less than one percent. These low capacity rates translated into extremely high capital costs per unit of output: fixed payments to capacity must be made regardless of how much electricity is dispatched. Indeed, increasing average costs as capacity rates decrease is an important characteristic among thermal generators. However, the contributions made by condensing generators to aggregate costs may be lower relative to the other classes of generators because they supplied a small fraction of the aggregate supply of electricity.

The levelised capital costs for condensing generators are illustrated in figure 2.4. The figure reports two series. The left axis reports the capital costs weighted by each generators share of electricity generated by condensing generators. From 1998 to 2003 capital costs were relatively steady. Capital costs began to increase after 2003 because of declining capacity factors. Capital costs started to increase significantly post 2006 when these generators were starting to be phased out of production. Low capacity factors resulted in large average costs because fixed costs must be paid regardless of how much electricity is being generated. The right axis illustrates the capital costs weighted by each generators share of aggregate generation (including all thermal generators and wind turbines). These costs should be interpreted as the contribution to aggregate levelised costs made by condensing generators' capital costs. Even though the capital costs of these generators were increasing quite drastically starting in 2006, the overall contribution to aggregate costs has been relatively steady since 1998. The large increase in capital costs due to very small capacity factors was offset by the fact that these generators delivered ever smaller amounts of electricity.

2.2.2 Fuel Costs

An overview of the costs of the various types of fuels is provided in table 5.1 of Levitt and Sørensen (2014). Recall that the costs reported in table 5.1 of Levitt and Sørensen (2014) have not taken into account the thermal

Figure 2.4: Capital Costs for Steam Condensing Generators, 1998-2011

efficiency of the generators burning the fuel. Thermal efficiency depends on the characteristics of the generator and is computed for each generator by taking the ratio of heat outputs to heat inputs. Specifically, the thermal efficiency for generator g, in period t, was calculated using

$$\eta_{ft} = \frac{output_{gt}}{input_{gt}}. \tag{2.1}$$

The thermal efficiency of each generator was calculated directly from data. In particular, the ratio given in equation 2.1 was computed using the observed heat content of the fuel burned by each generator, $input_{gt}$, combined with the observed amount of electricity delivered by the generator, $output_{gt}$. The annual average thermal efficiency is reported in figure 2.5.

There was very little change in the thermal efficiency of these generators between 1998 and 2006. After 2006, however, efficiency rates started to decrease, coinciding with reductions in the use of coal and fuel oil (see figure 2.2). Also illustrated in figure 2.5 are the burner-tip costs. The costs are also reported in table 2.3. Generators tended to use a combination of different fuels. Therefore, we calculated the annual costs of fuel for condensing generators in two steps. First, we calculated the weighted average fuel costs for each generator. The weights are the observed proportion of the different fuels that were used by each generator. Next, aggregate fuel costs for the class condensing generators were calculated by taking the annual weighted average of the fuel costs that were calculated in the first step. In this step, the weights used were each generator's share of total electricity generated only by condensing generators.

The data in the figure illustrates that burner-tip costs have been increasing since at least 1998. The rate at which fuel costs were growing increased substantially in 2006. One reason for the change in the growth rate was the substitution away from the lower priced coal in 2006 to higher priced fuel oil and gas oil (see figure 2.2). Both fuel oil and gas oil were more costly compared to coal (see table 5.1 of Levitt and Sørensen (2014)). Moreover, the switch to gas oil in the latter years had an important effect on costs: gas oil is much more costly relative to both coal and fuel oil. A second reason for the observed change was the decline in thermal efficiency.

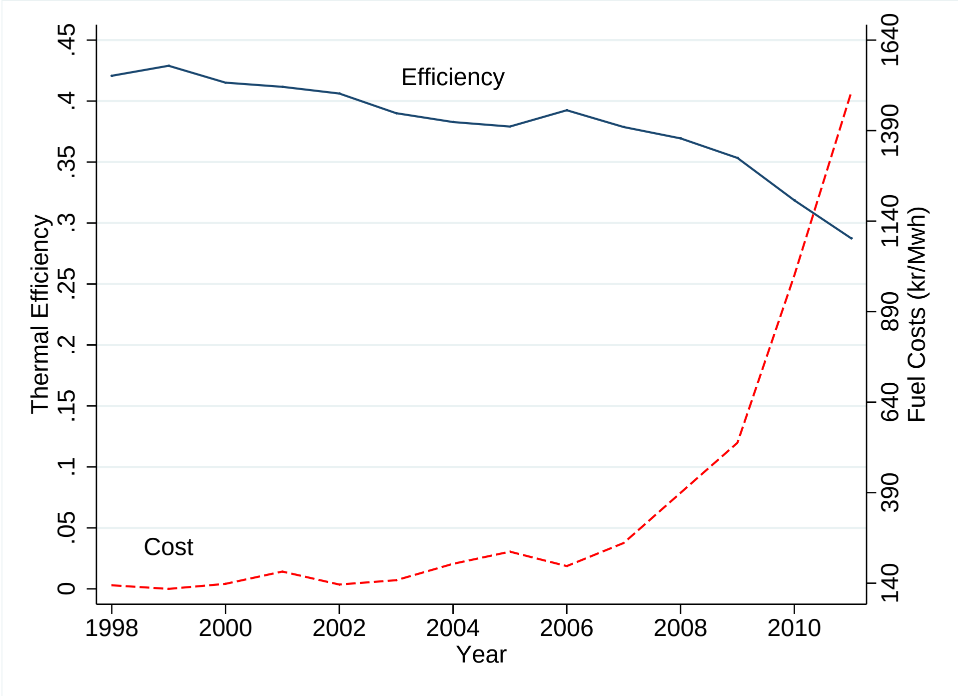

Figure 2.5: Burner Tip Costs and Thermal Efficiency, Steam Condensing Generators, 1998-2011

In figure 2.5, the increase in the growth rate of fuel costs maps closely to the decrease in the thermal efficiency of the generators. Lower thermal efficiency results in greater costs because more fuel is required to produce equivalent amounts of dispatched electricity.

2.2.3 Operation and Maintenance Costs

Two types of operation and maintenance (OM) costs were considered. The first are fixed operation and maintenance (FOM) which includes costs that are independent of how the plant is operated. These costs include administration, operational staff, planned maintenance, system charges and insurance among others. These annual fixed costs can also be thought of as additional costs of capacity: they must be paid regardless of the amount of electricity generated. The second type are variable operating and maintenance (VOM) costs which include consumption of auxiliary materials (water, lubricants), treatment and disposal of residuals, output related repair and maintenance. However, it is important to note that fuel costs are not included in VOM.

In their study of the costs of coal-fired electricity, McNerney et al. (2011) find that OM costs are the least significant of the three cost components. They find that OM costs for U.S. coal plants represent between 5 and 14 percent of total generation costs during the last century. It is difficult to acquire actual OM costs of Danish generators. However, the data used in the Balmorel model provide a good approximation of both FOM and VOM.

Coal fired generators are reported to have FOM costs of €$51,000_{90}/MW$ which is $kr74.79/MWh$ in real 2011 Danish Kroner. Generators burning primarily fuel oil have a FOM equal to €$45,900_{90}/MW$ which is $kr67.31/MWh$ in real 2011 Danish Kroner. The VOM costs for coal-fired generators were €$2_{90}/MWh$ or $kr25.64/MWh$ in real 2011 Danish Kroner. For generators burning primarily fuel oil the VOM costs were €$1.8_{90}/MW$ which is $kr23.12/MWh$ in real 2011 Danish Kroner.

On average, OM costs accounted for about five percent of total levelised costs. The maximum share of total levelised cost was approximately 23 percent. These shares are consistent with those reported by McNerney et al.

(2011). Although, care should be taken in interpreting the shares because total costs skyrocket post 2006.

2.2.4 Environmental Costs

Generators are subject to environmental regulation which generally increases the costs of generating electricity. Since 2005, generators have been required to purchase pollution permits for the right to emit carbon into the atmosphere. In particular, generators must hold a permit for each tonne of carbon emitted. These permits have prices and are traded in a market. We compute the costs of this regulation for each generator. Carbon expenditures, which we denote by CC, for generator g, in year t, were computed using

$$CC_{gt} = e_{gf} * F_{gt} * PC_t, \tag{2.2}$$

where e_{gf} is the emission factor for a specific type of generator, g, burning fuel f; F_{gt} is the total amount of fuel burned by the generator in year t; PC_t is the price of carbon.[7] The emission factors used to calculate the quantity of carbon emitted by the generators are those used by the Danish Energy Agency to calculate the Danish Emission Inventories.[8]

Recall that condensing generators primarily used three fuels: coal, fuel oil and gas oil. For each generator, the cost of carbon was calculated using each generator's share of the three types of fuels. So, for each generator, the cost of carbon is

$$CC_{gt} = \sum_f e_{gf} * \gamma_{fgt} * PC_t$$

where γ_{fgt} denotes the share of fuel f used by generator g in year t.

Cost are reported in table 2.3. Notice that there has been a large amount of volatility in these costs. The large fluctuations were caused by volatility in the spot market price of the permits. Have another look at the discussion provided in section 5.3 of chapter 5 of Levitt and Sørensen (2014) for the details.

2.2.5 Aggregate Generating Costs

The levelised generating costs for condensing are computed by summing the main costs calculated in the previous sections. Each of the main components are reported in table 2.3 along with the total levelised cost which is reported in the second-to-last column. Note that the costs are production weighted annual averages. Capacity costs was the main contributor to total costs followed by fuel costs. Operation and maintenance costs were of a third order importance. Capacity costs were particularly important in the latter years when capacity factors were really small.

Reported in the last column of the table are the annual contributions these generators made to aggregate generation costs. The contributions made to aggregate costs remain fairly consistent over the years even though the generator specific costs increased quite substantially.

2.3 Steam Turbine: Back Pressure Generators

Back pressure turbines are distinct from condensing generators in that they recover the heat that is produced while generating electricity, whereas the exhaust heat produced from condensing generators is wasted. Impor-

[7] The final units in equation 2.2 is kr. If the equation is $CC_{gt} = e_{gf} * PC_t$ then the units are kr/Mwh.

[8] The data is available from the Department of Environmental Science at Aarhus University: `http://envs.au.dk/en/knowledge/air/emissions/emission-factors/`. The factors were originally reported in kilograms per gigajoules (kg/Gj). The factors were converted to units $MTonne/MWh$ using the conversion $1kg/Gj = 0.0036MTonnes/MWh$.

Table 2.3: Aggregate Costs, Condensing, 1998-2011 (kr/MWh)

Year	Capacity Cost	Fuel Cost	Operation and Maintenance Cost[b]	Emission Cost	Total Cost	Contribution to Agg. Cost
1998	765.43	134.26	100.38	NA	1000.07	100.32
1999	1055.95	124.35	100.32	NA	1280.61	87.22
2000	765.91	138.22	100.41	NA	1004.54	99.05
2001	1276.03	172.16	100.41	NA	1548.61	89.59
2002	1218.53	136.31	100.28	NA	1455.12	84.65
2003	862.30	148.32	99.93	NA	1110.56	55.74
2004	1884.70	193.53	100.07	NA	2178.31	57.34
2005	2634.87	227.15	99.70	54.54	3016.26	63.31
2006	1016.18	187.25	100.25	45.64	1349.31	58.11
2007	1802.88	251.06	99.84	1.44	2155.21	60.87
2008	2863.17	389.57	99.78	0.06	3352.58	64.02
2009	6279.71	527.76	98.85	30.48	6936.79	54.59
2010	7278.96	990.06	97.04	29.63	8395.69	53.47
2011	24172.73	1495.59	91.83	24.79	25784.94	54.55

[a] Values reported in real 2011 Danish Kroner.
[b] Includes both fixed and variable operation and maintenance costs.

tantly, back pressure generators jointly produce power and heat which increases the overall efficiency of the generator–uses more of the energy content of fossil fuels. Consequently, back pressure turbines, also known as non-condensing turbines, are typically used in CHP systems and in industries that require process steam because they utilizes all of the exhaust steam for heating or processing purposes.

In Denmark, back pressure generators have historically been an important part of its district heating system. Over the last decade, however, the amount of electricity generated by back pressure generators in Denmark has been decreasing. Although, not to the same extent as condensing generators or extraction generators (which we study in the next section). We report the amount of electricity delivered by back pressure generators as well as their share of aggregate production in figure 2.6; the right axis reports their share are aggregate electricity production, whereas the left access reports the amount of electricity generated. For the years that we study, peak output occurred in 2003 (a response to low hydro reserves in Sweden and Norway). Since 2003, the amount of electricity generated from back pressure generators has been decreasing. There was a one-year increase in production in 2010, but electricity generation dropped the following year. Back pressure turbines' share of aggregate electricity output has generally been between seven and four percent. The latter years have seen their share of aggregate output decreasing.

2.3.1 Capital Costs

We begin our study of the costs of back pressure generators by calculating capital costs. The best source of good approximations to the overnight costs of back pressure generators are the parameters used in the Balmorel model. We assigned overnight costs to each of the back pressure generators in Denmark's power system by first categorizing them into three categories based on their thermal capacities (takes into account heat capacity) and the fuels they used. Generators with thermal capacities less than $30MW$ and which burned primarily coal or natural gas were assigned overnight costs equal to $kr1.18M_{2011}/MW$. Generators with thermal capacities between $30MW$ and $60MW$, and which burned coal or fuel oil were assigned overnight costs equal to $kr1.33M_{2011}/MW$. Large generators, those with thermal capacities greater than $100MW$, were assigned costs equal to $kr2.65M_{2011}/MW$. These large generators were primarily coal-fired.

Generating electricity involves large fixed costs (the overnight costs) implying that capacity factors have large

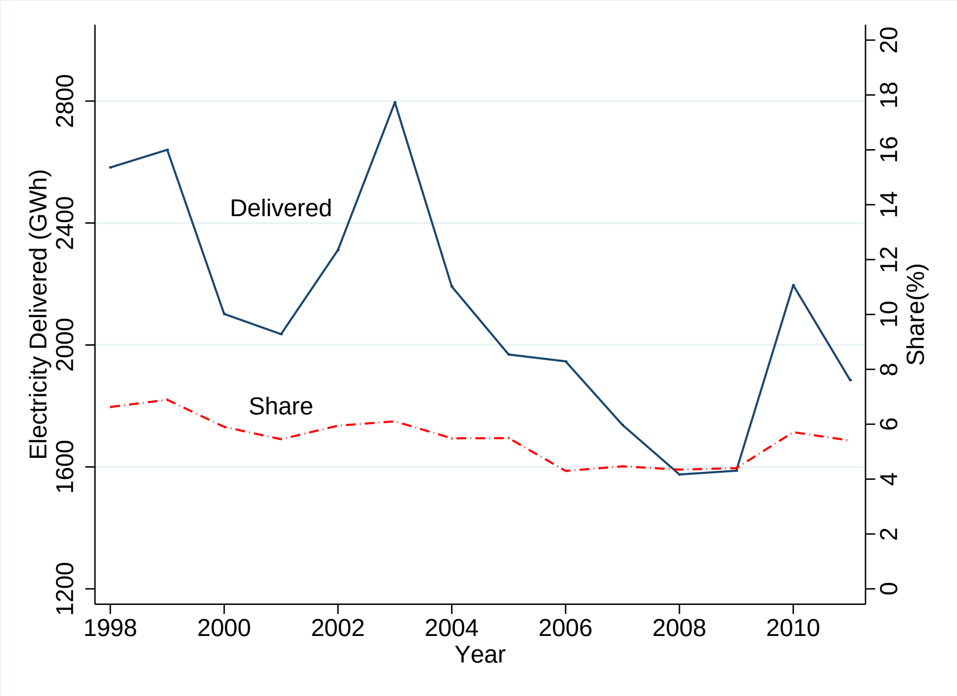

Figure 2.6: Aggregate Electricity Delivered, Back pressure Generators 1998-2011

effects on per-MWh costs. Indeed, our study of condensing generators in the previous section demonstrated the importance of capacity factors. Capacity factors are important because the fixed costs must be paid regardless of the amount of electricity being generated and because the amount paid is unaffected by the amount of electricity being generated. However, the existence of large fixed costs gives rise to economies of scale which means that average costs decrease when the quantity of electricity generated increases. The more electricity that a generator produces the more output over which the fixed costs can be dispersed. Consequently, higher capacity rates result in lower average costs.

In figure 2.7, we report the average capacity factor for back pressure generators. Capacity factors generally exhibit the same pattern of peaks and troughs observed in figure 2.6. There was a rather steep decline between 1999 and 2001 echoing the decrease in electricity generation in the same years. Capacity factors spiked in 2003 in response to low levels of hydro resources in Sweden and Norway. The period following the spike in 2003 was marked by decreasing generation rates, but interestingly, capacity factors did not change that much over this period. In fact, capacity factors just reverted back to their 2002 level and remained at that level until the large spike in 2010. A number of back pressure generators were decommissioned during this period which accounted for the decrease in production allowing the generators that remained to maintain their capacity rates.

The last two determinant of capital costs are the interest rates and lifetime. The interest rates are the same bond rates used previously. The lifetime of the generators was determined in two ways: first, if a generators was decolourised between 1998 and 2011, then the lifetime used to calculate capital costs was the generator's observed lifetime; second, for those generators that remained active, the lifetime is equal to the maximum observed lifetime. Again, we choose not to use expected lifetimes since realized lifetimes are often different and we would rather use the information in the data.

Capital cost are presented in figure 2.8. Once again, we present two series in the figure: the right axis reports the weighted capital costs which should be interpreted as contributions to aggregate generation costs; the left axis reports the average cost of capital for back pressure generators. Capital costs have been decreasing overtime primarily due to high-cost generators with low capacity factors being decommissioned. Overall, there

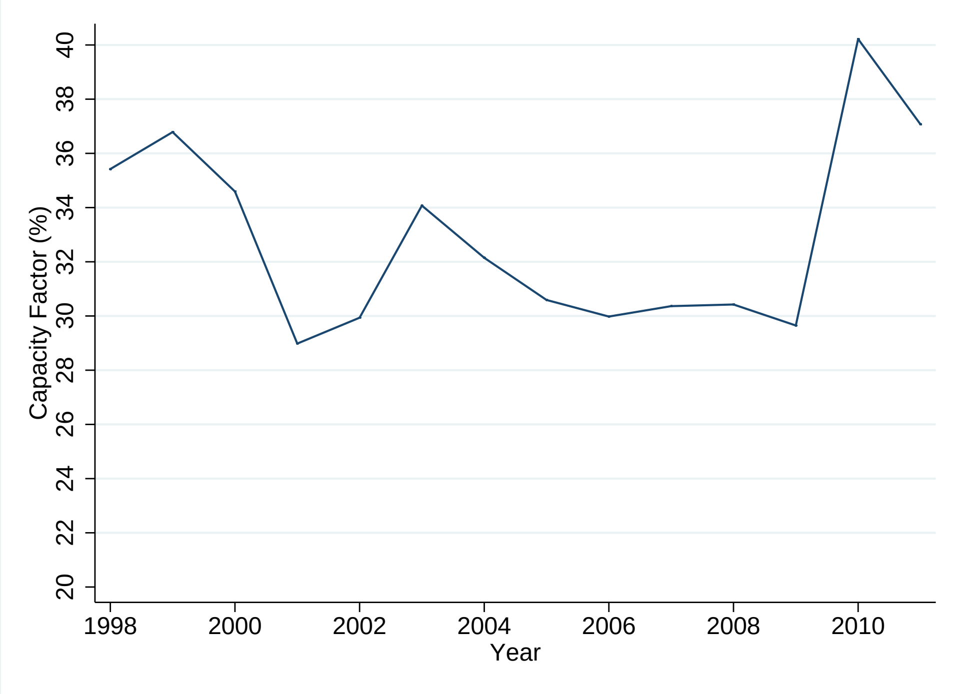

Figure 2.7: Capacity Factor, Back Pressure Generators, 1998-2011

was an 11 percent decrease in costs between 1998 and 2011. Although, care should be taken when interpreting this 11 percent decrease because of the large annual fluctuations of costs: the largest capital costs were observed in 2009. The large annual fluctuations were caused by changes in capacity factors. Note the inverse relationship between capacity rates and per-MWh capital costs. For example, the one period decrease in costs observed in 2003 was caused by the spike in capacity rates. The contribution that capital costs made to aggregate costs has also been decreasing since at least 1998.

2.3.2 Fuel Costs

Back pressure generators used a number of different fuels between 1998 and 2011. The primary fuels were coal, natural gas, heavy fuel oil, and a combination of wood, straw and biomass. Interestingly, substantial changes occurred to the input shares of these fuels, which we illustrate in figure 2.9. Coal was the main source of fuel until 2005, supplying between 50 and 30 percent of all fuel. Over this same period, however, coal's share of total fuel inputs was decreasing. In fact, by 2011, coal accounted for less than 20 percent of the fuel consumed by back pressure generators. While coal use was decreasing, back pressure generators were consuming more straw, wood and biomass so that by 2006 the combination of wood, straw and biomass surpassed coal as their main source of fuel. Indeed, by the end of 2011, wood, straw and biomass, accounted for almost 65 percent of total fuel consumed by back pressure generators. The consumption of coal, natural gas, and heavy fuel oil by back pressure generators was decreasing, while the consumption of straw, wood and biomass increased. Generators were substituting away from nonrenewable fuels and using more renewable fuels, straw, wood and biomass.

We should expect that the changes in the input shares, illustrated in figure 2.9, to have an effect on aggregate fuel costs. First, we look at efficiency rates. The substitution away from coal as well as natural gas to using straw, wood and biomass did not have much effect on efficiency rates. Efficiency rates ranged between 0.24 and 0.27 and any changes in the rates that did occur were not correlated with changes in fuel shares. Consequently, any effect on costs will not be through changes in efficiency rates.

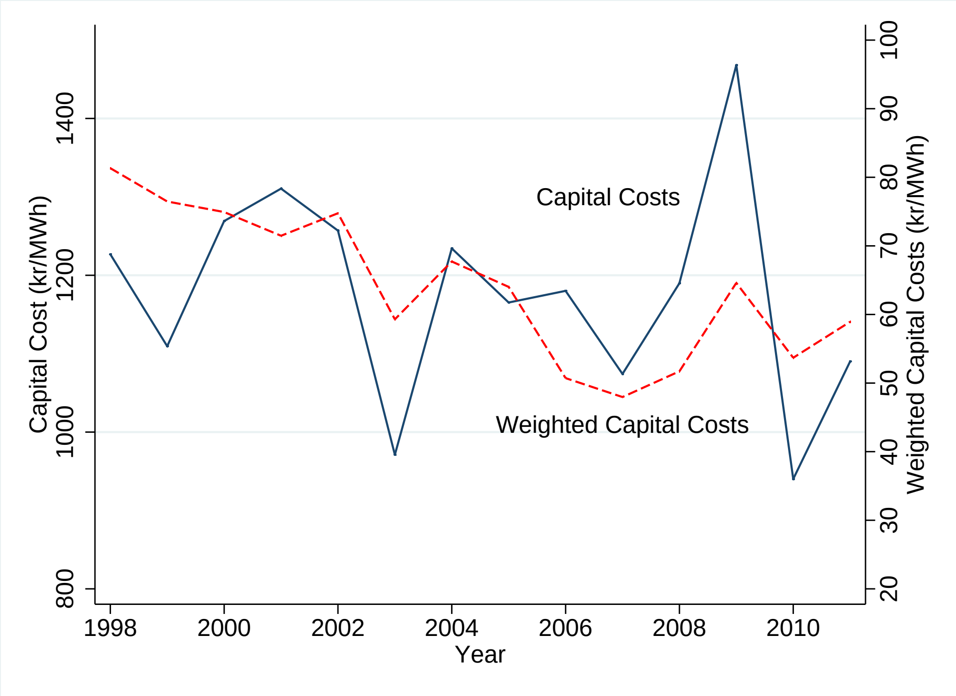

Figure 2.8: Capital Costs, Back Pressure Generators, 1998-2011

The observed increase in costs illustrated in the figure must be due to price effects. There were two mechanisms at work. First, in general, coal was cheaper relative to straw, so part of the increase in costs was causes by switching away from low-cost coal to high-cost straw. Second, the cost of coal, natural gas, fuel oil and straw were all increasing over most of the 2000s. The general increase on the costs of fuels also contributed to the increasing illustrated in the figure. The large two year increase in fuel costs observed in 2008 and 2009 was due to large increases in the costs of fuels. In particular, the cost of straw increased by over 88 percent, whereas the cost of coal increased by 40 percent.

2.3.3 Operation and Maintenance Costs

We split operation and maintenance costs into a fixed component and a variable component. Fixed operation and maintenance costs do not depend on the quantity of electricity generated, whereas variable operating and maintenance costs are depending on output. We obtained approximation of fixed and variable costs from the parameters used in the Balmorel model. We assigned costs based on thermal capacities.

Small generators, those with thermal capacities less than $30MW$, were assigned fixed operating and maintenance cost equal to $kr53.85_{2011}/MWh$ and a variable cost equal to $kr27.75_{2011}/MWh$. Large generators, those with thermal capacities great than $100MW$, were assigned fixed operating and maintenance costs equal to $kr121.16_{2011}/MWh$ and a variable cost equal to $kr32.12_{2011}/MWh$. Finally, intermediate generators were assigned fixed operating and maintenance costs equal to $kr60.58_{2011}/MWh$ and a variable cost equal to $kr31.22_{2011}/MWh$.

The weighted average aggregate operating costs for back pressure generators (fixed plus variable) was $kr.149_{2011}/MWh$. The average contribution to total costs was $kr8.17_{2011}/MWh$.

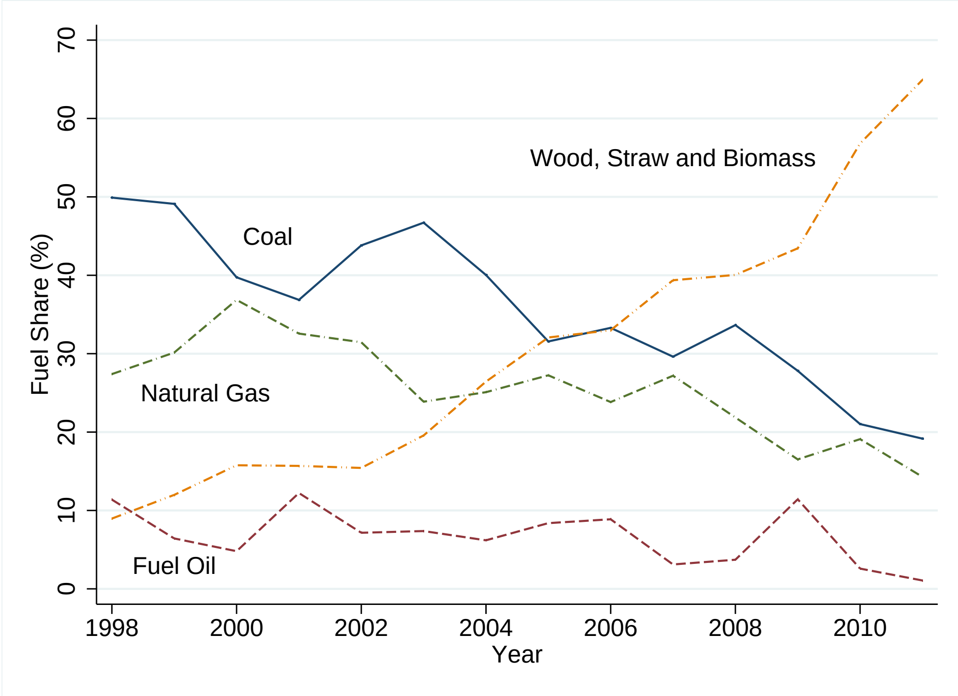

Figure 2.9: Fuels, Back Pressure Generators, 1998-2011

2.3.4 Emissions Costs

Emissions cost are determined by the fuels burned by the generators as well as by the permit prices. Emissions costs are reported in table 2.4. Emissions costs range from a high of $kr54.54_{2011}/MWh$ in 2005 to a low of $kr0.06_{2011}/MWh$ in 2008 when permit prices were extremely low. The substitution away from coal and heavy fuel oil, and to lesser extent, natural gas, to straw, wood and biomass also lowered emissions costs. However, changes in permit prices dominate any effects on costs through fuel substitution.

2.3.5 Heat Credits

The distinguishing characteristic of back pressure generators is that the residual heat produced while generating electricity is utilized in either district heating system or as processed heat which can be then used in industry. We want to calculate and then compare the costs of generating electricity. Useful comparisons across different generation technologies cannot be done without first accounting for the costs of heat production by CHP generators. For example, we cannot compare the costs of generating electricity from wind turbines to back pressure generators without adjusting the costs of back pressure generators for the heat that they produced. The costs of generating electricity from back pressure generators would be artificially high rendering any comparisons uninformative.

The standard approach to calculating electricity generating costs of CHP plants is to use heat credits. We described how we constructed heat credits in section 5.4 of chapter 5 of Levitt and Sørensen (2014). The average heat credit applied to the back pressure generators was $kr305.92_{2011}/MWh$. The maximum credit was $kr501.85_{2011}/MWh$, whereas the smallest credit was $kr170.41_{2011}/MWh$. Recall that heat credits are the levelised costs of a hypothetical replacement district heating unit with attributes similar to the CHP generator that produced the heat begin replaced. Therefore, heat credits respond to the same influences as the levelised cost of the actual generator: heat credits will change from year-to-year due to changes in fuel costs, for example.

The annual weighted average heat credit for the back pressure generators are reported in table 2.4. Average

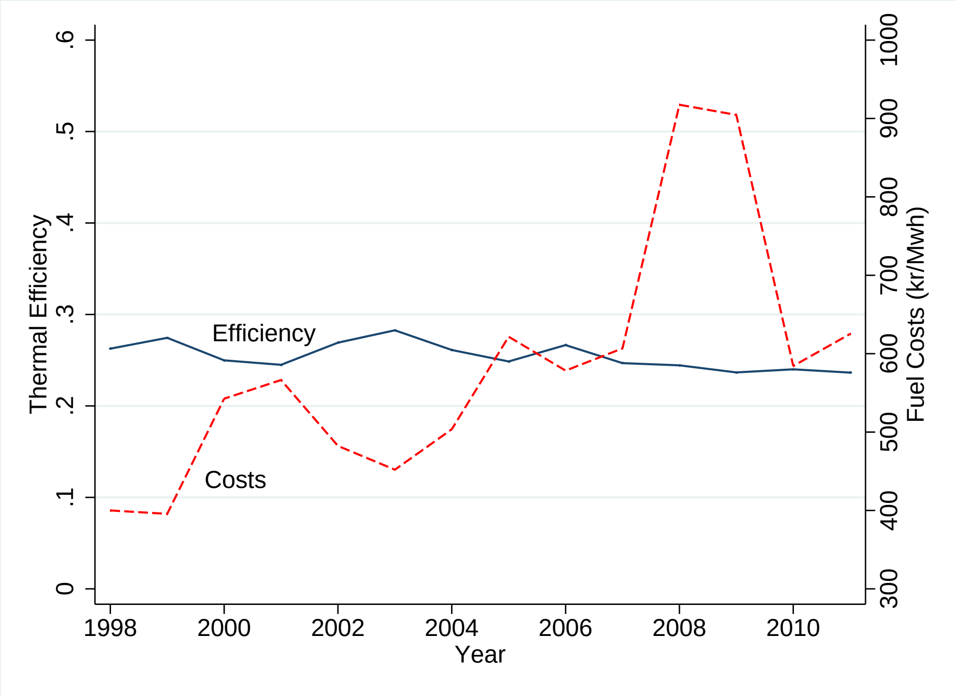

Figure 2.10: Burner-Tip Costs and Thermal Efficiency, Back Pressure Generators, 1998-2011

annual heat credits range from a high of $kr388.11_{2011}/MWh$ to a low of $kr286.29_{2011}/MWh$. The implied heating costs have been increasing since 2003 mostly due to rising fuel costs. One thing to keep in mind is that we assumed that the capacity factor of the replacement unit is constant overtime. This is an important assumption because changes in capacity rates can have large effects on capital costs. If we use the nameplate heat capacity ratings of the back pressure generators with the amount of heat produced, we get an average heat capacity rate of 0.46 with small annual fluctuations. So, we are likely understating the costs of the replacement technology.

2.3.6 Aggregate Costs

The various cost components that make-up aggregate costs are reported in table 2.4. In particular, in the seventh column we report the production weighted average aggregate costs. Aggregate costs are the sum of capital costs, fuel costs, operating and maintenance costs, emissions costs minus the implied costs of heat generation. Similar to the costs presented for the condensing generators, capital costs were by far the largest contributor to total costs. The second largest contributor was fuel costs. Interestingly, capital costs have been decreasing, whereas fuel costs have been increasing.

The levelised cost of back pressure generators experienced large annual fluctuations which were primarily caused by changes in capacity factors. There is no clear long run trend in the levelised costs. Even though capital costs were decreasing, there was a corresponding offsetting increases in fuel costs. Moreover, the large one-to-two year fluctuations in the levelised costs essentially makes long run trends less interesting. For example, there is a larger one-year increase in costs in 2009, resulting in the highest observed costs, but in the following year, costs dropped to the second lowest level observed over the 14 year period. The annual fluctuations essentially dominate any long run trend.

The second piece of new information reported in the last column is the contribution to aggregate generation

Table 2.4: Aggregate Costs, Back Pressure, 1998-2011 (kr/MWh)

Year	Capital Cost	Fuel Cost	Operation and Maintenance Cost[a]	Emission Cost	Heat Credit	Total Cost	Contribution to Agg. Cost
1998	1226.86	400.07	147.44	NA	311.44	1462.93	96.98
1999	1109.53	395.65	147.79	NA	296.25	1356.73	93.51
2000	1269.14	542.61	146.96	NA	312.99	1645.71	97.17
2001	1310.55	566.41	149.03	NA	331.76	1694.23	92.40
2002	1256.98	482.34	149.62	NA	286.29	1602.65	95.32
2003	971.09	452.00	149.97	NA	288.92	1284.14	78.41
2004	1234.24	503.60	149.18	NA	308.00	1579.03	86.64
2005	1165.29	621.64	149.18	53.49	367.16	1622.45	89.14
2006	1180.14	578.40	149.80	44.94	357.08	1596.19	68.61
2007	1074.16	606.75	149.44	1.40	319.96	1511.79	67.51
2008	1189.86	917.54	149.23	0.06	356.71	1899.98	82.58
2009	1468.14	904.58	149.34	32.94	375.44	2179.56	95.91
2010	940.15	584.31	150.19	36.81	379.79	1331.67	76.05
2011	1090.18	625.23	149.95	33.00	388.12	1510.24	81.65

[a] Includes both fixed and variable OM costs.

costs. These costs take into account both the aggregate costs reported in column seven and each generator's share of aggregate output, including the electricity produced by wind turbines. In contrast to the levelised costs reported in column 7, the contribution to aggregate costs made by back pressure generators has been declining since 1998. Although, there are large fluctuations in contributions in the latter part of the time series.

2.4 Steam Turbine: Extraction Generators

Extraction generators are generally large cogeneration plants producing both electricity and heat. These generators are the largest class of generators in terms of both installed capacity and electricity production. Indeed, these generators supply a large part of Denmark's base-load demand for electricity. The amount of electricity delivered by these generators is reported in figure 2.11. The left axis reports the amount of electricity delivered, whereas the right axis reports the generators' share of aggregate electricity supply. Even though there has been large annual fluctuations in dispatched electricity, especially in 2003 and 2006, there is a clear long run declining trend in the amount of electricity dispatched from these generators. Extraction generators produced just under 60 percent of domestically produced electricity in 1998 and 1999, whereas in 2011 these generators produced just over 42 percent of domestically produced electricity. It is interesting to note, however, that these generators consistently generated around 60 percent of the total electricity generated by thermal generators. Their relative importance amongst thermal generators has not changed that much from 1998 to 2011. The overall decline in generation is in part due to the growth of wind energy which has been replacing thermal generation over time.

The declining trend in production is consistent with the fact that a number of these generators had been decommissioned since 1998. In 1998 there were 17 generators operating. By the end of 2011, there were 12 generators producing electricity. Five generators had been scrapped amounting to just under $1322MW$ of scrapped capacity. This scrapped capacity represented approximately 25 percent of annual generating capacity. There is a mix of new generators and relatively old generators. The average age of active generators in 2011 was 26 years with ages ranging from 14 years to 44 years. Two new generators with an aggregate capacity of $772MW$ began supplying power to the Danish grid in 1997 and 1998.

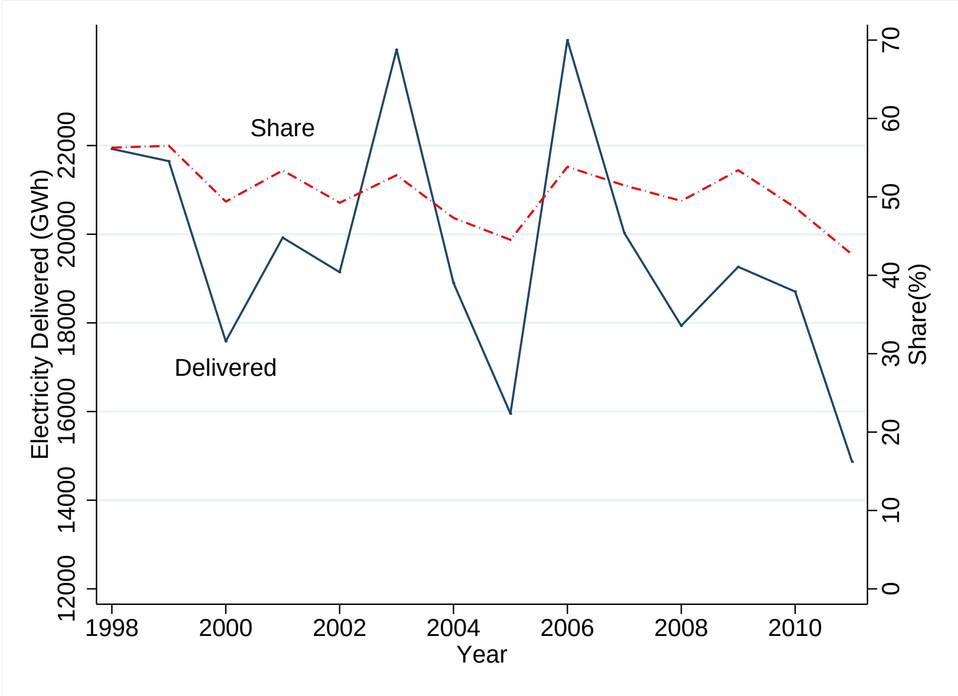

Figure 2.11: Electricity Delivered, Extraction Generators 1998-2011

2.4.1 Capital Costs

Extraction generators are different from condensing or back-pressure generators in one important dimension. The important difference is the degree to which steam can be extracted from the intermediate processes involved in generating electricity. In Denmark, the main use of the extracted steam is in the production of heat which is used in district heating systems. Recall from section 2.2 that condensing generators do not produce heat because steam is not bleed or extracted from the intermediate processes of the turbine generating electricity. Back-pressure generators, which were studied in section 2.3, generate heat for district heating systems through the bleeding off of the steam produced while generating electricity. A constraint with back-pressure technology is that the amount of steam that can be extracted while generating electricity is fixed. That is, steam is extracted at a constant rate. Extraction generators are distinct because steam is extracted in a controlled process. Importantly, the amount of steam that can be extracted is variable. The implication is that that operators can simultaneously respond to changes in the demand for electricity as well as the changes in the demand for heat by simultaneously choosing amount of electricity to produce and the amount of steam to extract.

The decision concerning how much electricity to generate and how much heat to produce are not entirely independent from each other. Producing more heat generally results in a reduced capacity for generating electricity. With an extraction steam turbine all the steam can be condensed to generate the maximum amount of electricity (similar to operating as a condensing generator). Another option is for all the steam to be extracted to be condensed at a higher temperature to generate heat (similar to operating as a back-pressure generator). Of course, some electricity generation capacity is lost when the generator is operating in back-pressure mode. The final option is for generators to be operated somewhere between condensing mode and full back-pressure mode. The generation of electricity and heat can be varied subject to some constraints by controlling fuel input and the amount of steam extracted.[9]

[9]For example, a generator may be constrained by a minimum generation capacity. The generator must operate above this capacity thereby restricting the range of steam that can be extracted to generate heat.

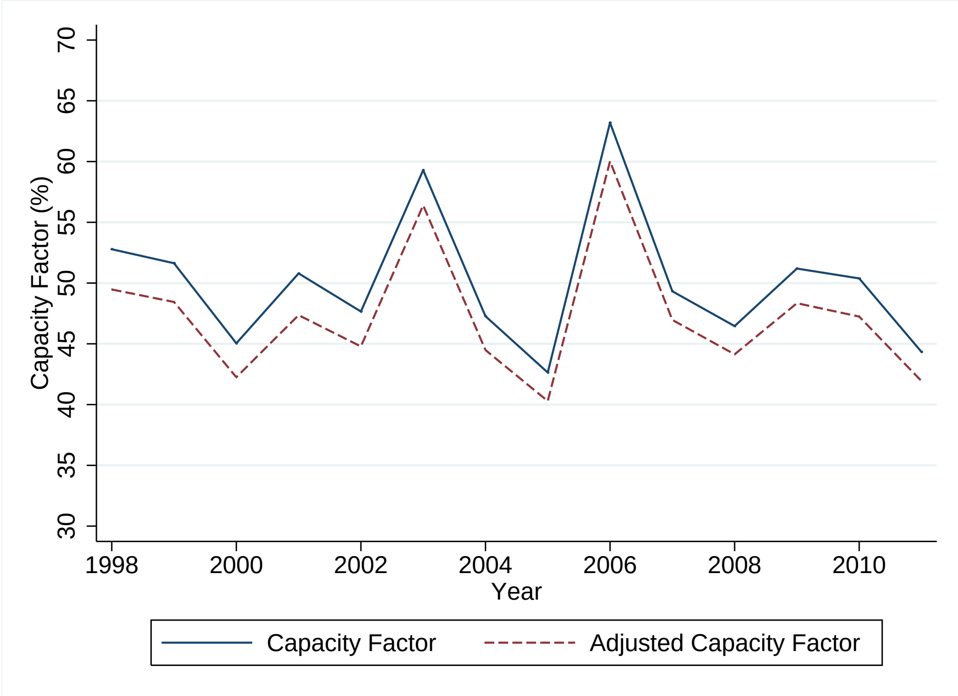

Figure 2.12: Capacity Factors, Extraction Generators 1998-2011

Operators face a tradeoff between generating electricity and producing heat. Let P_C denote the maximum electricity that can be generated if no steam is extracted (condensing mode) and P_B be the maximum electricity that can be generated when the generator is operating in full back-pressure mode. The loss of electricity generation capacity when going from condensing mode to full back-pressure mode is $P_C - P_B$. The loss of electricity generation capacity when operating somewhere between condensing and full back-pressure can be approximated using a linear relationship between electricity generation capacity and the amount of heat produced. In particular, let c_v denote the loss coefficient which measures the loss of electricity generation per unit of heat generated. If the generator is operating at full capacity, then the available electricity generation, E_e, can be represented using the linear model

$$E_e = P_C - c_v H_e \tag{2.3}$$

where H_e denotes heat production.[10] In the data, the loss coefficient, c_v, ranges between 0.15 and 0.2. Adjustments are made to capacities using the linear model given in equation 2.3 when calculating the levelised investment costs.

The average annual capacity factors are reported in figure 2.12. The figure includes both the adjusted and unadjusted capacity factor. The adjusted capacity factor uses the loss coefficient to calculate the electricity capacity available for generating electricity given the amount of heat produced by the generator. The data in the Balmorel model reports c_v values for the different generators in our data; we use these values to calculate the adjusted capacity factors. The heat adjusted capacity factor is lower than the unadjusted capacity factor; however, the difference is not substantial. The average difference between the two capacity factors is just under 3 percent. Capacity factors tend to vary from year-to-year based on fluctuations in demand and potential supply. There is no clear long run trend in the capacity factors indicating that the decrease in the supply of electricity by these plants illustrated in figure 2.11 was accomplished through the retirement of capacity.

A consistent theme in constructing estimates of the capital costs of the first two generators is the difficulty

[10] Additional details concerning the thermal properties of these generators are provided in Danish Energy Agency (2005) as well as in Danish Energy Agency (2012b).

Figure 2.13: Capital Costs, Extraction Generators 1998-2011

in obtaining accurate estimates of the overnight costs of each generator. Again, the best source of these costs in the Balmorel model. The Balmorel model list estimates of costs for extraction generators based on capacity, fuel and vintage. The investment costs range from $kr9.44M_{2011}/MW$ to $kr16.38M_{2011}/MW$. The mean was $kr12.9M_{2011}/MW$.

The final parameters required to calculate the levelised investment costs are interest rates and lifetimes of the generators. The same rule is applied for calculating the lifetime of these generators as was applied to the previous two generators. A generator's lifetime is equal to the observed lifetime if the generator was decommissioned. Expected lifetime is equal to maximum observed lifetime for those generators there were still active in 2011. The interest rate used in the calculation are those prevailing during the year the generator went online.

Levelised capital costs are reported in figure 2.13 and the values are reported in table 2.5. There is no clear long run trend in capital costs nor in their contributions to aggregate costs. The two large drops in capital costs observed in 2003 and 2006 were caused by the large spike in output which caused corresponding spikes in capacity rates. The contribution to aggregate costs was quite large relative to both condensing generators and back-pressure generators. The larger relative contributions was due to the extraction generators' share of total electricity output being much larger than the others.

2.4.2 Fuel Costs

Extraction generators used a variety of fuel. The five most important fuels are reported in figure 2.14.[11] It is clear from the figure that coal was the dominant fuel input over the sample period for these generators. Coal had around a 90 percent share of aggregate fuel inputs since at least 2003. The increase in the share of coal observed in 2003 was cause by generators no longer using orimulsion. Coal prices will have a large influence on

[11]The other fuels that were used by the generators but not included in figure 2.14 include waste, biooil, biogas, gas oil and woodchips. Each of these fuels accounted for less than a quarter percent of aggregate fuel use. Most of these fuels were used once during the sample by a single generator. Their contribution to total costs are negligible.

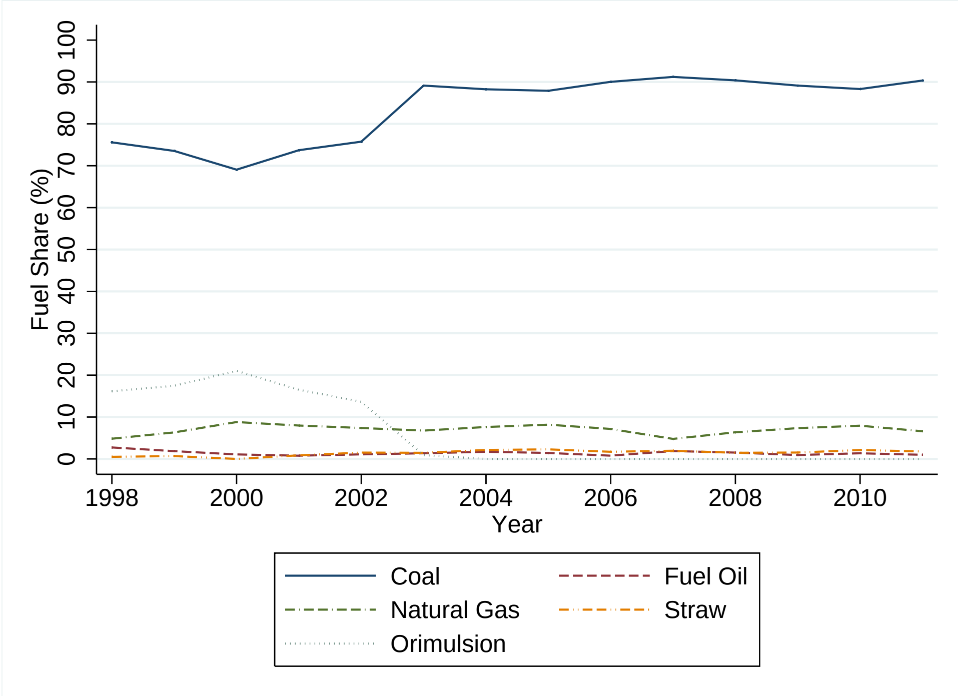

Figure 2.14: Share of Fuels, Extraction Generators 1998-2011

aggregate burner tip costs. Natural gas was the second most used fuel averaging around a seven percent share over the period. Straw was also used and has a share of just over one percent.

There was very little change in the mix of fuels after generators ceased using orimulsion by 2004. Orimulsion was an important fuel input in the late 1990s and early 2000s supplying nearly 20 percent of fuel in 2000. Beginning in 2000 generators began substituting orimulsion with coal so that by 2004 orimulsion was no longer used.

The burner tip costs for extraction generators is reported in figure 2.15. Two series are reported in the figure. The right axis reports average thermal efficiency across generators, whereas the right axis reports the average burner tip costs. Thermal efficiency largely remained unchanged over the years. Average thermal efficiency was just under 40 percent over the 14 years. There was a slight increase during the period in which some generators started to substitute away from orimulsion. However, the increase in efficiency was very small. There was little change in average thermal efficiency because there was very little interfuel substitution over the years. Coal remained the dominant fuel for these generators.

Fuel costs increased over the 14 year period. Since there was no significant change in average thermal efficiency over this period, the increase in costs was cause by changes in fuel prices. Increases in the costs of coal was the significant contributor to the increasing costs. Indeed, comparing figure 2.15 with figure 5.4 of chapter 5 in Levitt and Sørensen (2014) it is clear that the burner tip costs follow the fluctuations in the cost of coal. The spikes observed in 2001, 2003 and 2008 correspond to the spike in the cost of coal observed in figure 5.4.

2.4.3 Operation and Maintenance Costs

Fixed operating and maintenance costs were assigned to each generator based on the main type of fuel used by the generator as well as the capacity of the generator and vintage. The costs were obtained from the Balmorel model. Older generators had larger fixed costs relative to newer vintages. Generators burning primarily coal also had larger fixed costs relative to those burning alternative fuels. Generators with larger thermal capacities

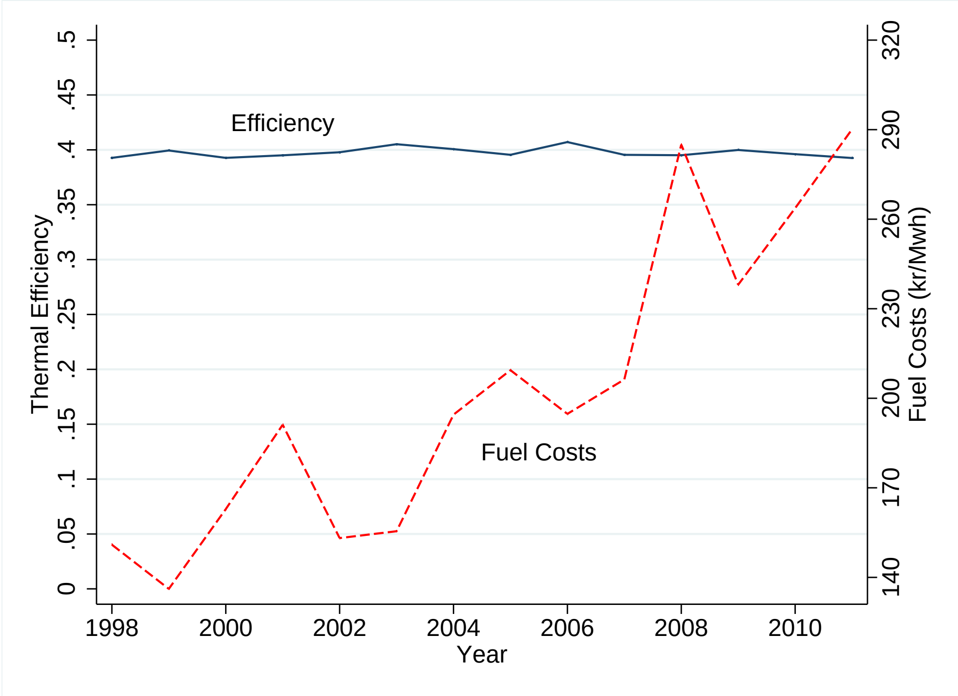

Figure 2.15: Fuel Costs, Extraction Generators 1998-2011

also had larger operating and maintenance costs. Fixed costs ranged from $kr43.14/MWh$ to $kr74.79/MWh$ (real 2011 Danish Kroner). The average fixed cost was $kr59.02/MWh$.

Variable operating costs were also assigned to each generator based on fuel, vintage and capacity. Variable costs ranged between $kr16.03/MWh$ and $kr27.79/MWh$ (real 2011 Danish Kroner). The average variable cost was $kr22.51/MWh$. The assignment of variable costs followed the same rules as those that applied to the fixed operation and maintenance costs.

The weighted average aggregate operating costs for extraction generators (fixed plus variable) was $kr78.49/MWh$. The average contribution to total costs was $kr39.85/MWh$.

2.4.4 Environmental Costs

The two major factors affecting emissions costs for extraction generators was the quantity of coal burned to produce electricity and permit prices. The fact that orimulsion was an important fuel prior to 2003 does not affect emissions costs because the EU ETS did not start until 2005. Emissions costs ranged from a high of $kr58.57_{2011}/MWh$ to a low of $kr0.06_{2011}/MWh$. The average emissions cost was $kr28.17_{2011}/MWh$. The changes in the costs of emissions were primarily caused by changes in the price of the carbon permits since there was very little interfuel substitution.

2.4.5 Heat Credits

Extraction generators are distinct from condensing and back pressure generators in that steam can be extracted in a controlled process which can then be used in district heating system. Similar to back pressure generators, in order to facilitate comparison of costs of generating electricity, it is important to account for the fact that these generators produce heat. We calculated heat credits for extraction generators. Recall that heat credits are determined by assuming that a hypothetical heat plant was installed to generate the heat that was generated by the extraction generators. The characteristics of the replacement heat plant was determined by the charac-

Table 2.5: Aggregate Costs, Extraction, 1998-2011 (kr/MWh)

Year	Capital Cost	Fuel Cost	Operation and Maintenance Cost[a]	Emission Cost	Heat Credit	Total Cost	Contribution to Agg. Cost
1998	367.50	150.96	80.81	NA	320.52	278.75	156.90
1999	372.97	136.15	79.52	NA	299.77	288.87	163.25
2000	414.53	162.86	79.48	NA	309.82	347.04	171.44
2001	364.80	191.13	79.20	NA	325.33	309.81	165.39
2002	382.02	153.17	78.51	NA	307.59	306.11	150.78
2003	318.21	155.46	79.58	NA	307.11	246.14	129.90
2004	407.51	194.51	77.51	NA	318.02	361.52	171.05
2005	458.32	209.42	77.18	53.81	373.34	425.39	189.40
2006	299.70	194.77	77.82	44.56	373.82	243.03	130.84
2007	384.33	206.31	78.83	1.44	331.35	339.55	174.74
2008	407.88	284.99	77.94	0.06	357.67	413.19	204.46
2009	379.50	238.05	77.06	31.89	362.91	363.60	194.17
2010	389.59	263.69	77.56	34.99	376.89	388.93	189.19
2011	452.38	290.14	77.36	30.66	377.19	473.35	201.87

[a] Includes both fixed and variable OM costs.

teristics of the generator it hypothetically replaced. The important characteristics were capacity, primary fuel and vintage (refer back to chapter 5 of Levitt and Sørensen (2014) for specific details).

The average heat credit applied to the set of extraction generators was $kr337/MWh$ which is quite similar to the credit applied to back pressure generators. The range of credits across extraction generators was lower relative to the range for back pressure generators: The minimum credit was $kr217/MWh$ whereas the maximum credit applied to these generators was $kr485/MWh$.

The average annual heat credit is reported in table 2.5. Heat credits generally increased over the years due to increasing fuel costs. Annual credits ranged from $kr300_{2011}/MWh$ in 1999 to over $kr370_{2011}/MWh$ in 2011 and 2011.

2.4.6 Aggregate Generating Costs

The various cost components are summarized in table 2.5. Total costs of producing electricity from extraction generators generally increased between 1998 and 2011. Costs of producing a MWh of electricity was around $kr280$ in 1998 and 1999. By 2011, costs increased to over $kr470/MWh$, an increase of approximately 67 percent. Costs increased over the period because of increases in fuel costs and reductions in capacity rates. There were two years in which costs dropped: In 2003 and 2006, costs declined because of increases in capacity rates.

In column eight of the table are reported the contribution to aggregate generation costs made by extraction generators. The contribution to aggregate costs increased by approximately 30 percent. Even though the costs of the electricity generated from extraction generators increased by approximately 67 percent, because their share of aggregate electricity output has been decreasing, their contribution to aggregate only increased by 30 percent.

2.5 CHP Waste

Waste-to-energy plants incinerate waste to produce energy. In Denmark, waste-to-energy plants are combined heat an power plants generating both heat and electricity by primarily incinerating municipal solid waste. Often,

Figure 2.16: Aggregate Electricity Delivered, CHP Waste Generators 1998-2011

municipal waste is delivered by truck and is normally incinerated in the state in which is arrives. Standard CHP waste plants with capacities between 30 and 100 MW will use between 10 and 30 tonnes of waste per hour (Danish Energy Agency (2005)). Typically, a CHP waste plant has a steam boiler which produces steam which is then sent to a steam turbine which drives a power generator. The residual heat is recovered for the production of district heating. Most plants in Denmark are configured with a back pressure turbine meaning heat and power of produced in a constant ratio. In 2003, approximately 3.3 million tonnes of waste was incinerated for the production of electricity and/or heat.

CHP waste plants are an important component of the Danish energy sector in terms of producing heat and electricity. In fact, in contrast to almost all other thermal generators, electricity generated by CHP plants has been increasing since at least 1998. The amount of electricity generated by CHP plants is reported in figure 2.16. From 1998 to 2004, there was a modest increase in the amount of electricity generated by CHP plants. However, from 2004 to 2006, there was a sharp increase in the amount of electricity generated due to three CHP waste plants joining the power sector. These plants added approximately 50MW of additional electricity generation capacity to the Danish power system. Moreover, only one plant was decommissioned resulting in withdrawing 4MW of electricity generation capacity from the system. So, since 2004, there has been a net increase of approximately 46MW of electricity generating capacity. Overall, the amount of electricity generated by CHP plants increased by over 80 percent between 1998 and 2011.

The increase in the amount of electricity generated by CHP waste plants resulted in an increase in their share of aggregate electricity generated in Denmark. Again, CHP waste plants is one of only two thermal generating classes (the other being combined-cycle gas turbines) which experienced an increase in their share of aggregate electricity generation. Their share of total electricity output increased from about 2 percent in 1998 to just under 4 percent in 2010.

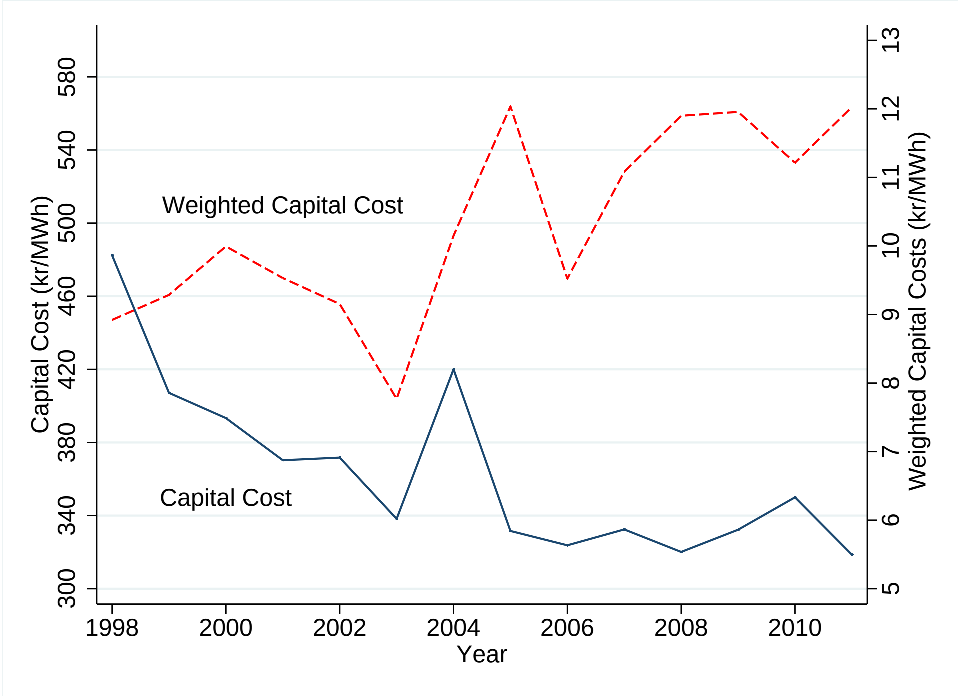

Figure 2.17: Capital Costs, CHP Waste Generators, 1998-2011

2.5.1 Capital Costs

Examining the capital costs of CHP waste plants reveals an interesting dynamic. Average annual capital costs as well as their contribution to aggregate costs (right axis) are reported in figure 2.17. Average capital costs decreased from around $kr480_{2011}/MWh$ in 1998 to less than $kr320_{2011}/MWh$ in 2011: a decrease of about 33 percent. However, even though average capital costs decreased over the sample period, their contribution to aggregate generating costs actually increased. Average capital costs and their contributions to total costs both generally decreased until 2003. Thereafter, capital costs continued to decline (after a one-year spike in costs) and would do so through to the end of the sample period, while contributions to aggregate costs began to increase. That contributions to aggregate costs increased over this period, while capital costs declined, is explained by the fact that the share of aggregate electricity generated by CHP waste plants increased over this period. Indeed, the substantial increase in contributions observed after 2003 is correlated with both the increase in the amount of electricity generated and production shares observed in figure 2.16.

The decrease in capital costs can be explained by the increase in average annual capacity factors for CHP waste plants. The average annual capacity factors are reported in figure 2.18. In contrast to almost all other thermal generators, the capacity factor of CHP waste plants actually increased. The observed increase in capacity factors was significant. Capacity factors increased from approximately 62 percent to over 75 percent. Comparing figures 2.17 and 2.18 reveals that there is a negative correlation between capacity factors and capital costs: per MWh costs decline as more electricity is generated. Once again, it is clear that economies of scale is an important driver of production costs.

Here we turn to the assumptions behind the results reported in the previous two figures. We assumed that the maximum lifetime of a generator is 35 years. However, if a generator was scrapped during the sample period, then the lifetime of the generators was the observed lifetime. The maximum age of a CHP waste generator was 22 years. It was difficult to obtain data on overnight costs based on capacity and vintage. However, in the case of CHP waste plants in Denmark, vintage and capacity are not as important relative to the previous generators

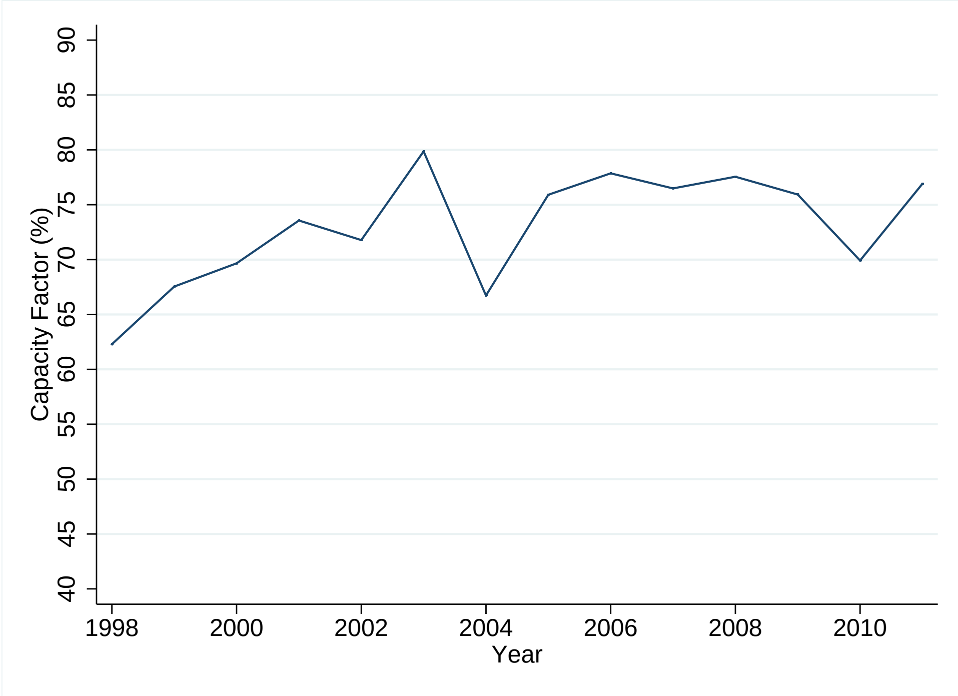

Figure 2.18: Capacity Factor, CHP Waste Generators, 1998-2011

since there is relatively less variation. We used the nominal cost data reported in the Balmoral model in our calculations. In particular, the overnight costs for each plant was assumed to be $kr25.5M_{2011}/MW$.

2.5.2 Fuel Costs

CHP plants in Denmark primarily burn municipal waste. However, in some instances, generates will also burn straw to produce heat and electricity. Between 90 and 95 percent of the fuel used by these generators is waste, whereas the remaining share is made up of straw. The costs of using waste as a fuel is called a gate fee. The gate fee is the actual cost for households or industry of having its waste collected and incinerated. We assume that the gate fee for waste used in CHP waste generators is $kr300_{2011}/MWh$. The costs of straw were computed in chapter 5 of Levitt and Sørensen (2014): costs ranged between $kr107_{2011}/MWh$ and $kr270_{2011}/MWh$. Efficiency rates were calculated to be around 20 percent as were fairly consistent over the sample period. The average burner tip costs ranged between $kr298_{2011}/MWh$ and $kr326_{2011}/MWh$. The annual variation of the burner-tip costs were due to changes in efficiency rates and changes the costs of straw. The burner-tip costs as well as average efficiency rates are reported in figure 2.19. The was no discernable long run trend in either efficiency rates or the burner-tip costs.

2.5.3 Operation and Maintenance Costs

Both fixed and variable operating and maintenance costs were obtained from the Balmoral model. Fixed costs were assumed to be $kr121_{2011}/MWh$, whereas variable costs were assumed to be $kr26.01_{2011}/MWh$. So, total operation and maintenance costs were $kr147_{2011}/MWh$. We assumed that each generator had the same operating costs.

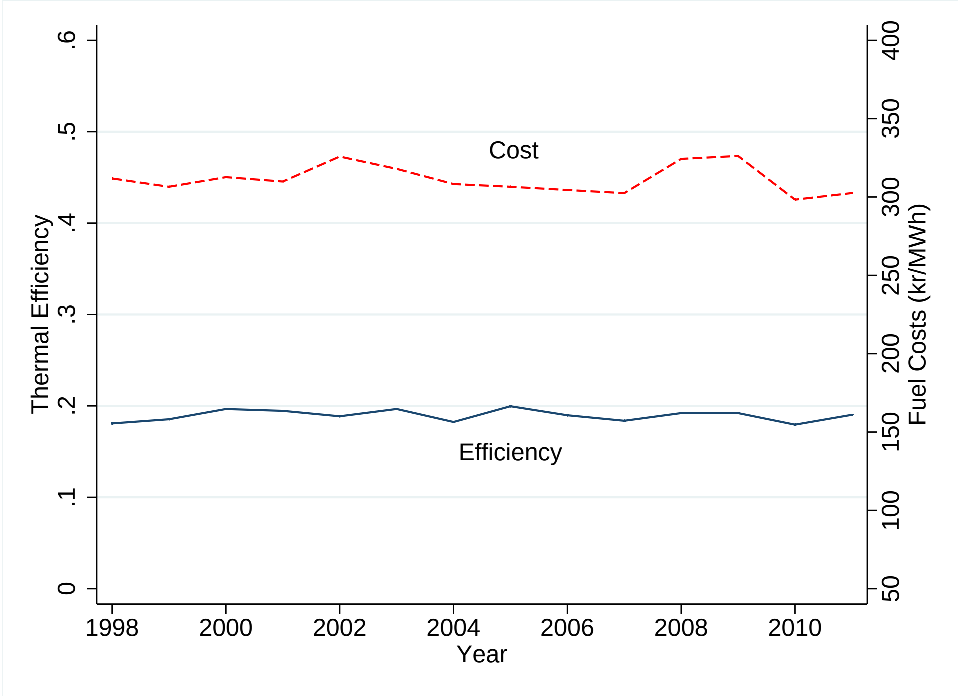

Figure 2.19: Burner Tip Costs and Thermal Efficiency, CHP Waste Generators, 1998-2011

2.5.4 Emissions Costs

Emission costs was determined by the amount of waste incinerated to generate electricity. The emissions cost of producing a MWh of electricity using waste ranged between $kr0.02_{2011}/MWh$ and $kr21.7_{2011}/MWh$ given a price for carbon existed.

2.5.5 Heat Credits

The heat credits that we computed for CHP waste heat generators were based on the levelised cost of a replacement waste-to-heat district boiler. The overnight costs as well as the operation and maintenance costs of the waste-to-heat district boiler was determined by the heat capacity of the CHP plant being replaced. We assumed that the gate fee was equal to $kr300_{2011}/MWh$. Heat credits applied to CHP waste generators ranged from $kr329.58_{2011}/MWh$ for the smaller generators to $kr578.44_{2011}/MWh$ for the larger generators (those with a thermal capacity greater than 100 MW). The average heat credit was $kr439.86_{2011}/MWh$.

2.5.6 Aggregate Costs

The various costs of generating electricity from CHP plants are reported in table 2.6. Total per MWh costs of generating electricity declined over the sample period. In 1998, the cost of generating a MHw of electricity was just below $kr500_{2011}/MWh$, whereas in 2011, costs were just over $kr300_{2011}/MWh$. Almost all of the reduction in costs was derived from reductions in capital costs. Fuel costs did not change much over the sample period since straw made up only a small percentage of fuel, changes in straw prices had only a small effect on burner-tip costs. Operation and maintenance costs were assumed to be the same for each generator. Capital costs declined over this period because of increasing capacity factors.

Notice, however, that CHP waste plant's contribution to aggregate generating costs do not exhibit the same declining trend observed for total costs. The reason is that these generators increased their share of aggregate production. Therefore, the costs of producing electricity with CHP waste plants gained in importance.

Table 2.6: Aggregate Costs, CHP Waste, 1998-2011 (kr/MWh)

Year	Capital Cost	Fuel Cost	Operation and Maintenance Cost[a]	Emission Cost	Heat Credit	Total Cost	Contribution to Agg. Cost
1998	482.44	311.84	147.18	NA	435.62	494.13	9.14
1999	407.13	306.54	147.18	NA	437.79	412.78	9.42
2000	393.34	312.67	147.18	NA	439.70	403.78	10.26
2001	370.29	309.87	147.18	NA	438.79	379.07	9.76
2002	371.73	325.81	147.18	NA	445.67	391.14	9.63
2003	338.22	317.97	147.18	NA	445.80	349.47	8.03
2004	420.02	308.27	147.18	NA	440.54	425.89	10.29
2005	331.60	306.54	147.18	20.10	490.13	310.10	11.26
2006	323.75	304.48	147.18	16.46	472.24	313.68	9.23
2007	332.43	302.46	147.18	0.52	436.82	339.54	11.32
2008	320.12	324.34	147.18	0.02	437.38	348.99	12.97
2009	332.27	326.18	147.18	12.13	473.30	341.93	12.30
2010	350.00	298.31	147.18	12.76	469.21	333.48	10.69
2011	318.62	302.53	147.18	11.14	461.56	312.45	11.79

[a] Includes both fixed and variable OM costs.

2.6 Combined-Cycle Gas Turbines

Combined-cycle gas turbines (CCGT) are composed of multiple thermodynamic cycles that work together to produce power and/or heat from the same source of fuel. In particular, heat engines work in tandem to convert thermal heat from the same fuel (typically natural gas) into mechanical energy which then drives electrical generators. In a typical configuration for a power plant, the first cycle or heat engine, is a gas turbine which burns natural gas to produce heat, the exhaust steam from the first process is sent to a steam cycle which can either be configured to produce additional power or to generate heat. All of the combined-cycle gas turbines in Denmark are combined heat and power plants.

The main advantage of CCGT over single-cycle turbines is the increase in thermal efficiency. Although, there exists a tradeoff because CCGTs generally burn natural gas and/or gas oil which are more costly relative to other fuels like coal for example. In general, natural gas fired combined-cycle turbines are characterized by high electricity efficiencies and relatively short and less costly ramp-up times. In addition, CCGT are capable of operating part load although at reduced electricity efficiency. Because CCGT plants can be started relatively quickly and do not have to run near full capacity, they are particularly suited to serving peak demand periods or serve as backup capacity.

In figure 2.20, we report the amount of electricity generated by these CCG as well as their share of aggregate generation. These data are quite interesting. From at least 1998 to 2004 the amount of electricity generated in Denmark by combined-cycle generators had been increasing. In fact, between 1998 and 2002, the amount of electricity generated by these plants more than doubled. This large increase in generation observed during these four years corresponded with the commissioning of a large CHP CCGT in 2001. This new generator had an electricity generation capacity of 568 MW and a thermal capacity of 1162 MW. This new addition to the Danish power system was substantial: The addition of this generator doubled the aggregate capacity of combined-cycle generators from approximately 510 MW to 1078 MW.

As the amount of electricity generated by the combined-cycle generators increased, so did their share of

Figure 2.20: Aggregate Electricity Delivered, Combined-Cycle Gas Turbines, 1998-2011

aggregate generation. Their share increased from less than five percent to over 11 percent by 2011. However, after 2004 there was a slight decreasing trend in both the amount of electricity CCGTs generated and in their share of aggregate generation. There was quite a bit of annual variation in both generation and share of aggregate generation after 2004. Over the entire sample period, only two generators were decommissioned, both in 2011. These were small generators each with about $7MW$ of electricity generating capacity.

2.6.1 Capital Costs

The capital costs for the CCGT are reported in figure 2.21. There is a slight downward trend in capital costs observed between 1998 and 2006 with costs declining about 28 percent. However, there was a large spike in capital costs in 2001. The large spike in capital costs was due to the low capacity rate of the large generator that was commissioned in 2001. Although the official commission date reported in the data is January 1, 2001, the generator did not generate much electricity in its first year relative to its production in the following years. The generator produced only 275 GWh of electricity in 2001 compared to over 17 hundred GWh in 2002 and 23 hundred GWh in 2003. The low capacity factor for this generator, combined with its size, drove up capital costs in 2001. Once the generator was running at normal rates, capital costs dropped back down.

The contribution capital costs made to aggregate generation costs also rose quite substantially in 2001. However, contributions to aggregate generation costs did not increase because capital costs increased, rather contributions increased because CCGT were contributing a larger share electricity to aggregate output. Comparing figure 2.20 to figure 2.21 illustrates the correlation between contributions of CCGT's capital costs to aggregate generation costs and their share of aggregate electricity generation.

Capital costs started to creep back up after 2006 so that by 2011 average cost of capital was nearly at the same level as observed in 1998. The increase in the cost of capital observed after 2006 was due to the decrease in capacity rates. As we illustrate in figure 2.22, capacity rates peaked in 2004, when the average capacity rate was approximately 46 percent, and then decreased steadily until 2009. The average capacity rate in 2011 was

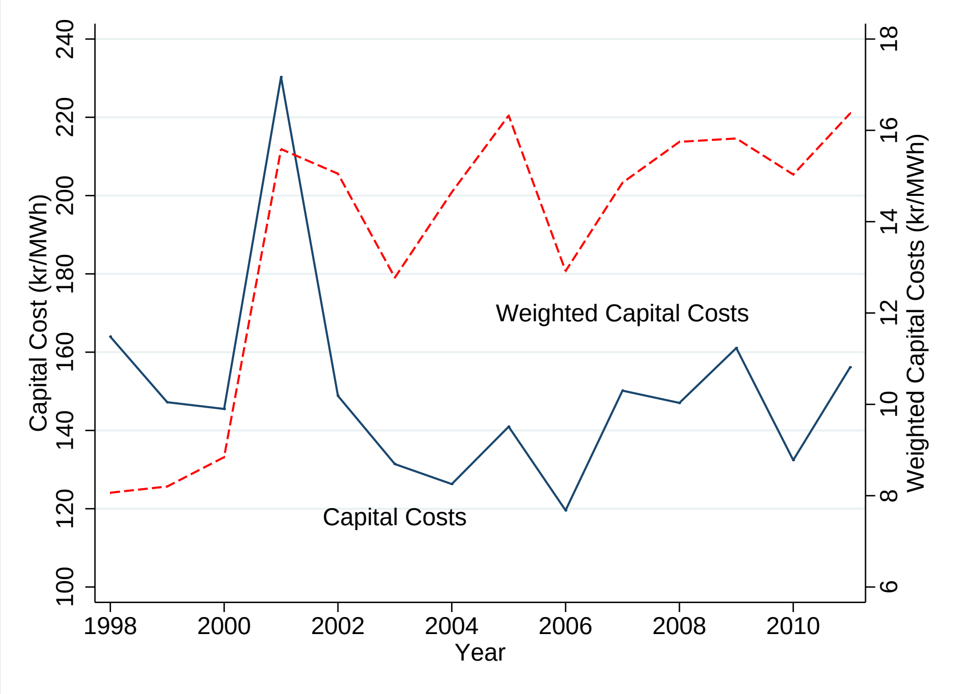

Figure 2.21: Capital Costs, Combined-Cycle Gas Turbines, 1998-2011

the lowest over the entire sample period. At the beginning of the sample period, rates were actually increasing even after the addition of over 500 MW of capacity in 2011.

Capital costs are also reported in table 2.7. In our calculations we assumed that the maximum lifetime of a CCGT was 35 years unless the turbine was decolourised during the sample period. For decommissioned plants we used the actual lifetime of the generator. The average age of the CCGTs was 12 years (18 years in 2011). We assumed an overnight cost of $kr7.1M_{2011}/MW$ for each generator.

2.6.2 Fuel Costs

Combined-cycle gas turbines primarily burned natural gas during the sample period. However, we illustrate in figure 2.23 that a variety of other fuel was also used. Natural gas was the dominant fuel, but its share was declining since at least 1999. There were two important cases of interfuel substitution. First, the initial decline in the share of natural gas was due to substituting fuel oil for natural gas. Between 2000 and 2003 the share of fuel oil increased from essentially zero to over 20 percent by 2003, while over the same period, the share of natural gas decreased from 84 percent to 58 percent. The second case involves the rise of wood pellets as a fuel. Wood pellets began being used as a fuel in 2001 and by the end of 2011, woods pellets accounted for over 30 percent of the fuel used used by CCGTs. Examining the data for the individual generators indicates that wood pellets essentially replaced fuel oil. Waste was also consistently used over the sample period.

In figure 2.24, we show that even with the interfuel substitution observed over they years with fuel oil and wood pellets, thermal efficiency did not change very much ranging from a minimum of 0.39 to a maximum of 0.42. Therefore, the variation and trends in the burner-tip costs observed in the same figure were caused by fluctuation in prices and changes in fuel shares. In general, burner-tip costs were increasing from 1998 to 2008. Most of the increase was caused by the increase in the price of natural gas. The substitution away from fuel oil which started in 2006, was likely do to the sharp increases in the price of fuel oil which started in 2005. The peak observed in 2008 was due to the fact that all fuel prices spiked in 2008. The burner-tip costs are also

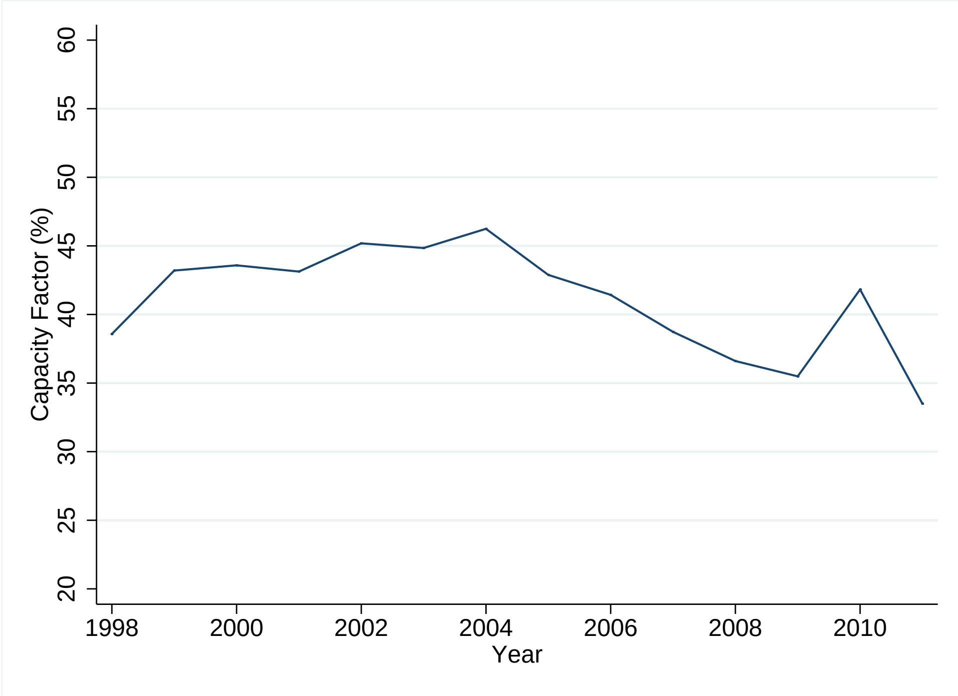

Figure 2.22: Capacity Factor for Combined-Cycle Gas Turbines, 1998-2011

reported in table 2.7.

2.6.3 Operation and Maintenance Costs

Fixed operation and maintenance costs were assumed to be $kr20.07_{2011}/MWh$. Variable operation and maintenance costs were assumed to be $kr6.86_{2011}/MWh$. Therefore, aggregate operation and maintenance costs equal $kr26.92_{2011}/MWh$. Annual average costs are reported in table 2.7.

2.6.4 Emissions Costs

The cost of carbon emissions ranged from $kr0.03_{2011}/MWh$ to a high of $kr28_{2011}/MWh$. Emissions costs are lower for combined-cycle gas turbines relative to coal fired generators because burning natural gas emits less carbon relative to coal. Annual average costs are reported in table 2.7.

2.6.5 Heat Credits

The combined-cycle gas turbines operating in Denmark generate electricity as well as heat. The average heat credit applied to the combined-cycle gas turbines was $kr276.31_{2011}/MWh$. The maximum credit was $kr237.66_{2011}/MWh$ and the minimum was $kr237.66_{2011}/MWh$. Recall that heat credits were determined by the levelised costs of a hypothetical replacement generator. So, the same factors that effect the costs of the actual generators also effect the costs of the replacement generator. Heat credits vary from year to year depending on, for example, the costs of fuel. Annual average heat credits are reported in table 2.7.

2.6.6 Aggregate Costs

The average annual cost of each component of the levelised costs of combined-cycle turbines are reported in table 2.7. The main standout of the figures presented in the table is the sharp increase in the contribution of combined-

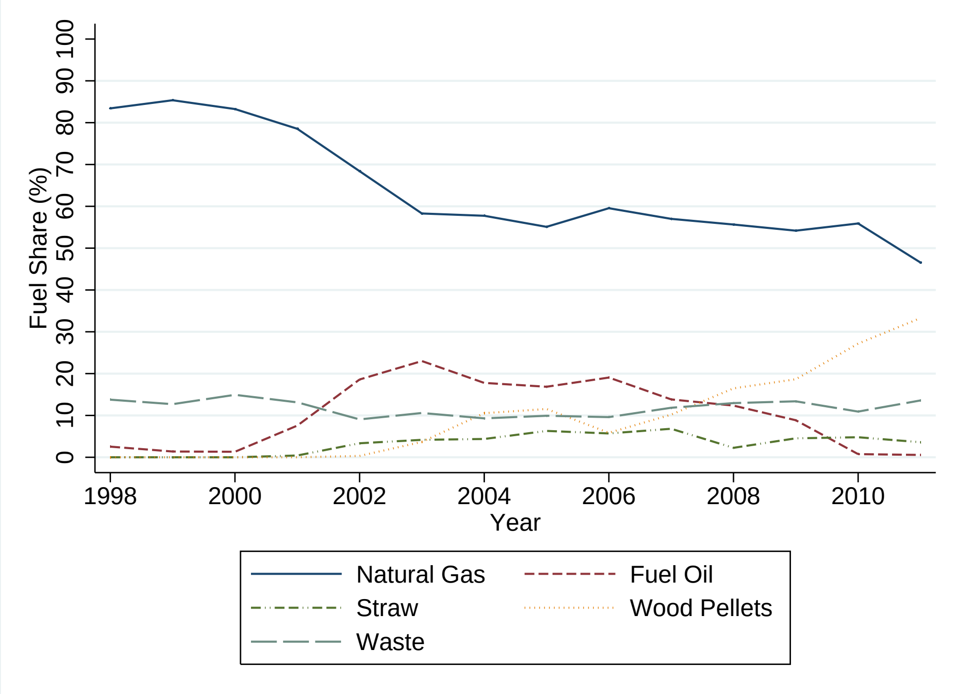

Figure 2.23: Fuels Used by Combined-Cycle Gas Turbines, 1998-2011

cycle gas turbines to aggregate generation costs. In 1998, these generators contributed just $kr16_{2011}/MWh$; however, by the end of 2011, their contribution more than doubled to over $kr40_{2011}/MWh$. This increase on their share of aggregate costs was not the result of increasing generation costs, but rather because their share of production increased. Of course, their share of costs were still small relative to the back pressure and extraction steam turbines.

2.7 Single-Cycle Gas Turbines

Gas turbines are a type of internal combustion engine in which burning of an air-fuel mixture produces hot gases that spin a turbine to produce power. It is the production of heat gases during fuel combustion, not the fuel itself that gives gas turbines their name. Gas turbines typically burn natural gas; however, other fuels can be used including liquid petroleum gas (LPG, also referred to as propane), biogas and refinery gas. Some turbines can be configured to burn both gas and oil.

Gas turbines differ from combined-cycle gas turbines (studied in the previous section) in a significant way. The thermal efficiency of a gas turbine is around 30 percent (even efficient designs are limited to 40 percent). A large amount of heat remains in the exhaust gas at it leaves the turbine. Combined-cycle gas turbines recover this exhaust heat to produce either more power and/or heat which increases the efficiency of gas turbines to around 60 percent.

In Denmark, gas turbines exist in CHP configurations or are configured to generate only electricity. The vast majority of gas turbines in Denmark are configured to produce both power and heat. The heat from the exhaust gas is either used for producing hot water which is then used for heating purposes, or as steam which is used in various production processes. In general, the large capacity turbines are configured to produce heat and power. Although, there are a small scale generators that produced both power and heat.

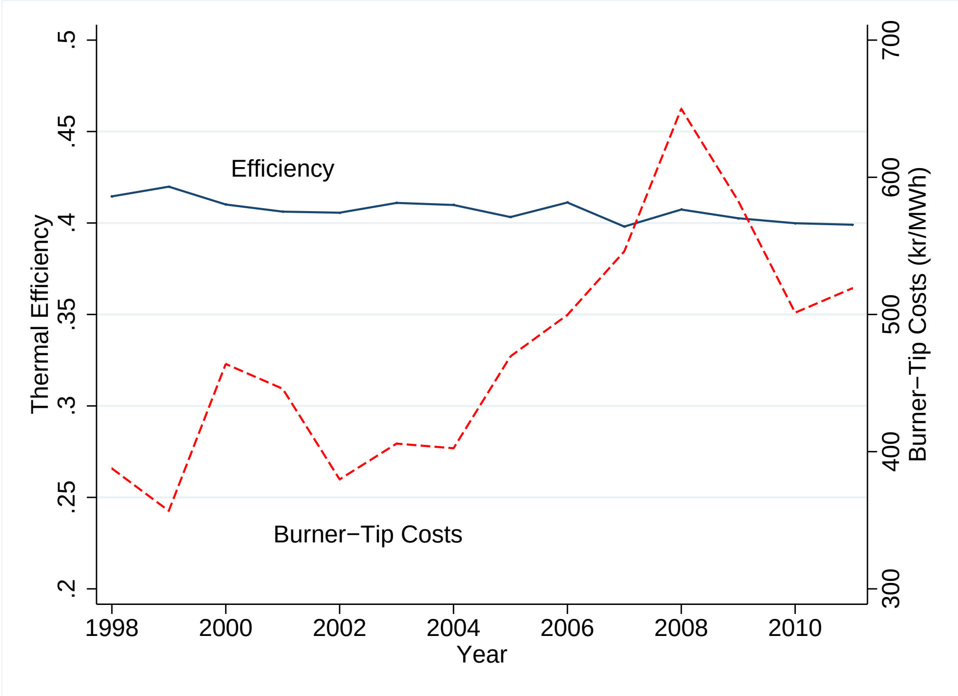

Figure 2.24: Burner Tip Costs and Thermal Efficiency, Combined-Cycle Gas Turbines, 1998-2011

One of the main advantages of gas turbines their quick ramp up times. Single-cycle gas turbines can be turned on and off within minutes. These short ramp-up times make these generators well suited to supply power during peak demand periods and act as backup capacity. In fact, because single-cycle gas turbines are less efficient than their combined-cycle counterpart, they are typically used as peaking power plants. In addition, similar to the combined-cycle gas turbines, single-cycle gas turbines are also able to operate part load.

Single-cycle gas turbines makeup a small part of Danish aggregate electricity production and their share of aggregate production has been declining since at least 1999. As of 2011, single-cycle gas turbines generated less than 2.5 percent of aggregate generation. Similarly, the amount of electricity produced by single-cycle gas turbines has declined from a high of over 15 hundred GWh in 2004, to less then 800 GWh in 2011.

2.7.1 Capital Costs

Capital costs are reported in figure 2.26. Between 1999 and 2004, capital costs remind relatively steady at around $kr500_{2011}/MWh$. After 2004, capital costs began to increase so that by 2011, costs were just under $kr900_{2011}/MWh$: An increase of over 90 percent. The increase in capital costs was strongly correlated with the decrease in electricity generation observed in figure 2.25. Moreover, we demonstrate in figure 2.26 that the decrease in production translated into substantial decreases in capacity factors. Capacity factors were declining since at least 1999, but the rate of decline increased noticeably after 2005. Between 2005 and 2011 capacity factors declined by 42 percent.

There were new investments in gas turbines in 2004 and 2005 as well as decommissioning even though production was declining only six gas turbines were scrapped between 1999 and 2011. These turbines were small and their decommissioning resulted in removing 21 MW of capacity from the power system. However, there were two gas turbines installed in 2004 and 2006 each having around 23 MW of electricity capacity. Overall, there was a net addition of 22 MW of capacity. In general, decolourising older plants had not effect on capacity factors. Interestingly, one of the new gas turbines operated with an average capacity factor of

Table 2.7: Aggregate Costs, Combined Cycle, 1998-2011 (kr/MWh)

Year	Capital Cost	Fuel Cost	Operation and Maintenance Cost[a]	Emission Cost	Heat Credits	Total Cost	Contribution to Agg. Cost
1998	163.96	387.79	26.92	NA	259.79	318.89	15.69
1999	147.21	356.86	26.92	NA	244.72	286.28	15.95
2000	145.50	463.93	26.92	NA	263.97	372.39	22.63
2001	230.31	445.86	26.92	NA	268.91	434.18	29.39
2002	148.84	379.82	26.92	NA	238.00	317.58	32.11
2003	131.42	405.89	26.92	NA	237.66	326.57	31.75
2004	126.30	402.48	26.92	NA	253.74	301.96	35.01
2005	140.97	469.46	26.92	27.59	310.30	354.65	41.07
2006	119.59	499.70	26.92	25.02	300.02	371.21	40.10
2007	150.18	546.00	26.92	0.71	262.71	461.10	45.61
2008	147.04	649.95	26.92	0.03	288.03	535.92	57.40
2009	161.06	582.77	26.92	14.30	303.26	481.79	47.33
2010	132.42	501.30	26.92	13.29	317.26	356.67	40.49
2011	156.15	519.07	26.92	10.04	323.15	389.03	40.79

[a] Includes both fixed and variable OM costs.

approximately 70 percent.

We assigned overnight costs to each turbine based on the type of plant and capacity. The overnight costs for the large-scale central CHP were assumed to be $kr26.5M_{2011}/MWh$. For the midsize decentralized turbines, we assumed an overnight cost of $kr11.8M_{2011}/MWh$. For turbines that only produced electricity, we assumed an overnight cost of $kr6.5M_{2011}/MWh$. We assumed a maximum lifetime of 45 years for those generators that were not scrapped between 1999 and 2011 to levelise the investment costs. For those turbines that were decolourised, we used each turbine's actual lifetime. The average lifetime is 38 years. The average age of the turbines in 2011 was 20 years.

2.7.2 Fuel Costs

Single-cycle turbines primarily burn natural gas with some turbines using relatively small amounts of refinery gas. Natural gas accounts for around 85 percent of the fuel used by single-cycle turbines with the remaining 15 percent is refinery gas. There was very little change in these shares overtime.

The burner-tip costs for single-cycle turbines are illustrated in figure 2.28. There was very little change in thermal efficiencies. The burner-tip costs were increasing over the period due to increasing natural gas prices.

2.7.3 Operation and Maintenance Costs

Fixed operation and maintenance costs for the large centralized turbines were $kr121.16_{2011}/MWh$ and their variable operation and maintenance costs were assumed to be $kr3.21_{2011}/MWh$. The fixed operation and maintenance costs for the smaller scale plants were assumed to be $kr53.8_{2011}/MWh$ whereas the variable costs were assumed to be $kr27.7_{2011}/MWh$. The average total operation and maintenance costs were $kr105.52_{2011}/MWh$. Total operation and maintenance costs are reported in table 2.8.

2.7.4 Emissions Costs

The cost of emissions ranged from a low of $kr0.03_{2011}/MWh$ when carbon prices were very close to zero, to a high of $kr33.42_{2011}/MWh$. The average cost of emissions was $kr17.75_{2011}/MWh$. In general, gas turbines

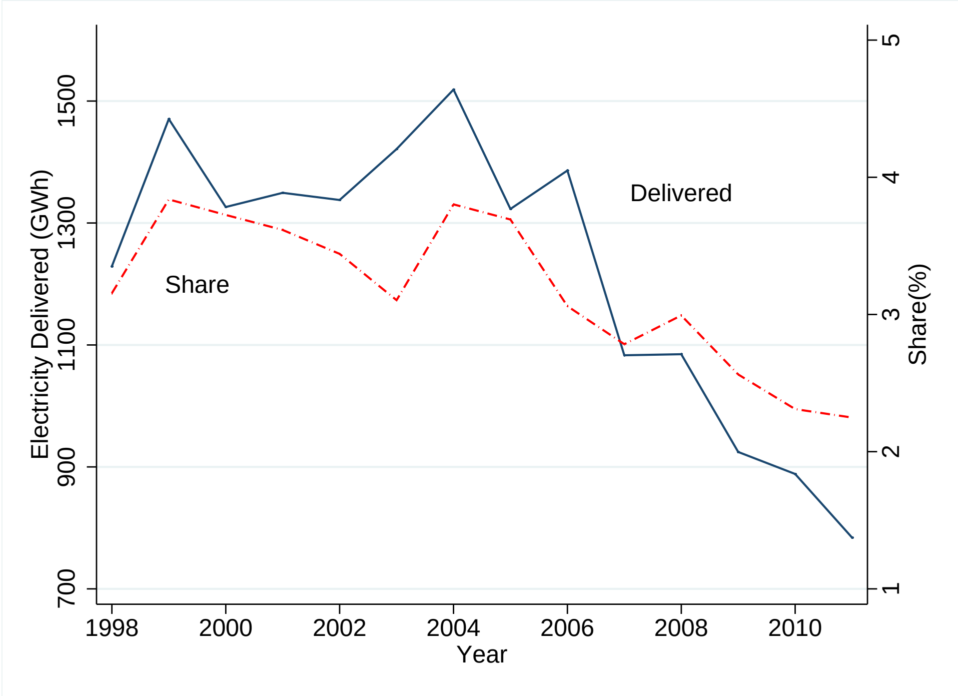

Figure 2.25: Aggregate Electricity Delivered, Single-Cycle Gas Turbines, 1998-2011

burning natural gas have lower emission costs than coal-fired generators because natural gas is a cleaner burning fuel relative to coal. Annual average emission costs are reported in table 2.8.

2.7.5 Heat Credits

The majority of single-cycle turbines produce both power and heat. We calculated heat credits for those turbines that produced heat as well as electricity. Again, heat credits were determined by the vintage and thermal capacity of each turbine. The average heat credit applied to single-cycle turbines (conditional on actually receiving a credit) was $kr278.71_{2011}/MWh$. Credits for individual turbines ranged from zero to $kr415.75_{2011}/MWh$. Annual average heat credits are reported in table 2.8.

2.7.6 Aggregate Costs

In table 2.8, we report the average annual costs for single-cycle gas turbines. Recall that in the last column we report the contribution of single-cycle gas turbines to overall electricity generation costs. The aggregate costs of generating electricity from single-cycle gas turbines has increased over the period. From 1999 to 2011 costs increased by 68 percent. The increase in costs can mostly be attributed to increasing capital costs which in turn increased because of declining capacity factors. Increasing natural gas prices also played a role.

The increase in generation costs has not affected the single-cycle gas turbine's share of aggregate generation costs. The increase in generation costs has been offset by the reduction in production. Their share of aggregate electricity production declined over the period.

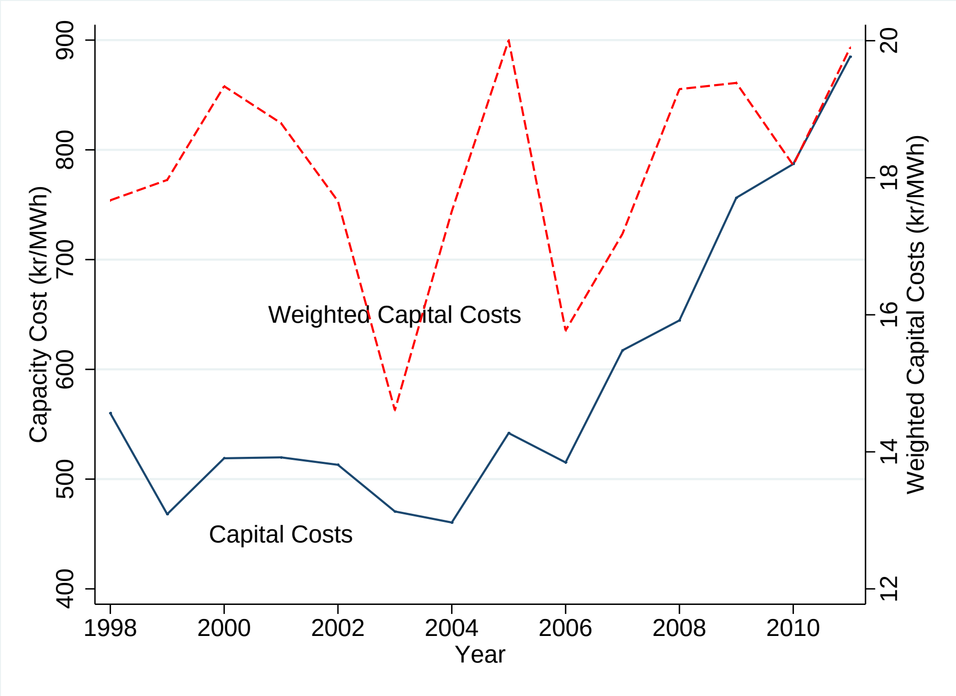

Figure 2.26: Capital Costs, Single-Cycle Gas Turbines, 1998-2011

2.8 Gas Engines

The final class of thermal generators that we study are gas engines. Gas engines are internal combustion engines. They differ from gas turbines in that gas engines rely on spark ignition, whereas gas turbines ignite the fuel and air mixture continuously. Gas engines typically burn natural gas, but can also burn biogas, landfill gas or be configured to be multifuel. The typical capacities of gas engines are between $5kW$ and $8MW$. They can be configured to produce both electricity and heat. The heat can be used in district heating systems or used to produce low-pressure steam (waste heat has a lower temperature than gas turbines which limits the pressure at which steam can be released). Gas engines have better regulation characteristics compared to gas turbines. Gas engines have faster ramp-up times and can operate at part-load with less loss of efficiency.

The gas engines in Denmark range in capacity from $0.1MW$ to $22.5MW$. Most engines are combined heat and power producers with heat capacities ranging from $0.1MW$ to $29.2MW$. The time-series characteristics of electricity generation by gas engines is similar to gas turbines. After an initial modest increase in the amount of electricity generated, there was an abrupt decline in production beginning in 2004. In only three year, electricity generation declined by almost 36 percent. Their share of aggregate electricity production also declined from a high of almost 11 percent to a low of less than 7. The sharp dip in their share of aggregate output observed in 2003 was caused by the sharp increase in production by the large steam turbines. Note that the amount of electricity generated did not change that much in 2003. Even after the steep decline, gas engines still produced between 7 and 8 percent of aggregate electricity generated in Denmark until at least 2011.

2.8.1 Capital Costs

The annual average levelised capital costs for gas engines are reported in figure 2.30. Capital costs remained relatively unchanged between 1998 and 2004. However, after 2004, there was a sharp increase in capital costs. In only two years, costs jumped by over 56 percent, from just over $kr233_{2011}/MWh$ to $kr365_{2011}/MWh$. The primary reason for the jump was the drop in capacity utilization rates, which is illustrated in figure 2.31.

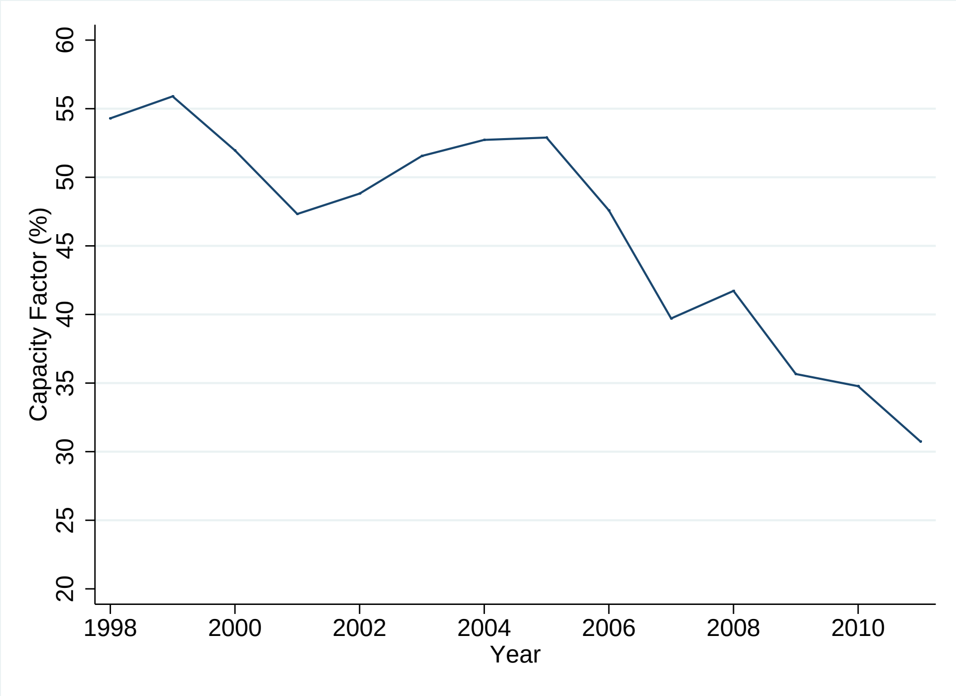

Figure 2.27: Capacity Factor, Single-Cycle Gas Turbines, 1998-2011

Although capacity factors have been declining since at least 1998, there was an increase in the rate of decline in 2005. In 1998, the average capacity factor was just over 46 percent; however, by 2011, the average capacity factor was around 27 percent.

Interestingly, the average contribution to aggregate generation costs had actually increased over the period even though the gas engines' share of aggregate generation in Denmark had been decreasing. There were large annual variations, but the overall change was quite modest. The increase in the average contribution to aggregate costs had increased because the drop in the gas engines' share of aggregate generation did not entirely offset the 56 percent increase in capital costs. The two large drops in average contributions observed in 2003 and 2006 were due to the dips in the share of electricity generated by gas engines. Recall from the discussion of coal-fired generators (condensing, back pressure and extraction) that there were spikes in production in 2003 and 2006.

We assumed that the overnight cost of gas engines were $kr10.3M_{2011}/MWh$. There was a very large range in the age of these generators. The age of active gas engines, as of 2011, ranged between two and 55 years. Moreover, there was quite a bit of variation in the lifetime observed for scrapped generators. The maximum lifetime observed for generators that were scrapped between 1998 and 2011 was 22 years, with the youngest being only 2 years old. Given the range of ages and observed lifetimes, it was difficult to determine the expected lifetime of gas engines. The technology manuals suggest a lifetime of 25 years (see Danish Energy Agency (2005) and Danish Energy Agency (2012b)). We assumed a lifetime of 30 years for those generators that were still producing electricity in 2011. We used the actual lifetime of those generators that were scrapped between 1998 and 2011.

2.8.2 Fuel Costs

Gas engines primarily burned two types of fuel: natural gas and biogas. Between 1998 and 2011, natural gas accounted for more than 80 percent of the fuel used by gas engines. Up until 2005, more the 90 percent of the

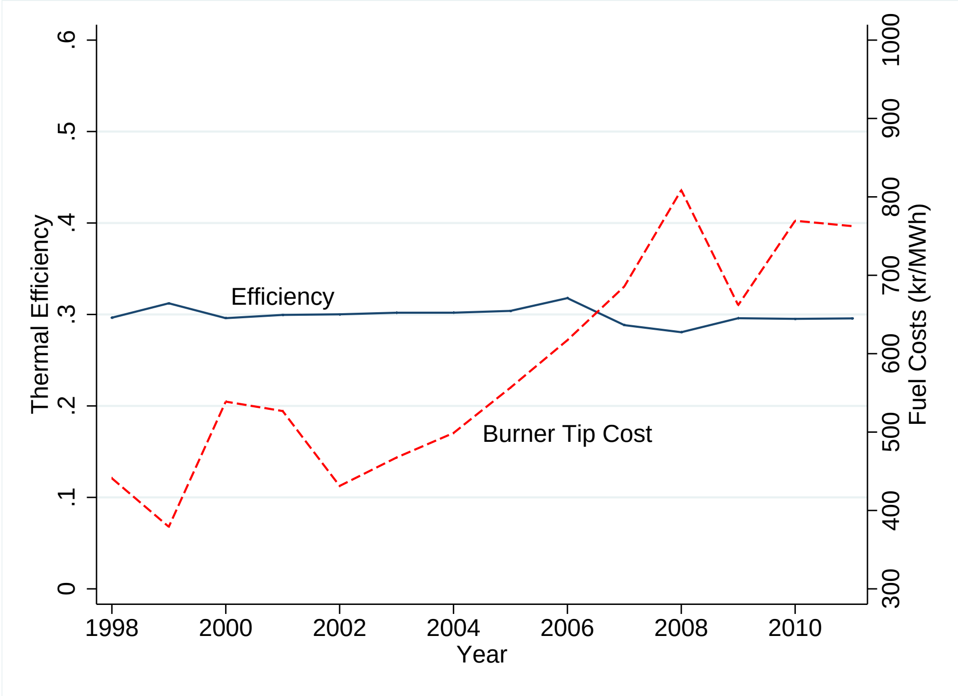

Figure 2.28: Burner Tip Costs and Thermal Efficiency, Single-Cycle Gas Turbines, 1998-2011

fuel was natural gas. However, the use of biogas has been increasing since at least 1998. By the end of 2011, biogas accounted for 15 percent of the fuel used by gas engines, an increase of about 200 percent since 1998.

The burner-tip costs were increasing over the entire sample period because natural gas prices were increasing. The gradual adoption of more biogas did not effect aver thermal efficiencies of the gas engines: The average annual thermal efficiency ranged between 36 percent and 38 percent.

2.8.3 Operation and Maintenance Costs

We assumed that fixed operation and maintenance costs were $kr8.80_{2011}/MWh$, whereas variable operation and maintenance costs were assumed to be $kr38.54_{2011}/MWh$. So, total operation and maintenance costs were assumed to be $kr47.34_{2011}/MWh$.

2.8.4 Emissions Costs

Emissions costs ranged between $kr0.03_{2011}/MWh$ and $kr32.37_{2011}/MWh$ depending on the price of carbon. The average cost was $kr17.02_{2011}/MWh$. The average annual costs are reported in table 2.9.

2.8.5 Heat Credits

The average annual heat credit applied to those gas engines which produced both heat and power are reported in table 2.9. Heat credits applied to specific generators ranged between $kr130.03_{2011}/MWh$ and $kr355.25_{2011}/MWh$.

2.8.6 Aggregate Costs

Aggregate levelised cost for gas engines increased over the period under study. Average annual costs ranged from a low of $kr395_{2011}/MWh$ in 1999 to $kr738_{2011}/MWh$ in 2011 an increase of over 86 percent. Increases in

Table 2.8: Aggregate Costs, Gas Turbine, 1998-2011 (kr/MWh)

Year	Capital Cost	Fuel Cost	Operation and Maintenance Cost[a]	Emission Cost	Heat Credit	Total Cost	Contribution to Agg. Cost
1998	560.07	441.10	103.93	NA	246.78	858.32	27.08
1999	468.08	379.21	105.98	NA	236.86	716.41	27.50
2000	519.01	538.83	105.25	NA	256.20	906.89	33.79
2001	519.82	526.83	106.30	NA	268.49	884.46	31.98
2002	513.03	431.30	104.24	NA	246.54	802.03	27.60
2003	470.55	467.57	104.98	NA	251.01	792.09	24.59
2004	460.49	498.83	107.08	NA	261.36	805.03	30.61
2005	541.92	556.66	106.86	33.42	312.36	926.51	34.21
2006	515.21	617.24	107.65	27.62	310.21	957.50	29.31
2007	617.33	685.74	103.71	0.88	279.52	1128.14	31.40
2008	644.59	808.63	105.35	0.03	295.83	1262.77	37.80
2009	756.36	661.92	104.60	19.85	303.45	1239.29	31.76
2010	787.08	769.56	106.39	21.73	322.86	1361.90	31.47
2011	884.83	762.70	105.05	18.90	330.00	1441.49	32.42

[a] Includes both fixed and variable OM costs.

Table 2.9: Aggregate Costs, Gas Engines, 1998-2011 (kr/MWh)

Year	Capital Cost	Fuel Cost	Operation and Maintenance Cost[a]	Emission Cost	Heat Credit	Total Cost	Contribution to Agg. Cost
1998	205.69	331.62	47.34	NA	174.94	407.76	40.44
1999	210.59	301.49	47.34	NA	162.61	395.11	40.05
2000	226.59	407.66	47.34	NA	202.99	476.86	50.26
2001	215.36	396.84	47.34	NA	200.18	457.54	49.20
2002	220.36	331.68	47.34	NA	175.35	422.71	43.93
2003	221.66	357.38	47.34	NA	187.27	437.85	38.39
2004	214.48	371.20	47.34	NA	193.68	437.89	44.67
2005	233.29	415.66	47.34	32.37	244.16	483.02	50.74
2006	271.59	484.98	47.34	26.74	261.45	567.70	41.25
2007	365.17	485.21	47.34	0.86	235.43	661.80	45.64
2008	364.15	534.64	47.34	0.03	255.98	688.73	52.31
2009	412.82	484.14	47.34	19.31	252.84	709.46	48.22
2010	340.66	542.93	47.34	21.04	281.25	669.23	51.44
2011	399.31	553.94	47.34	18.29	279.22	738.10	51.47

[a] Includes both fixed and variable OM costs.

both burner-tip costs of fuel and capital costs contributed to the increase in costs. The gas engines' share of aggregate costs ranged between $kr40_{2011}/MWh$ and $kr52_{2011}/MWh$. Their share of aggregate costs were a bit higher in the later years relative to the earlier years. However, even in the earlier years the share of aggregate costs reached $kr50_{2011}/MWh$. So, even though the gas engines' share of aggregate output was declining in the later year, their overall share of aggregate costs did not fall because their production costs increased.

Figure 2.29: Aggregate Electricity Delivered, Gas Engines, 1998-2011

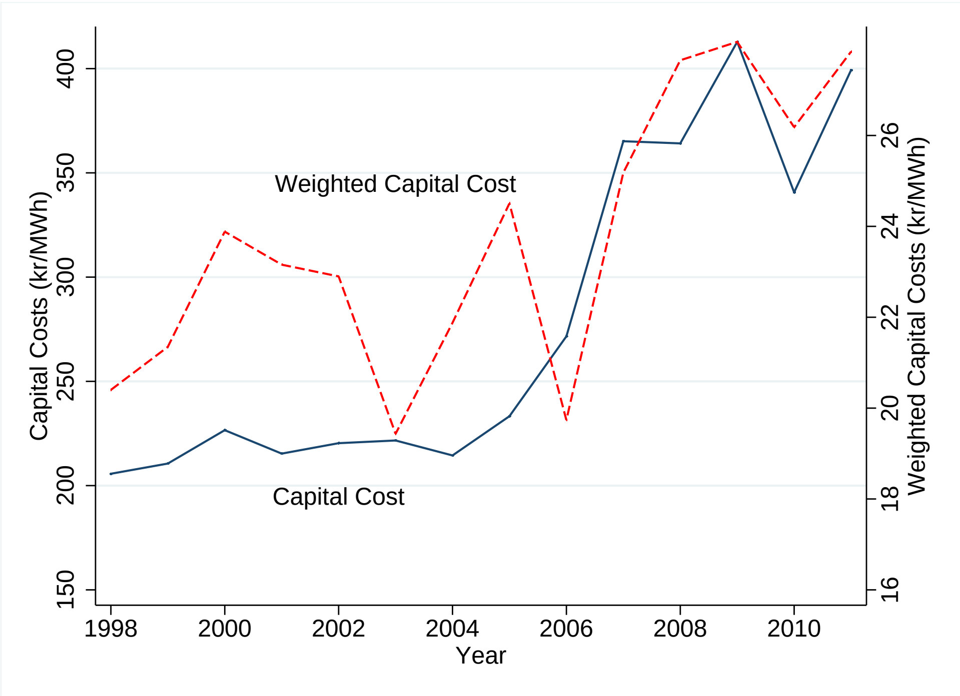

Figure 2.30: Capital Costs, Gas Engines, 1998-2011

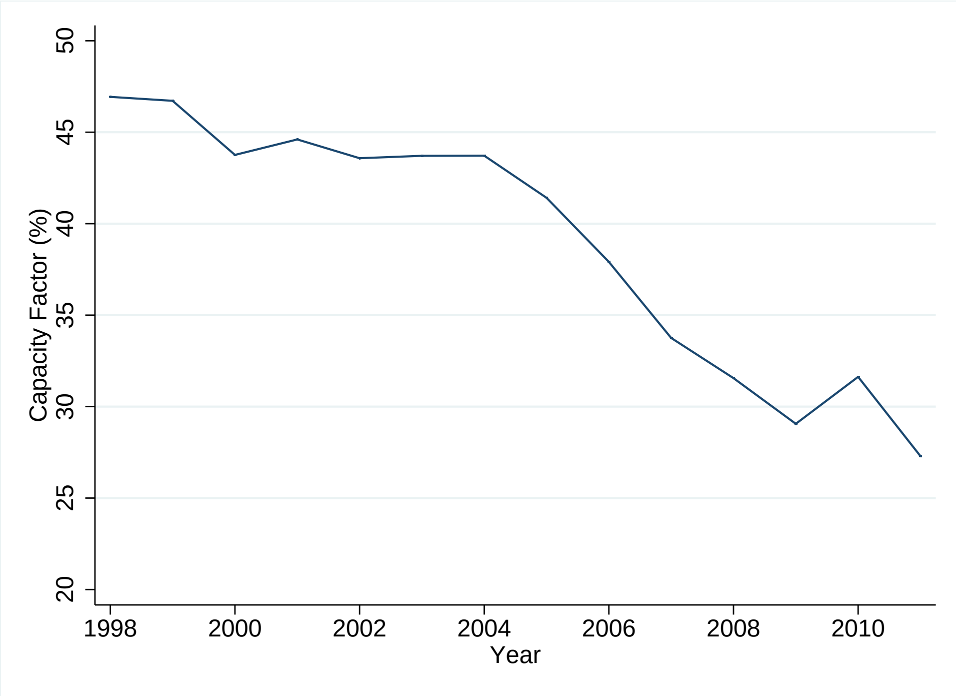

Figure 2.31: Capacity Factor, Gas Engines, 1998-2011

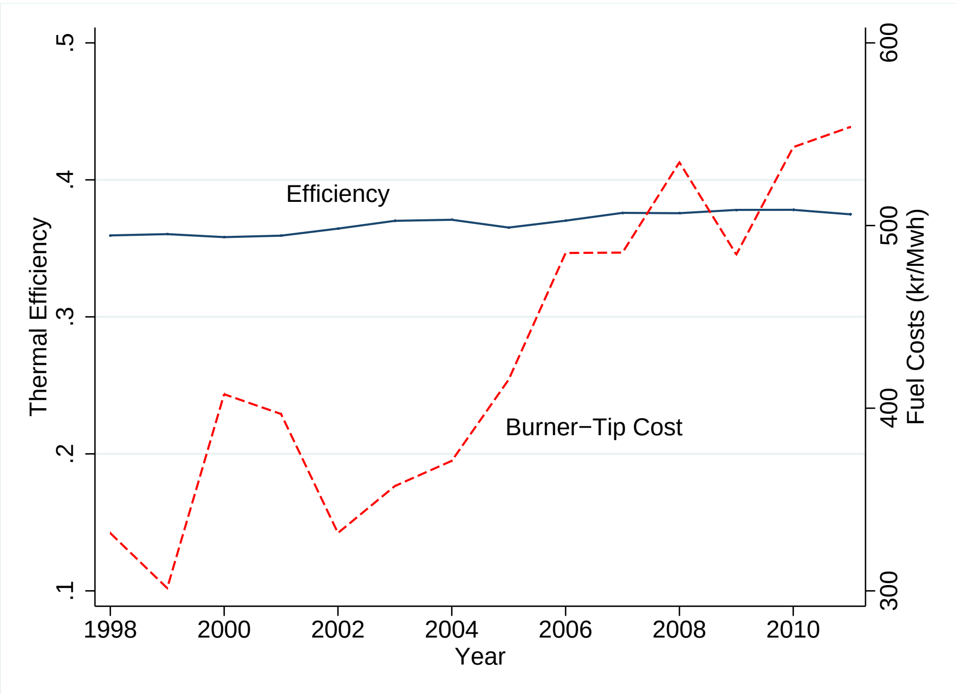

Figure 2.32: Burner Tip Costs and Thermal Efficiency, Gas Engines, 1998-2011

Chapter 3

Non-Thermal Generation in Denmark

3.1 Introduction

Non-thermal sources of power are becoming increasingly important in the Danish power system. The most recognizable source, and indeed the most important source, of non-thermal generation in Denmark is from wind. Denmark has been an international leader in integrating wind generation into its national power system. The result is that wind power has become an integral source of electricity within the Danish power system. There were $5,130$ turbines generating power in 2011 with an aggregate installed capacity of about $4,005MW$. These wind turbines generated approximately 28 percent of all the electricity produced in Denmark in 2011.

Wind energy will continue to grow as a source of power in the foreseeable future as Denmark pursues an aggressive renewable energy policy. The Danish government developed a new energy agreement in 2012 (2012 Energy Agreement) in which the core policy objective is a full conversion to renewable energy by 2050. An expansion of wind energy is an important part of this renewable energy policy.[1] The 2012 Energy Agreement includes an initial target of installing $1,000MW$ of new offshore wind capacity by 2020 and a proposal to install $1,800MW$ of new onshore capacity while decommissioning old onshore capacity.

There are two other minor sources of non-thermal power: hydro and solar. Hydro and solar have not generated a significant amount of electricity in the past. Although the amount of electricity generated from solar has been increasing over the last few years and could become an important part of the Danish power system in the future. The 2012 Energy Agreement discusses the long term goal of developing alternative renewable technologies and integrating these technologies into the Danish Power system (see Danish Minsitry of Climate, Energy and Building (2012)). Two technologies that were emphasized in the agreement were solar and wave power. With intermittent sources of power, like wind, wave and solar, integrating varied sources of power into the power system is an important goal because the various sources are productive at different times and under different conditions. Varied sources of power help reduce costs associated with intermittent power sources like wind, solar and wave.

More electricity is generated from hydro sources than is generated from solar. However, electricity generated from hydro sources in Denmark has been declining for a number of years whereas solar generation has been increasing. Since 1998, the maximum amount of electricity generated annually by hydro was approximately $34GWh$ which occurred in 1999. The lowest amount was observed in 2011 and was less than $18GWh$–almost half the amount generated in 1999. Moreover, hydro is not expected to be a vital source of power in the future. Indeed, there is no mention of reinvesting in updating existing plants or investing in new hydro stations in the

[1] For an overview of the new energy agreement see Danish Minsitry of Climate, Energy and Building (2012). As part of new agreement, there will a significant increase in investments in renewable energy of around $kr90 - 150$ billion up to 2020.

2012 Energy Agreement.

The significant role of wind turbines in the Danish power system combined with the continued focus of Danish electricity policy on increasing wind penetration rates in the Danish power system suggests a need to understand the costs of the electricity produced by Danish wind turbines. This chapter provides a study of the cost of generating wind energy in Denmark. In particular, costs are calculated for offshore and onshore turbines and their costs are tracked over time. In addition, because solar could become an important part of the Danish power system in the future a brief description of the state solar generation is provided. Finally, a short description of hydro generation is also provided.

3.2 Wind Turbines

There has been a substantial increase, since at least 1985, in the number of wind turbines supplying electricity to the Danish power system. There were just over 820 turbines generating electricity in 1985 with a total installed capacity of approximately $47MW$. All of these turbines were land-based. By the end of 2011, there were $5,130$ turbines, both onshore and offshore, generating electricity. Coinciding with the growth of wind generation was the general maturing of turbine technology resulting in changes to certain characteristics of turbines. An obvious attribute of turbines that has changed over time has been their size. The early turbines were substantially smaller than those installed more recently. The average rotor size of a turbine operating in 1985 was 12 metres (the maximum diameter was 400 metres) with an average capacity of $54kW$. Turbines operating in 2011 had an average installed capacity of over $780kW$ with a rotor diameter of approximately 45 metres. There has been a steady increase in both the number and size of turbines since 1985.

Rotor size and installed-capacity is one important characteristic of turbines. Another important characteristic is location. It is important to make a distinction between between offshore turbines and land-based turbines. Offshore turbines typically cost more to construct (greater overnight costs) and have greater operating costs. However, on average, offshore turbines have larger rotors and greater capacity. So, even though offshore turbines generally have larger fixed costs, it is possible for their average costs to be lower than onshore turbines if offshore turbines have larger capacities and are operating with greater capacity factors. The average capacity of an offshore turbine is $1928kw$ with a average rotor diameter of 76 metres. Land based turbines have an average rotor diameter of 30 metres and an average capacity of $372kW$.

Historically, the majority of wind turbines have been land-based (onshore). However, most of the new investments in wind energy have been targeted at offshore locations. Figure 3.1 reports the growth and mix of wind turbines since 1985. The expansion of turbines beginning in the mid 1980s peaked in 2002 with $6,680$ turbines supplying the Danish grid. Of those $6,680$, 123 turbines were located offshore and $6,557$ were located onshore. The stock of turbines has been decreasing since 2002 due to older land-based turbines being decommissioned. This has not been the experience of offshore turbines. The stock of offshore turbines has been increasing since the first was installed in the early 1990s. While the stock of onshore turbines has been decreasing since 2002, just under 300 offshore turbines were installed by 2011. This investment increased capacity by $650MW$.

The aggregate capacity of land-based turbines has actually been increasing over time even though the stock of turbines has been decreasing. Newer onshore turbines typically have larger rotors resulting in greater capacities. The increase in capacities of newer onshore turbines more than offsets the reduction in capacity through the decolourising of older onshore turbines. Capacities are reported in figure 3.2 to illustrate the evolution of capacities for onshore and offshore turbines as well as aggregate capacity. Aggregate installed capacity has

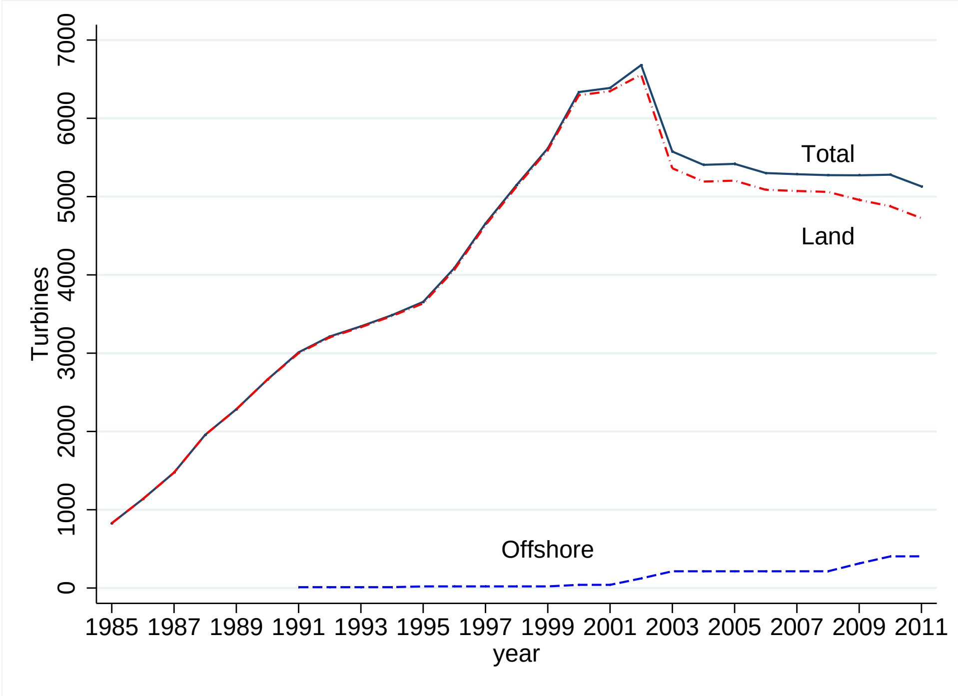

Figure 3.1: Wind Turbines, 1985-2011

been increasing for both onshore and offshore turbines since at least 1985. The overall reduction in the stock of turbines observed since 2002, combined with the increase in capacity, indicates that windmills have been getting larger with greater capacities. The economic implication of larger turbines is that the average cost of generating electricity from larger turbines could potentially be smaller than turbines with smaller capacities. Larger turbines could benefit from economies of scale. However, in order for larger turbines to benefit from economies of scale, they must be operating at a sufficiently high capacity rate. That is, the larger turbines must actually be using their installed capacity and not just sitting idle. Larger turbines are generally more costly to build and operate; therefore, the opportunity cost of an idle large-scale turbine is larger than a small-scale turbine. Capacity rates are very important for determining average costs.

Wind generation is reported in figure 3.3 to provide an overview of the amount of electricity generated by wind turbines and how generation has evolved overtime. The amount of electricity generated by wind turbines has been increasing since at least 1985 with sharp increases occurring in 1996 as well as in 2002 and 2009 when offshore generation jumped. While onshore generation has been increasing since at least 1985, offshore generation did not really make a substantial contribution until 2002. There was another jump in offshore production in 2009.

The stock of wind turbines has been decreasing since 2002 but the amount of electricity delivered by turbines has been increasing. There could be a variety of reasons for this observation. Three main reasons are first, the new turbines being installed have a larger capacity; second, the new windmills have been located in better places; and, third, technology has improved. It is clear from figure 3.2 that capacities have increased. However, additional capacity is only productive if it is actually being utilized. Turbines with large capacities but are operating with low capacity factors will not lead to greater observed electricity production. Turbines need to be placed in locations with appropriate wind speed conditions. Power cannot be generated unless the wind speed surpasses a minimum level. The minimum wind speed is called the cut-in speed and is typically around five metres per second. Power output increases at an increasing rate as wind speed increases. There is typically a maximum amount of power that a turbine can produce even if wind speeds increase. If wind speeds are too high,

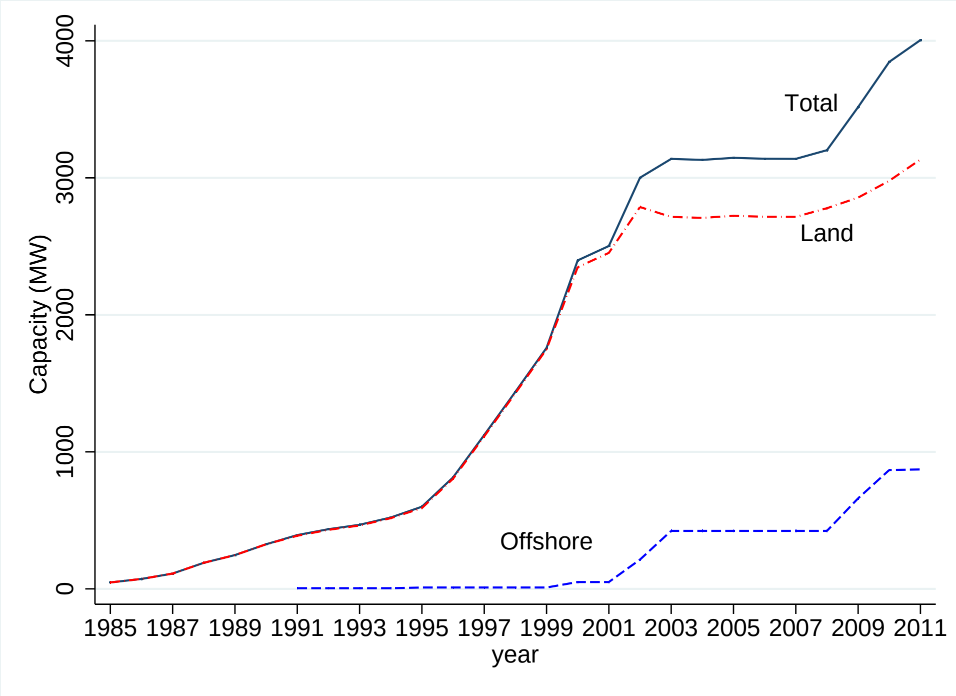

Figure 3.2: Capacity, Wind Turbines, 1985-2011

more than 25 metres per second for example, then turbines must be shutdown to avoid damage. Therefore, there are three sources of variability that affect a turbines power output. First, power cannot be generated if wind speed is below the cut-in speed. Second, between the cut-in speed and maximum output, varying wind speeds can cause large changes in output. Finally, turbines must be shutdown if wind speeds are too great. The choice of location is important because choosing a location essentially means choosing the wind speed characteristics which determine the variability of the power output of a turbine installed at that location. The characteristics of wind speed at specific locations largely determine capacity rates.

Overall, it is clear that wind generation has made significant contributions to overall load in the Danish system. Moreover, wind energy in Denmark will continue to grow. This is why contribution made by wind turbines to aggregate generation costs are important. Understanding the costs of producing electricity from wind will lead to a more comprehensive view of aggregate generation costs and how these costs have been evolving over time and how they might evolve in the near future as wind continues to expand. The costs of wind generators is studied in 3.3.

3.3 Levelised Cost of Wind Turbines

One significant difference between the factors that determine the costs of electricity generated by wind turbines and those that determine the costs of electricity generated by thermal generators is that there are no fuel costs for wind turbines. So, calculating the levelised cost of wind turbines requires calculating capital costs as well as operation and maintenance costs. The costs of generating electricity vary across wind turbines based on their characteristics. Therefore, it is necessary to account for the different characteristics that exist between wind turbines, to the extent that the data allow for, in the cost calculation. The important characteristics to consider are location, capacity and vintage. Offshore turbines are more costly relative to onshore turbines. Larger turbines typically cost more to construct and service. Finally, vintage is important because older turbines would have cost more to construct and run relative to new vintage turbines.

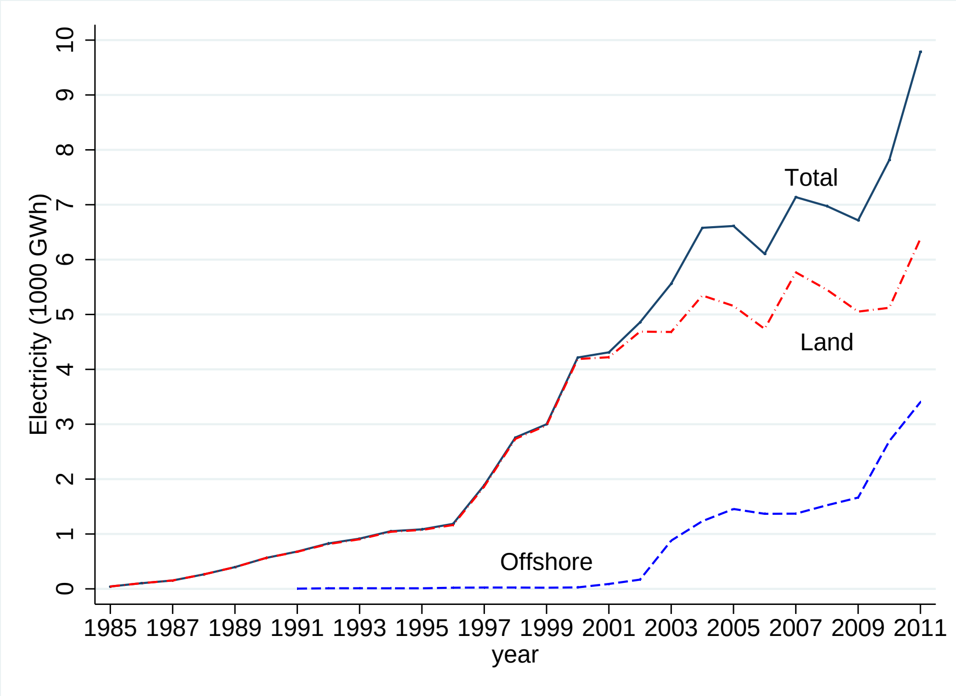

Figure 3.3: Electricity Delivered, Wind Turbines, 1985-2011

3.3.1 Capital Costs

Capital cost were assigned to each wind turbine according to their attributes and whether the turbine is located onshore or offshore. In particular, turbines were classified based on their vintage, location and capacity. In general, offshore turbines cost more than onshore turbines given vintage and capacity. Older generators typically have greater overnight costs relative to newer turbines typically because of a first-of-a-kind (FOAK) cost structure. Larger turbines generally have larger overnight costs relative to smaller capacity turbines.

As described previously, capacity factors are an important determinant of capital costs because they determine how fixed construction costs are distributed across power output. Low capacity factors result in relatively large per MWh costs because the overnight construction costs are distributed over a small amount of output. In contrast, high capacity factors result in relatively small per MWh costs because overnight construction costs are dispersed over high electricity output. Because capacity factors have a large influence on capital costs, in Figure 3.4 we present the average annual capacity factors for the stock of offshore and onshore turbines. Recall that annual capacity factors measure how much of a turbine's capacity has been used to generate electricity. Capacity factors for wind turbines were calculated directly from data using

$$cf = \frac{kWh \text{ production}_t}{kW \text{ capacity} \times 8760 \text{ hours}}. \tag{3.1}$$

In the figure are presented three series: the average annual capacity factor for all turbines, the average capacity factor for onshore turbines and the average capacity factor for offshore turbines. A number of interesting facts emerge from the data presented in the figure. Since the early 1990s, there has been little change in the aggregate long run average annual capacity factor. There were annual fluctuations in the average capacity factor, but the long run trend is fairly flat post 1991. There was a substantial increase in the average capacity factor prior to the 1990s. The average capacity factor over all turbines was approximately 20 percent and the maximum capacity factor was about 24 percent. The average capacity factor for onshore turbines matches the aggregate average capacity factor since most of the turbines were located onshore. However, in the later part of

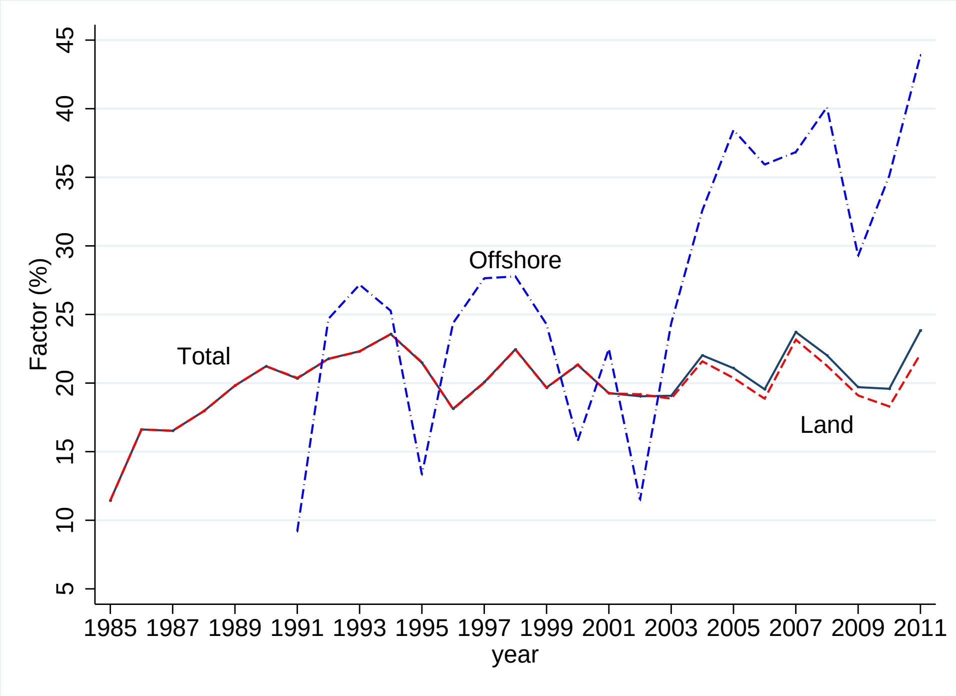

Figure 3.4: Capacity Factors, Wind Turbines, 1985-2011

the sample, the two series start to diverge as more offshore turbines, which generally had larger capacity factors, began supplying the power system. On average, offshore turbines used more of their capacity than did onshore turbines. The average capacity factor for offshore turbines was just under 34 percent with a maximum capacity factor of approximately 44 percent. There is also a large degree of variability in capacity factors for onshore turbines relative of onshore turbines. A large part of the variability observed between 1991 and 2002 was caused by a small set of turbines producing very little electricity. This small set of turbines had a large influence on average capacity factors because the stock of offshore turbines was relatively small during this period.

The overnight costs were again collected from the Balmorel model. Recall that the Balmorel model used a variety of technology manuals to construct its database of costs. The benefit of using these cost parameters is that costs can be allocated based on the characteristics of the turbines. Specifically, costs were allocated to each turbine based on location, vintage and capacity. Similar to the costs calculated in chapter 2, nominal values were converted to real Danish kroner using the same interest rates, exchange rates and producer price index that were used in chapter 2. Recall that these data are described in the the data appendix.

Construction costs for offshore turbines were assigned according to vintage. Offshore turbines installed in the early years were more costly relative to those constructed in the later years because of a first-of-a-kind cost structure. Relatively new technology combined with new construction process typically involves additional costs compared to a mature technology that is using a vetted construction process were best-practice construction management has been developed. Developing new construction techniques for new technologies as well was installing new supply chain management systems necessarily involves additional risks and costs that are not necessarily borne by mature industries and technologies. The construction costs for offshore turbines constructed prior to 2000 were $kr19.27M_{2011}/MW$. For offshore turbines constructed between 2000 and 2009, construction costs were $kr15.61M_{2011}/MW$. Offshore turbines constructed after 2009 had a construction cost of $kr13.10M_{2011}/MW$. The construction costs of offshore turbines constructed prior to 2000 cost almost six million DKK more than those constructed after 2009. Note that the construction costs we use are consistent with those reported by the Danish Energy Agency: they report an average cost of $kr15.75M_{2011}/MW$ for turbines constructed between 2002 and 2010.

The are features of wind farms that could be important for construction costs for which we cannot account for. For example, depth and distance from shore could be important determinants of construction costs.

Construction costs for onshore turbines were assigned according to size. There is not the same concern with a FOAK cost structure with onshore turbines since the industry and technology can be considered mature relative to offshore turbines. Most technology manuals, including the Danish technology manuals as well as the Balmorel energy model, do however make adjustments to construction costs based on the size of the turbines. The construction costs for onshore turbines with capacity less than $600kW$ was $kr10.03M_{2011}/MW$ and for onshore turbines with a capacity greater than $600kW$ the cost was $kr9.19M_{2011}/MW$. The difference in overnight costs is less than one million DKK. Once again, note that the construction costs we use in our calculation of capital costs are consistent with those recently reported by the Danish Energy Agency in their 2014 technology catalogue update: they report an average cost of approximately $kr9.0M_{2011}/MW$ (see Danish Energy Agency (2014)).

Capital costs were calculated using the overnight costs, the capital recovery factor and capacity factors.[2] Capital costs are presented in figure 3.6. Capital costs are reported for land-based turbines and for offshore turbines.[3] Average capital costs for both onshore and offshore turbines have been declining overtime. Although, offshore turbines experienced large spikes in costs in 2000 and 2002.[4] The observed spikes in 2000 and 2002 were caused by a collection of turbines having very low capacity factors. Post 2002, capital costs for offshore turbines tended to be much less volatile. There are two reasons for the observed decrease in volatility. First, there was less volatility in the capacity factors for offshore generators; and, second, there was an increase in the number of offshore turbines which reduced the potential influence on costs of a small group of turbines having low capacity factors. The overall trend of decreasing capital costs observed for offshore turbines was primarily due to an increases in capacity rates. This was especially true for turbines constructed post 2002. These turbines had higher capacity rates likely due to better location planning. However, older offshore turbines also tended to have higher capacity rates post 2002. A second reason for declining costs for offshore turbines was the decrease in construction costs that occurred as the industry began to mature.

Capital costs for the onshore turbines had less variation relative to offshore turbines due to more consistent capacity rates. Because the set of onshore turbines is relatively larger there is less opportunity for a small set of turbines with low capacity rates influencing costs. The long run trend in declining capital costs is primarily due to replacing old turbines with new turbines. The reduction experienced early in the series was due to increasing capacity factors. Post 1998, any reduction in costs was generally achieved through decommissioning old turbines. By 2003, offshore turbines had lower capital costs relative to onshore turbines even though overnight costs tended to be larger for onshore generators. Offshore turbines were able to achieve lower costs through higher capacity utilization rates and consistently used more of the capacity than did onshore turbines.

Average capital costs over all turbines are reported in figure 3.6. The striking feature of the data presented in the figure is the significant decrease in capital costs since 1985. There are a number of reasons for the observed reduction in costs. These were described previously, but a summary of the causes of the reduction in costs is useful. First, as the offshore turbine industry matured and develop the FOAK cost structure dissipated

[2]See Chapter 3 of Levitt and Sørensen (2014) for details. Recall that the capital recovery factor is the ratio of a constant annuity to the present value of receiving the annuity for the life of a generator. Importantly, the capital recovery factor amortizes the investment costs over the lifetime of the generator.

[3]The figure reports the annual weighted average costs for each type of turbine. The weights for offshore turbines are each offshore turbine's share of aggregate electricity generated only by offshore generators. The weights for onshore generators are each onshore turbine's share of aggregate electricity generated only by onshore generators.

[4]The initial point (1991) in the series is relatively high because the 11 offshore turbines that make up this data point had low capacity factors. The capacity factor for each turbine was less than ten percent.

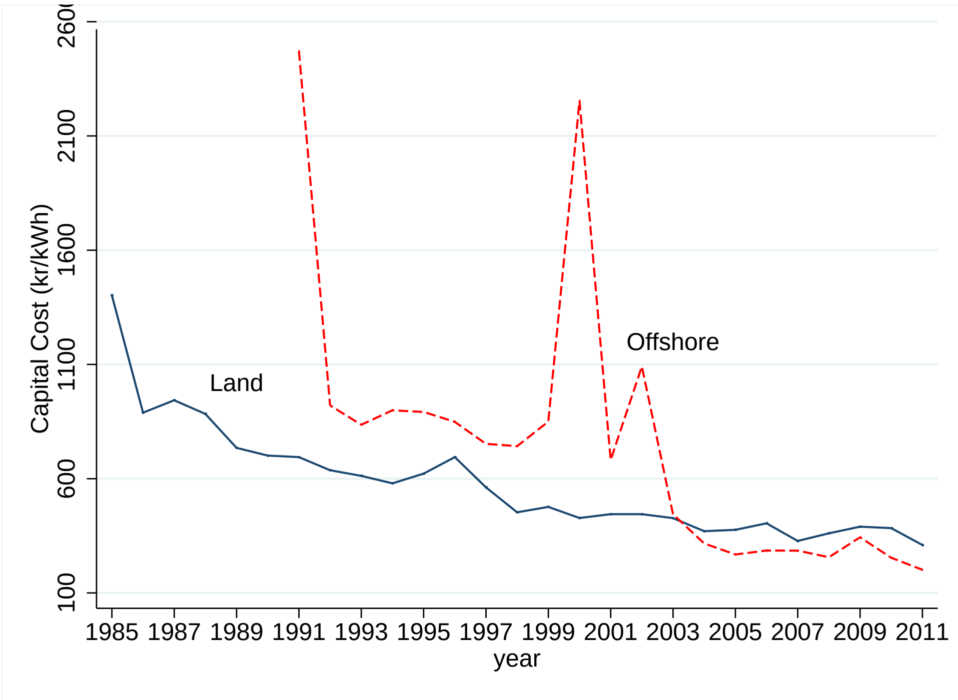

Figure 3.5: Capital Costs, Wind Turbines, 1985-2011

resulting in decreasing construction costs of relatively newer turbines. Second, new generators tended to have larger capacities creating the potential for economies of scale. That is, fixed costs can be spread over great amount of production. Third, higher capacity rates, together with larger capacities, results in lower per MWh costs. Finally, older, less efficient onshore turbines were scraped and new turbines were installed. One would also like to know what is the contribution made by the capital costs to overall production costs. The contribution made by capital costs of wind turbines is reported in Figure 3.6. The contribution is calculated as the weighted average capital costs where the weights are each turbines share of aggregate generation including thermal generation. Even though average capital costs have been decreasing since 1985, the contribution they have made to overall generation costs have been increasing. Their contribution has been increasing because the share of electricity generated by wind has been increasing. A larger share of generation results in a larger share of costs. Of course, what happens to overall costs depends on the cost of the electricity displaced by wind energy which is studied in chapter 6 of Levitt and Sørensen (2014).

3.3.2 Operation and Maintenance Costs

Similar to capital costs, operation and maintenance costs were assigned to each turbine based on a turbine's capacity, vintage and location. The turbines were categorized into different groups based on various combinations of location as well as capacities and vintages. Operation and maintenance costs were then determined for each of the categories. In general, operation and maintenance costs (in kr/MWh) of older turbines are greater than the costs of newer turbines. Larger turbines, in terms of installed capacity, generally have smaller operation and maintenance costs than smaller turbines. There is an economies of scale effect for larger turbines. Finally, the operation and maintenance costs are larger for offshore turbines compared to onshore turbines given similar capacity and vintage.

Once again, the cost data are from the Balmorel model. Onshore turbines were split into six categories. The categories are combinations of three groups of vintages and two groups of capacities. For onshore generators

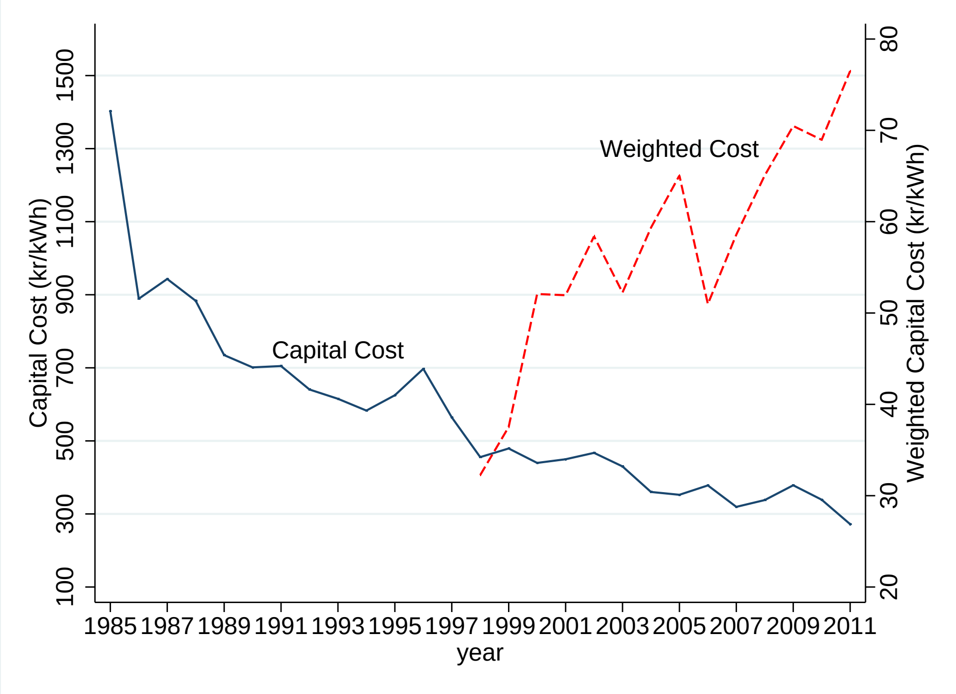

Figure 3.6: Aggregate Capital Costs, Wind Turbines, 1985-2011

constructed prior to 1996 with an installed capacity less than $500kW$, operation and maintenance costs were $kr115.61_{2011}/MWh$. For the same vintage of generators, but have a capacity greater than $500kW$, operation and maintenance costs were $kr104.05_{2011}/MWh$. For turbines with a capacity less than $500kW$ that were constructed between 1996 and 2006, operation and maintenance costs were $kr104.05_{2011}/MWh$. Turbines constructed between 1996 and 2006 with a capacity greater than $500kW$ had operation and maintenance cost of $kr93.65_{2011}/MWh$. For turbines constructed after 2006 with a capacity less than $500kW$ operation and maintenance costs were $kr98.23_{2011}/MWh$. Finally, turbines with a capacity greater than $500kW$ that were constructed after 2006 had operation and maintenance costs equal to $kr88.25_{2011}/MWh$.

Offshore turbines were split into three groups based on vintage and capacity. The operation and maintenance costs for an offshore turbine constructed prior to 1996 with an installed capacity less than $500kW$ were $kr153.77_{2011}/MWh$. For turbines constructed between 1996 and 2006 with an installed capacity greater than $500kW$ operation and maintenance costs were $kr124.56_{2011}/MWh$. Offshore turbines with a capacity less than $500kW$ constructed after 2006 have an operation and maintenance costs of $kr117.64_{2011}/MWh$. Onshore turbines were split into three groups because there were no turbines built after 1995 that had an installed capacity less than $500kW$. Moreover, offshore turbines constructed prior to 1995 had a capacity less than $500kW$.

The annual weighted average operation and maintenance costs are reported in column 3 of table 3.1. The costs do not vary too much from year-to-year. Any fluctuations in the annual average costs were due to changes in the mix of turbines through retirements and new installations. Second, the costs reported are weighted averages where the weights are each turbine's share of production. Therefore, changes in annual costs could also occur because of changes in the generation profiles of each turbine.

3.3.3 Aggregate Costs

The levelised generation costs are calculating by combining capital costs together with operation and maintenance costs. The costs are reported in table 3.1. In the second and third columns are reported the annual weighted average capital costs and operation and maintenance costs respectively. The weights were determined by each turbines production share of electricity generated by all wind turbines. In the last two columns of the table are reported two different cost calculations. Total costs are the annual weighted averages of the sum of capacity costs and operation and maintenance costs where the weights are each turbines production share of all electricity generated by wind turbines. Contribution to aggregate costs are the weighted average total costs where the weights are determined by each turbine's production share of aggregate electricity production including all thermal generation. The costs reported in the last column should be interpreted as the average contribution made wind turbines to aggregate generation costs.

The levelised costs of generating electricity from wind declined over time. The driving force behind the declining costs has been the reduction in capital costs. Recall from section that capital costs have been declining primarily for two reasons. First, the wind industry has continued to mature meaning improvement in construction practices and managements as well as improvement in technology. These improvements work to lower overnight construction costs. Second, capacities have gotten larger and capacity utilization rates have increased. Recent investments in offshore turbines have yielded larger capacity utilization rates, combined with larger capacities, resulting in lower per unit capital costs. Interestingly, wind turbines' average contribution to aggregate generation costs have been increasing over the same period. In fact, from 1998 to 2011, wind generation's contribution to overall generations costs more than doubled. This result is not surprising given that wind accounted for almost 28 percent of aggregate electricity generation in Denmark by 2011. In contrast, wind generation accounted for approximately five percent of aggregate Danish generation in 1998. How these changes in costs affected overall generation depends on the types of generation wind energy has replaced. If wind replaced high cost thermal generation then aggregate generation costs should decrease. Aggregate levelised costs is the subject of the next chapter. First, however, a brief overview of the state of solar and hydro energy is provided.

3.4 Hydro and Solar

The amount of electricity generated from solar and hydro sources is reported in figure 3.7. Solar and hydro does not contribute a significant amount of electricity to the Danish power system. Since 1998, the maximum contribution made by hydro to total electricity generation was less than 0.08 percent. Moreover, there is a clear long run declining trend in the amount of electricity generated from hydro. This trend is expected to continue in the foreseeable future as there is no discussion in the 2012 Energy Agreement concerning efforts to invest in hydro power.

In contrast, electricity generated from solar technologies has generally been increasing since 1999. Although, the amount generated from solar is still small relative to thermal and wind generation. In its peak year, 2011, Solar contributed less than 0.001 percent of aggregate electricity generated in Denmark. Current solar stations are small scale units with very small thermal capacities. The use of solar for generating electricity as well as for generating heat in district heating systems is expected to increase in the future.

Table 3.1: Aggregate Costs, Wind Turbines, 1998-2001 (kr/MWh)

	Land Turbines				Offshore Turbines			
Year	Capital Cost	Operation and Maintenance Cost[a]	Total Cost	Contribution to Agg. Cost	Capital Cost	Operation and Maintenance Cost	Total Cost	Contribution to Agg. Cost
1998	453.01	103.69	556.70	39.07	742.52	153.77	896.30	0.56
1999	476.59	101.56	578.16	44.95	849.98	153.77	1003.76	0.56
2000	428.06	99.82	527.88	62.11	2253.78	153.66	2407.44	1.83
2001	444.83	98.79	543.63	61.49	681.75	131.91	813.66	1.95
2002	444.77	98.32	543.09	65.51	1091.10	128.80	1219.90	5.31
2003	427.49	97.23	524.73	53.65	444.50	125.29	569.79	10.94
2004	370.29	97.09	467.38	62.56	316.68	125.16	441.85	13.65
2005	376.28	96.96	473.24	68.10	268.36	125.03	393.40	15.98
2006	404.76	96.84	501.60	52.48	285.71	124.98	410.69	12.40
2007	327.56	96.86	424.42	62.90	285.11	125.12	410.23	14.45
2008	360.96	96.56	457.52	68.81	256.38	125.03	381.40	16.04
2009	390.07	95.97	486.04	68.07	343.62	123.93	467.54	21.56
2010	383.70	95.33	479.03	63.88	254.04	121.40	375.44	26.31
2011	309.77	94.78	404.55	74.17	201.44	121.01	322.46	31.54

[a] Includes both fixed and variable costs.

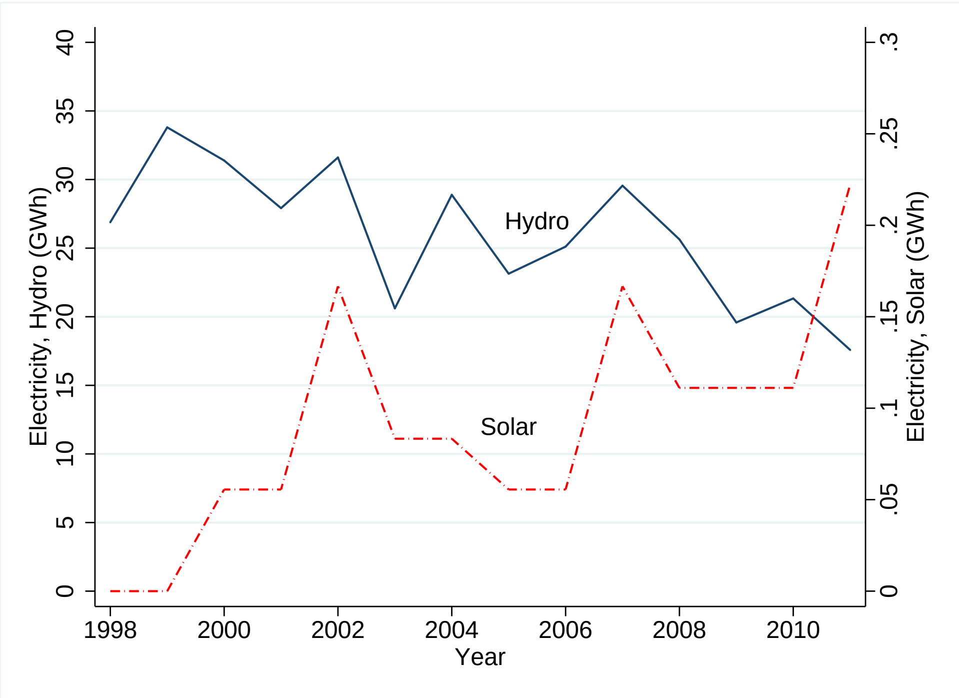

Figure 3.7: Electricity Delivered, Solar and Hydro, 1998-2011

Chapter 4

Conclusion

The main purpose of this paper was to compute the levelised costs of generating electricity for nine different generation technologies as well as provide an analysis of these costs. To this end, we applied the empirical methodology outlined in Chapter 3 of Levitt and Sørensen (2014).

The broad conclusions of this paper were:

- The average cost of generating electricity for most of the thermal generators increased over the 14 year period due to rising fuel prices.
- Capital costs did not increase over the 14 year period for those generating technologies that generated a large share of aggregate electricity.
- The share of aggregate electricity generated by wind turbines, both offshore and onshore, increased over the 14 year period: Shares increased from seven percent in 1998 to 28 percent in 2011. The share of costs, however, only increased from around eight percent to 18 percent during the same period, indicating that wind turbines were relatively inexpensive technologies.
- Unit capital costs had increased over the 14 year period for some thermal generators. This is the case for thermal generators with low and falling shares of deliveries. These technologies accounted for 9.4 percent of total deliveries in 2011; against 23.1 percent in 1998. Even though the share of deliveries dropped dramatically, the cost share of overall average production costs for these technologies only dropped from around one third in 1998 to 23 percent in 2011. This implies that electricity generation using these technologies is relatively expensive.

The levelised costs of electricity generation that were computed for the seven thermal technologies as well as for offshore and onshore wind turbines are used in the analysis of electricity generation in Denmark reported in Levitt and Sørensen (2014).

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Appendix A

Data

The sources of all the data were provided in the sections in the paper in which the data were used. However, it is convenient to have an overview of the data we used in the project in one place. To this end, we provide a summary of the data in this appendix.

A.1 Deflators

The deflator used to calculate real prices is a producer price index constructed by Statistics Denmark. In particular, we used the *Price Index for Domestic Supply by Commodity Group* (series PRIS10). We used the *raw materials for other industries commodity* group. The original index was reported using 2005 as the base year. The original index was adjusted to real 2011 prices.

A.2 Interest Rates

Interest rates were used to calculate the levelised investment costs for each generator. The main difficulty with obtaining informative interests was the need to obtain a consistent series dating back to the early 1950s. We used the effective bond interest rate (series *lwbz*) from ADAM. Rates date from 1948 providing a consistent set of interest rates. It is likely that these interest rates are a little lower than the financing rates actually offered to finance electricity generation projects.

A.3 Emissions Data

The prices for emission permits are the completed settlement prices as reported by the European Energy Exchange. The data was obtained via *Datastream* which is a database service provided by Thomson Reuters. The name of the series in the *Datastream* database is *EEX-EU CO2 Emission Settlement Prices*. The data was reported in Danish Kroner per metric tonne ($kr/MTonne$) at the monthly level. Annual prices were obtained by taking the mean of the monthly prices.

The emission factors used to calculate the quantity of carbon emitted by the generators are those used by the Danish Energy Agency to calculate the Danish Emission Inventories. The data is available from the Department of Environmental Science at Aarhus University: `http://envs.au.dk/en/knowledge/air/emissions/emission-factors/`. The factors were originally reported in kilograms per gigajoules (kg/Gj). The factors were converted to units $MTonne/MWh$ using the conversion $1kg/Gj = 0.0036MTonnes/MWh$.

A.4 Balmorel Data

The Balmorel model was the source for capital costs as well as for fixed and variable operation and maintenance costs. Two documents describing the model are Grohnheit and Larsen (2001) and Ravn (2012). In addition, the actual model together with documentation is freely available at `http://www.eabalmorel.dk/`.

A.5 Generators

Data on the production characteristics of all the generators in Denmark was provided by the Danish Energy Agency.

A.6 Fuel

Data on the amount and type of fuel used be each of the generators was included in the production data supplied by the Danish Energy Agency. Data on prices and expenditures were obtained from Statistics Denmark. In particular, we used the data reported in the table *ENE1HT: Energy Account in Specific Units by Supply and Type of Energy* as well as the data reported in the table *ENE4N: Energy Accounts in monetary values by industry, unit and type.*