Gone with the wind?

An empirical analysis of the renewable energy rent transfer

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Background

Who pays the cost of decarbonizating the economy?

Policy incidence

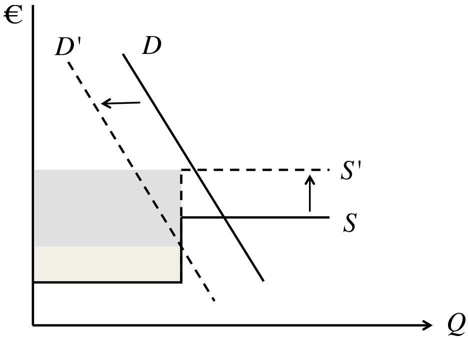

Figure 1: A schematic illustration of the policy cost incidence, with low and high cost of portions in supply. Carbon pricing increases the cost differentials in supply and the rent (in grey) to the existing low cost suppliers. In contrast, subsidies to new entrants shift the overall demand for the incumbent capacity to the left, and extract the rent.

This paper

The objective is to quantify the rent extraction

- The Nordic Market (Nord Pool)
- 50 % is hydro
- Hydro facilitates large scale entry of RE: intermittency
- Focus here: pressure on assets

Findings

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- WIND 2020: 10 % market share; additional 9-10 billion € annual transfer
  - HYDRO: 2/3 rents
  - NUCLEAR: 1/3 rents
  - THERMAL: fully stranded
- Each MWh WIND extracts 70-80 € of incumbent rent
- Subsidies cost neutral to consumers
  - 2/3 of consumer expenditures disappear
  - identifies the fraction of subsidies that can be recovered from the customers

The Market: Nord Pool

Figure: ca. 400TWh annual consumption. 200 TWh Hydro. The rest: Nuclear, CHP, Thermal, Wind. The NordPool: day-ahead spot market for wholesale electricity.

Empirical analysis

$$\underbrace{TOTAL.DEMAND}_{=D_t} = \underbrace{HYDRO + THERMAL}_{=d_t} + \underbrace{WIND + CHP + NUCLEAR}_{\text{price insensitive}}$$

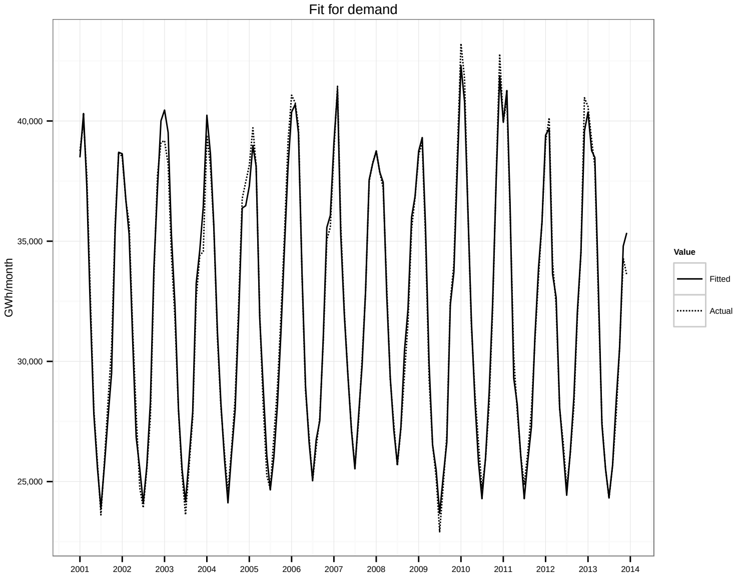
Illustration: TOTAL DEMAND

Table 10: TOTAL DEMAND FIT

	Dependent variable:
	demand
Jan	28.53^{***}
Feb	28.30^{***}
Mar	27.15^{***}
Apr	25.90^{***}
May	26.22^{***}
Jun	25.56^{***}
Jul	24.14^{***}
Aug	25.73^{***}
Sep	26.35^{***}
Oct	26.16^{***}
Nov	27.46^{***}
Dec	27.50^{***}
HDD	17.99^{***}
Observations	156
R^2	.97
Adjusted R^2	.98
Residual Std. Error	814.94 (df = 143)
F Statistic	$18{,}668.38^{***}$ (df = 13; 143)
Note:	*p<0.1; **p<0.05; ***p<0.01

Table 11: TOTAL DEMAND regressed on month dummies and heating degree days. HDD=heating degree days. Values measured in TWh.

Illustration: TOTAL DEMAND



Empirical analysis

Empirical strategy:

1. estimate HYDRO policies directly
2. use the policies to identify THERMAL supply and prices
3. counterfactual analysis: add more WIND to the market

Estimation: policies

- data period: 2001-2013
- all data at monthly level
- prices: the system price
- quantities: aggregated by technology
- trade: included in THERMAL
- CHP: prices sensitive part of CHP included in THERMAL

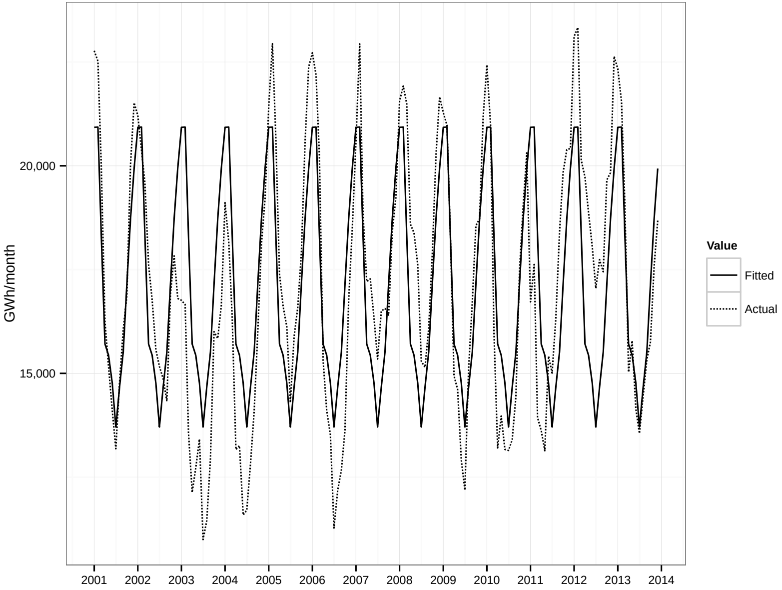
Estimation: policies

Table 2: Hydro fit with different model specifications

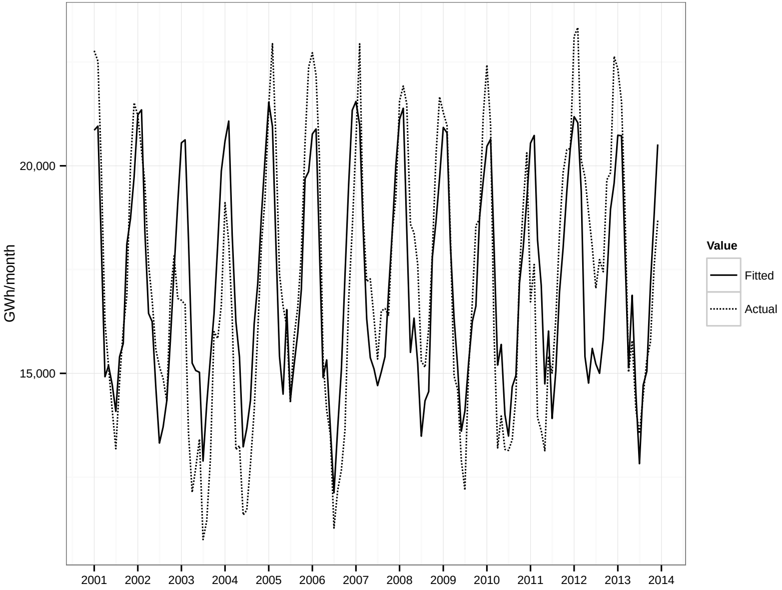
	Dependent variable:			
	hydro			
	(1)	(2)	(3)	(4)
inflow		0.14^{***}	-0.01	0.05^{**}
reservoir			0.15^{***}	0.13^{***}
res. demand				0.55^{***}
trend				7.90^{***}
Jan	20.93^{***}	20.93^{***}	20.87^{***}	20.30^{***}
Feb	20.93^{***}	20.94^{***}	20.98^{***}	20.40^{***}
Mar	18.33^{***}	18.33^{***}	18.45^{***}	17.84^{***}
Apr	15.71^{***}	15.71^{***}	15.73^{***}	15.12^{***}
May	15.44^{***}	15.44^{***}	15.19^{***}	14.61^{***}
Jun	14.77^{***}	14.77^{***}	14.77^{***}	14.15^{***}
Jul	13.71^{***}	13.71^{***}	13.93^{***}	13.28^{***}
Aug	14.67^{***}	14.67^{***}	14.89^{***}	14.23^{***}
Sep	15.51^{***}	15.51^{***}	15.64^{***}	14.98^{***}
Oct	17.14^{***}	17.14^{***}	17.29^{***}	16.63^{***}
Nov	18.72^{***}	18.72^{***}	18.90^{***}	18.23^{***}
Dec	19.93^{***}	19.93^{***}	20.04^{***}	19.37^{***}
Observations	156	156	156	156
R^2	0.62	0.66	0.86	0.93
Adjusted R^2	0.59	0.63	0.85	0.93
Residual Std. Error	1,991.46 (df = 144)	1,892.58 (df = 143)	1,211.49 (df = 142)	840.18 (df = 140)
F Statistic	983.64^{***} (df = 12; 144)	$1{,}006.59^{***}$ (df = 13; 143)	$2{,}295.85^{***}$ (df = 14; 142)	$4{,}186.51^{***}$ (df = 16; 140)

Note: *p<0.1; **p<0.05; ***p<0.01

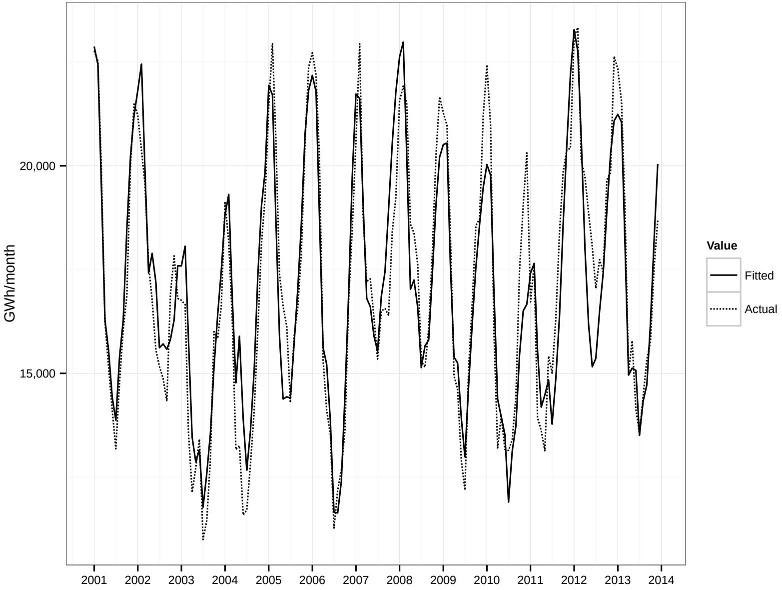
Estimation: seasons



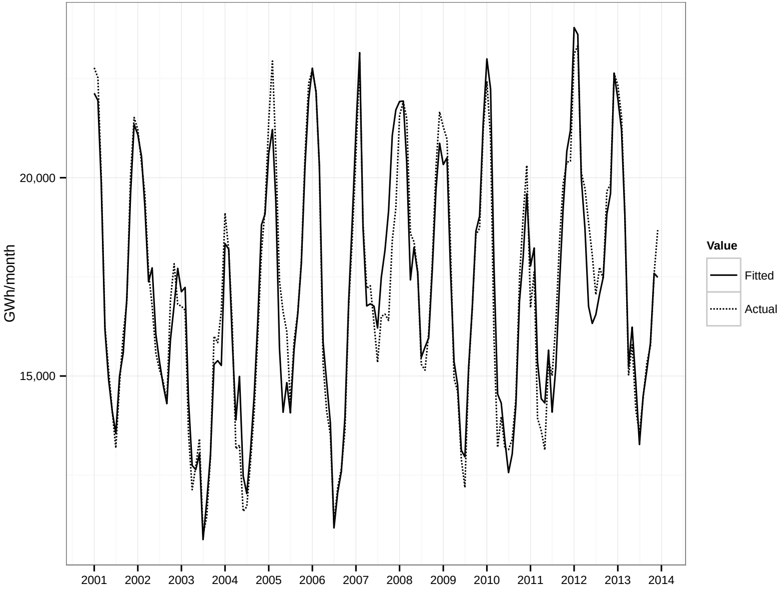
Estimation: seasons+inflows



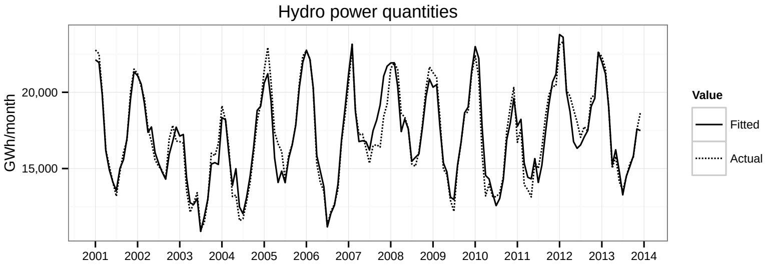
Estimation: seasons+inflows+reservoirs

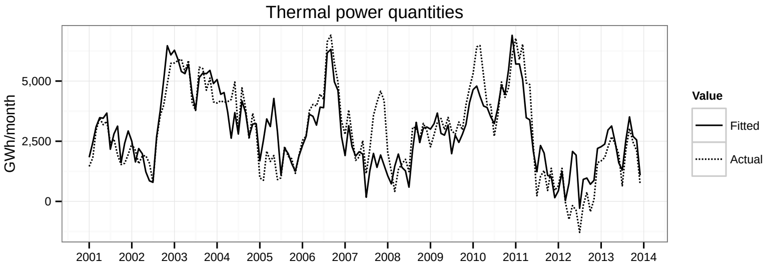


Est.: seasons+inflows+reservoirs+trend+res.demand



Estimation: looking at both HYDRO and THERMAL





Recovering prices: The price fit

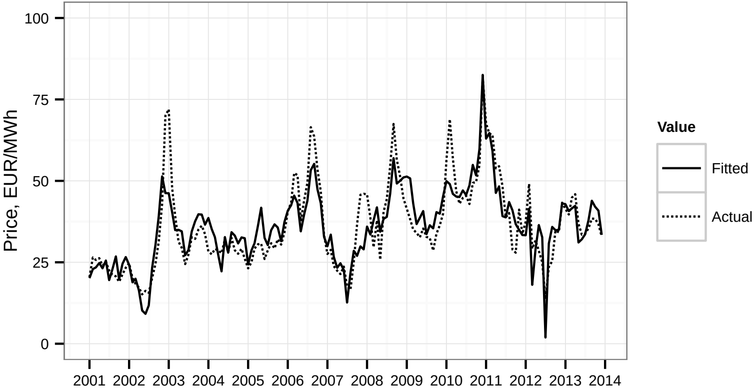


Figure: Monthly prices

Invariant Prices

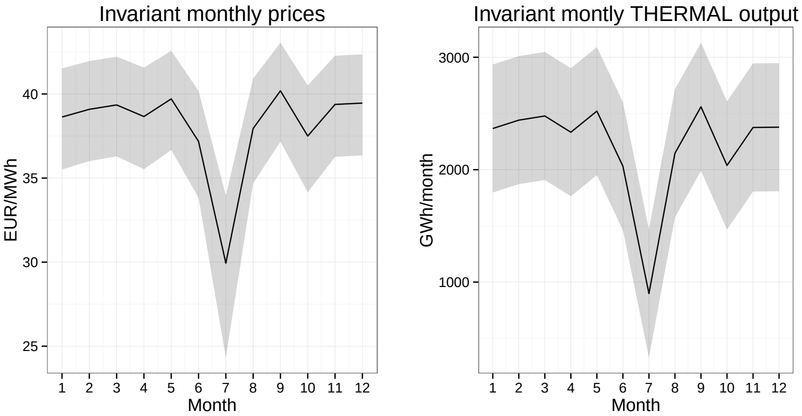


Figure: mean and the 95 % confidence intervals

The rent transfer

The analysis builds on:

1. the existing fleet of capacity units remains stable
   - we measure the pressure on the existing assets
2. thermal must response, on average, one to one to permanent increases in WIND
3. WIND is scaled up following the estimated pattern (which seems stable)

The WIND pattern

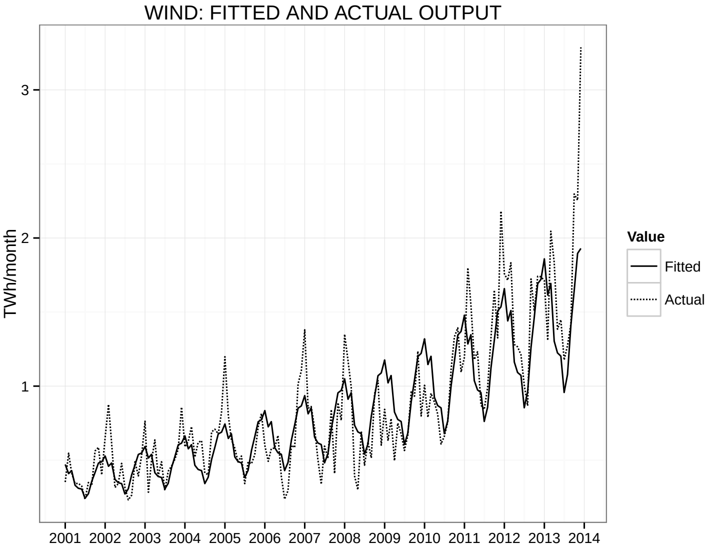


Figure: Monthly output

The consumer surplus

TWh WIND	low estimate	mean	high estimate
0	16,906	18,180	19,330
10	15,223	16,497	17,647
20	**13,517**	**14,791**	**15,941**
30	11,562	12,836	13,986
40	8,682	9,956	11,106
50	4,530	5,804	6,954

Table: Total annual invariant electricity market expenditures in the Nordic countries in millions of 2010 euros for Terawatt-hours WIND generated. Low and high estimates from the 95 per cent confidence interval (invariant distribution).

The surplus by region

TWh WIND	0	10	20	30	40	50
DEN	1,654	1,501	1,346	1,168	906	528
FIN	3,956	3,590	3,218	2,793	2,166	1,263
NOR	5,787	5,251	4,708	4,086	3,169	1,847
SWE	6,783	6,155	5,518	4,789	3,714	2,165
Total	18,180	16,497	14,790	12,836	9,955	5,803

Table: Annual invariant electricity market expenditures by country in millions of 2010 euros for Terawatt-hours WIND generated. Mean values reported.

The willingness to pay

TWh WIND	10	20	30	40	50
DEN	15	8	6	7	8
FIN	37	19	14	16	18
NOR	54	27	21	23	26
SWE	63	32	24	27	31
Total	**168**	**85**	**65**	**72**	**83**

Table: Consumer-side willingness to pay for MWh of wind generation: annual expenditure reduction (in 2010 euros) divided by the cumulative addition of wind generation (MWh), start from zero. Mean values reported.

The losses by technology

	0	10	20	30	40	50
HYDRO	10, 081	9, 151	8, 207	7, 125	5, 527	3, 246
NUCLEAR	4, 005	3, 637	3, 262	2, 833	2, 197	1, 299
CHP	2, 334	2, 110	1, 885	1, 628	1, 248	678
THERMAL	2, 200	1, 569	1, 025	561	191	0
WIND	0	429	768	999	1, 031	742
Total	18, 620	16, 896	15, 147	13, 146	10, 194	5, 944

Table: Annual invariant electricity market revenues losses by technology in millions of 2010 euros for Terawatt-hours WIND generated. Mean values reported.

Concluding remarks

•We know of no other empirical study looking at the longer-term surplus sharing from renewable energy entry

•Shortcomings:

- the estimated policies may not apply after large scale entry
- changes in the market environment not accounted for: interconnections, changes in capacity..
- may not apply other markets: assets become stranded

•The cost incidence matters for the overall climate policy architecture:

- The optimal policy should differentiate the tax across sectors that are differently exposed to competition (Hoel, 1996)
- The differentiation argument may justify subsidies.