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MARKET DRIVEN POWER PLANT INVESTMENT PERSPECTIVES IN EUROPE: CLIMATE POLICY AND TECHNOLOGY SCENARIOS UNTIL 2050 IN THE MODEL EMELIE-ESY

A. SCHRÖDER*, T. TRABER† and C. KEMFERT‡

DIW Berlin, Mohrenstr. 58
10117 Berlin, Germany
**AndySchroeder1@gmx.net*
†*ttraber@diw.de*
‡*ckemfert@diw.de*

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In the framework of the Energy Modeling Forum 28, we investigate how climate policy regimes affect market developments under different technology availabilities on the European power markets. We use the partial equilibrium model EMELIE-ESY with focus on electricity markets in order to determine how private investors optimize their generation capacity investment and operation over the horizon 2010 to 2050. For the year 2050, the model projects a minor increase of power consumption of 10% under current climate policy, and a balanced pathway for consumption under ambitious climate policy compared to 2010 levels. These results contrast with findings of POLES and PRIMES models that predict strong consumption increases of 44% to 48% by 2050 and claim competitiveness of nuclear power and CCS options. Under ambitious climate policy, our findings correspond with major increases of wholesale electricity market prices and comparatively less pronounced emission price increases, which trigger no investments into Carbon Capture and Storage (CCS) and a strongly diminishing share of nuclear energy.

Keywords: Electricity markets; investment; climate policy.

1. Introduction and Literature Review

Many existing studies analyze technology developments on the European power market. Results for electricity generation capacity of these studies vary greatly. For instance, the World Energy Outlook (IEA, 2011) expects capacity expansion of gas-fired plants, coal-fired plants, and nuclear power in Europe. A study of EWI (2012) projects gas-fueled generation capacity investment to almost double by 2030 while investment in other conventional resources ought to decline. The Energy Roadmap of the European Commission (EC, 2011) outlines several scenarios of power capacity

†Corresponding author.
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developments by 2050. In most Roadmap scenarios, fossil-fuel based power capacity remains roughly constant until 2050. CCS capacity is projected to be deployed and nuclear power capacity is expected to increase slightly in the reference scenario. As drivers of the differences in capacity developments, we can distinguish between modeling approaches, the consideration of back-up capacity requirements, and the development of Renewable Energy Sources (RES) as source of electricity.

First, the choice of the applied modeling approach and input data generally affects the model output and has to be considered in the comparison of results regarding the electricity system developments. Some projections are based on simple estimations without model underpinning (BDEW, 2011). Models such as those of Haller (2012), dena (2008), Maurer *et al.* (2012), and EWI (2012) use linear or nonlinear optimization for determining system capacities required to cover peak demand, while total demand evolves exogenously. By contrast, equilibrium modeling approaches of the World Energy Outlook (IEA, 2011) and the roadmap of the European Commission (EC, 2011) add sophistication by capturing market effects such as price elastic demand and investment as well as interactions between national market areas and various parts of the broader energy sector including heat and transportation. The results outlined in the two latter publications are challenged in Schroeder *et al.* (2013) on the grounds of relatively optimistic assumptions on cost for investments in nuclear power plants and power plants with carbon capture and storage (CCS) facilities.

A second difference in modeled capacity developments is driven by assumptions in regard to requirements for back-up capacities. The need for reliable back-up power production capacities in response to rising renewable energy production levels has in recent years prompted a vivid discussion among academics and practitioners about the feasibility of energy systems that are based on a large share of renewable energy. Several studies have specifically reviewed the need for investment into new back-up facilities. Some of the studies looked at the national level (BDEW, 2011; dena, 2008; Knopf *et al.*, 2011; Maurer *et al.*, 2012), but there are also studies that consider an integrated European market (EC, 2011; EWI, 2012; IEA, 2011). For example EWI (2012) derives a demand for back-up capacity of about 39 GW single cycle gas turbines by 2030 in Germany alone (more than 20% of 2030 system capacity), while Maurer *et al.* (2012) calculate total necessary additional investments in fossil fuel power plants of between of 19 GW and 32 GW (up to 20% of current system capacity) as necessary by the same time horizon. Clearly, given almost constant fossil-fuel based power capacity as in EC (2011), the need for additional back-up capacities is minor compared to scenarios which project a significant decline of reliable thermal capacity. However, the explicit inclusion of back-up capacities does neither change the power production projection nor the total electricity system costs significantly since these plants have limited utilization and comparatively low capital cost (EWI, 2012). Furthermore, increased demand-side flexibility and higher price volatility may increase the elasticity of demand and therefore reduce the need for back-up units in case of a success of the politically envisaged roll-out of smart meters and smart grids (Faruqui *et al.*, 2010; Stromback *et al.*, 2011).

Thirdly, a difference in model results may also be induced by the assumed costs and potentials of bioenergy and further RES. Renewable electricity supply by bioenergy power plants plays an important role in some assessments that reach ambitious climate scenarios, particularly in combination with CCS (Edenhofer *et al.*, 2010; van Vuuren *et al.*, 2011). Nonetheless, the studies cited above project the bulk of electricity supply to come from RES based on photovoltaic and wind power plants, which experienced pronounced cost decreases in the last decade. These technologies have very low marginal generation costs such that prices tend to be determined by the higher marginal costs of fossil fuelled generation. Under these conditions it is plausible to model the supply of renewable electricity exogenously, not the least since exogeneity has the advantage of allowing comparability of results across models and scenarios.

Our study distinguishes itself by taking an energy-only market viewpoint with elastic demand and a given supply of electricity from renewable energies. Market investments are financed purely by energy sales and have to recover a comparatively high private discount rate of 8% in real terms on top of the comparatively high investment cost estimates for large scale power plants found in latest studies. These assumptions allow for answering the research question of how a pure energy-only market solution is likely to evolve under increasing fuel and emission prices when the costs of low carbon technologies like nuclear power and CCS are less favorable.

The applied model "EMELIE-ESY" computes a partial equilibrium of the electricity markets in Europe. In this framework, private investors optimize the fossil fuelled generation capacity investment and the hourly operation of these power plants ("dispatch") over a long-term horizon up to 2050 on the basis of electricity and emission prices. Furthermore, the model includes the effect of power plant ramp-up restrictions on the hourly supply profile of an exemplary day and the consequent impact on price profiles in each country. Accordingly, EMELIE stands for Electricity Market Liberalization in Europe — and ESY refers to energy symmetry in regard to supply and demand. With its strictly market-based approach, EMELIE-ESY adds a distinctive feature in comparison to the analysis provided by other state-of-the-art models such as the PRIMES and POLES.

In the model application presented here fundamental determinants of investment and dispatch decisions are investigated. The EMF28 scenario set-up is used in assessing the implications of climate policy targets and technology availability on technology choices for conventional power plants. We study the impact of climate policies and technology availability on market outcomes with regard to investment choices and the power mix. We find that the European electricity sector will be able to meet stringent climate policy targets without relying on contentious technologies such as nuclear power and CCS if an accelerated role out of RES is realized. EMELIE-ESY demonstrates how the conventional power sector develops under these targets relying on forces induced by power and emissions markets. EMELIE-ESY connects to IEA (2011) and EC (2011) in the coverage of whole Europe and the use of an equilibrium format in determining results. A difference of our approach is the focus on market-based behavior reflecting a private-investor perspective but omitting any system-determined minimum requirements for generation capacity. It thus adds to the field of literature by giving an insight on how likely power capacity investments are under current market design as opposed to an optimization that includes system capacity requirements.

The contribution forms part of the Energy Modeling Forum 28 (EMF28) study which is based on a comparison of results from a variety of well documented energy models. The EMF28 study focuses on the impact of energy technology availability on the costs of achieving European climate policy targets with different stringencies of the emission trading system. As such, the EMF28 context provides a unique opportunity to directly relate the results of the EMELIE-ESY model to other models in the EMF28 model comparison.

The paper is structured as follows. In the methods section, key model features and the model formulation as well as the different scenarios are outlined. Results are presented in Sec. 3, followed by a conclusion.

2. Method

2.1. *Model application*

The EMELIE-ESY model is a partial equilibrium model of the power sector. Aiming for profit maximization, agents make investment decisions for conventional technologies and dispatch decisions. It constitutes an integrated multi-period investment-dispatch model. The model's main outputs are electricity wholesale market prices, carbon prices, production and demand volumes as well as investments into conventional generation capacity. Critical exogenous input components are — amongst others — reference demand levels, the evolution and production profile of renewable energies, price-elasticity of demand, and full production costs as indicated in Table 1. In the EMF28 model comparison study, we apply EMELIE-ESY to determine generation capacity investment and operation over the horizon 2010 to 2050 for whole Europe EU27+2. In order to make EMELIE-ESY results comparable to those in the models PRIMES and POLES, some critical input assumptions such as the evolution of reference demand and renewable energy production as well as production costs are discussed and — if possible — aligned with PRIMES and POLES. The added value of comparing EMELIE-ESY results with PRIMES and POLES contributions to EMF28 lies in the detailed representation of the power sector in EMELIE-ESY, notably in terms of wholesale market price profiles and demand reaction to market prices.

2.2. *Model description*

EMELIE-ESY is a Mixed Complementarity Problem (MCP). The algebra of the model formulation is presented below and corresponds to the model used in Traber and Kemfert (2012). Equations (1)–(13) (Table 2) show the original problem formulation before conversion into complementarity format. Parameters, sets and variables are outlined in Table 1. The problem covers long-term periods (a), short-term time steps

Table 1. Model sets, parameters, and variables.

Indices		
a	Year	
t	Hour	
s, ss	Region	
n	Generation technology	
i	Player	
ar	Arbitrageur	
Decision variables of private investor (endogenous)		
$\mathrm{EX}^{(i,t,a,s)}$	Export	MWh
$\mathrm{IM}^{(i,t,a,s)}$	Import	MWh
$L^{(i,t,n,a)}$	Load gradient	MW
$P^{(t,a,s)}$	Price	EUR
$Q^{(i,t,n,a)}$	Production	MWh
$\mathrm{TQ}^{(n,t,a)}$	Total production of all firms	MWh
$X^{(i,n,a)}$	Investment	MW
Shadow prices (endogenous)		
$\gamma^{(t,a)}$	Shadow price of reserve capacity requirement	EUR/MW
$\delta^{(i,t,n,a)}$	Shadow price of load gradient definition	EUR/MW
$\kappa^{(i,t,n,a)}$	Shadow price of capacity constraint	EUR/MW
$\lambda^{(i,t,n,a)}$	Shadow price of ramp-up constraint	EUR/MW
$\rho^{(i,n,a)}$	Shadow price of capacity expansion limit	EUR/MW
$\tau^{(t,a,s)}$	Shadow price of Net Transfer Capacity	EUR/MW
$\Phi^{(a)}$	Shadow price of carbon emissions cap	EUR/t
Parameters (exogenous)		
$\mathrm{av}^{(n)}$	Availability	%
$c_d^{(n)}$	Marginal depreciation while ramping	EUR/MW
$c_e^{(n,a)}$	Marginal emission cost	t/MWh
$c_f^{(n,a)}$	Fuel cost	EUR/MWh
$c_L^{(n,a)}$	Marginal ramping cost	EUR/MW
$c_o^{(n)}$	Operating cost	EUR/MWh
$c_Q^{(n,a)}$	Marginal cost of generation	EUR/MWh
$c_{\mathrm{re}}^{(n,a)}$	Marginal ramping emission cost	t/MW
$c_X^{(n)}$	Investment cost	EUR/MW
$d^{(a)}$	Discount rate	%
$d_0^{(t,s)}$	Reference demand	EUR
$\mathrm{emf}^{(n)}$	Emission factor	t/MWh
$\mathrm{cap}^{(a)}$	Emission cap	t/year
$\mathrm{int}^{(t,a,s)}$	Intercept of demand curve	
$\bar{l}^{(i,n,a)}$	Maximum load gradient	%/hour
$\mathrm{local}^{(i,s)}$	Mapping of firm to region	Binary
$\eta^{(n)}$	Efficiency	%
$\mathrm{ntc}^{(t,a,s,ss)}$	Net Transfer Capacities	MW
$p_0^{(t,s)}$	Reference price	EUR
$\bar{q}^{(i,n,a)}$	Installed capacity	MW

Table 1. (*Continued*)

$\text{res}^{(t,a,s)}$	RES and CHP feed-in	MW
$s^{(n)}$	Ramp-up fuel requirement	MWh/MW
$\text{slp}^{(t,a,s)}$	Slope of demand curve	
σ	Price elasticity of demand	
$w^{(a)}$	Number of representative days per model period	
$\bar{x}^{(i,n,a)}$	Maximum capacity expansion	MW

for dispatch (t), generation technologies (n), firms (i), and regions (s, ss). Firms maximize their individual expected and discounted profits π over the modeling period, i.e., revenues net of production costs and fixed investment cost (Eq. (1)). The set of variables comprises investment ($X^{i,n,a}$) as well as ramping ($L^{i,t,n,a}$) and generation decisions ($Q^{i,t,n,a}$). Firms are constrained by a market balance and capacity restrictions for generation as well as ramping limits up to a specific maximum load gradient (Eqs. (3) to (6)). The market balance ensures that demand net of RES feed-in equals power supply at each point in time. Generation (Eq. (4)) and ramping capacity limits (Eqs. 5 and 6) make sure that generation dispatch follows rules imposed by technical constraints. Equation (7) puts an upper limit to investment into specific technologies. Equation (8) defines the yearly emission cap for the whole power sector. Dual variables

Table 2. Model equations.

Profit of firm

$$\max_{Q,X,L} \pi_i = \sum_{\{a\}}^{A} \left[\left[\sum_{\epsilon\,\text{local}}^{S} \sum_{\{t=1\}}^{T} \sum_{\{n=1\}}^{N} (P^{\{t,a,s\}} \times (\text{TQ}^{\{t,n,a\}}) Q^{\{i,t,n,a\}} - c_{\{Q\}}^{\{n,a\}} Q^{\{i,t,n,a\}} - c_{\{L\}}^{\{n,a\}} L^{\{i,t,n,a\}}) w^a - c_{\{X\}}^{\{n\}} X^{\{i,n,a\}} \right] \frac{1}{1+d^{\{a\}}} \right]. \tag{1}$$

Profit of arbitrageur

$$\max_{\text{EX}} \pi_{\text{ar}} = \sum_{\{a\}}^{A} \left[\left[\sum_{\epsilon\,\text{local}}^{S} \sum_{\{t=1\}}^{T} \sum_{\{n=1\}}^{N} (P^{\{t,a,ss\}}(\text{TQ}^{\{t,n,a,ss\}}) - P^{\{t,a,s\}}(\text{TQ}^{\{t,n,a,s\}})) \times \text{EX}^{\{i,t,n,a,s,ss\}} w^a \right] \frac{1}{1+d^{\{a\}}} \right]. \tag{2}$$

Table 2. (*Continued*)

Market balance $P^{\{t,a,s\}} \perp$	$P^{\{t,a,s\}} - \sum_{i=1}^{I} \sum_{n=1}^{N} (p_0^{\{t,s\}} - \mathrm{slp}^{\{t,a,s\}}(Q^{\{i,t,n,a\}} + \mathrm{res}^{\{t,a,s\}} - d_0^{\{t,s\}})) \geq 0.$ (3)
Generation capacity limit $\kappa^{\{i,t,n,a\}} \perp$	$\left(\bar{q}^{\{i,n,a\}} + \sum_{\{a \in \mathrm{pred}(a)\}}^{A} X^{\{i,n,a\}}\right) \mathrm{av}^{\{n\}} - Q^{\{i,t,n,a\}} \geq 0.$ (4)
Load gradient upper limit $\delta^{\{i,t,n,a\}} \perp$	$\bar{l}^{\{i,t,n,a\}} \left(\bar{q}^{\{i,n,a\}} + \sum_{a=1}^{A} X^{\{i,n,a\}}\right) \mathrm{av}^{\{n\}} - L^{\{i,t,n,a\}} \geq 0.$ (5)
Load gradient lower limit $\lambda^{\{i,t,n,a\}} \perp$	$L^{\{i,t,n,a\}} - Q^{\{i,t,n,a\}} + Q^{\{i,t-1,n,a\}} \geq 0.$ (6)
Capacity expansion limit $\rho^{\{i,n,a\}} \perp$	$\bar{x}^{\{i,n\}} - X^{\{i,n,a\}} \geq 0.$ (7)
Emissions cap $\phi^{\{a\}} \perp$	$\sum_{t=1}^{T} \sum_{i=1}^{I} \sum_{n=1}^{N} \mathrm{emf}^{\{n\}}(Q^{\{i,t,n,a\}}) - \mathrm{cap}^{\{a\}} \geq 0.$ (8)
Net Transfer Capacities $\tau^{\{t,a,s,ss\}} \perp$	$\mathrm{ntc}^{\{s,ss\}} \sum_{i=1}^{I} \mathrm{EX}^{\{i,t,a,s,ss\}} \geq 0.$ (9)
Intercept	$\mathrm{int}^{\{t,a,s\}} = p_0^{\{t,a,s\}} - \mathrm{slp}^{\{t,a,s\}} \cdot d_0^{\{t,a,s\}}.$ (10)
Slope	$\mathrm{slp}^{\{t,a,s\}} = \frac{p_0^{\{t,a,s\}}}{d_0^{\{t,a,s\}} \sigma}.$ (11)
Generation cost	$c_Q^{\{n,a\}} = \frac{c_f^{\{n,a\}}}{\eta^{\{n\}}} + c_o^{\{n\}} + \frac{\mathrm{emf}^{\{n\}}}{\eta^{\{n\}}} \phi^{\{a\}}.$ (12)
Ramping cost	$c_L^{\{n,a\}} = s^{\{n\} c_f^{\{n,a\}}} + c_{\{d\}}^{n} + \mathrm{emf}^{\{n\} s^{\{n\}}} \phi^{\{a\}}.$ (13)

are listed under the naming of each constraint. Equations (10) to (13) specify the linear demand function, generation cost, and the cost of ramping up power generation between two steps in time.

An arbitrageur makes sure that price differences between regions are used for import and export (Eq. (2)). Trade between regions is constrained by physical transmission limits, called Net Transfer Capacities (NTC), as detailed in Eq. (9). We solve the problem as MCP with Karush–Kuhn–Tucker conditions (KKT). It is coded in the General Algebraic Modeling System (GAMS) software.

2.2.1. *Regional resolution*

In terms of regional resolution, the model application includes all countries of the EU-27 plus Norway and Switzerland. Some countries are merged into groups. Spain and Portugal are grouped into IBERIA; Great Britain and Ireland are included as British Isles; Denmark, Sweden, and Finland constitute the regional aggregate NORDIC; Lithuania, Latvia, and Estonia are represented as BALTIC, while the group SOUTHEAST comprises Slovakia, Slovenia, Hungary, Romania, Bulgaria, and Greece. Finally, Belgium and Luxemburg are merged into one group.

2.2.2. *Temporal resolution*

The temporal coverage is five 10-year periods representing the range from 2010 to 2050. Each 10-year period encompasses a dispatch stage represented by 24 consecutive hours. Hence, each 10-year period is represented by one representative day in hourly resolution. The set-up of 10-year periods and hourly dispatch is chosen to combine long-term and short-term elements of investment planning. We should note that a representative day at the dispatch stage does not take into account less probable extreme events such as extremely low production of wind power.

2.2.3. *Transmission*

The projections of the grid structure and corresponding NTC between countries are taken from ENTSO-E (2012). Winter and Summer NTCs are taken to build averages. The expansion of the grid is line with indications in the EC Roadmap (EC, 2011). The EMELIE-ESY model represents import–export-transfers between countries with a simplified grid representation under scarcity pricing regime as outlined in Traber and Kemfert (2012). Scarcity pricing refers to the fact that transmission line congestion effects are priced into market prices. The simplified grid model considers electricity trade patterns disregarding physical flow characteristics such as loop flows.

2.2.4. *Demand and energy efficiency scenarios*

Electricity consumption is endogenous to the model and represented with linear, country-specific demand functions which are constructed around a reference point representing historic realizations of consumption and prices. Price-elasticity of demand at the reference point is set to −0.3 throughout all time periods and regions. The true elasticity is a huge unknown and there is no conclusive outcome in relevant literature about what figure to use (Bernstein and Griffin, 2006). Maddala *et al.* (1997) estimates short-term elasticities in the range of −0.16 to −0.28 and long-term elasticities in the range of −0.87 to +0.24 in the long-run. In this line, Garcia-Cerutti (2000) estimates a mean of −0.17 for residential consumers but with high deviations in the data. Our assumption of −0.3 lies in the range of estimates and was chosen as it best reflects results in the calibration year 2010.

Regarding reference demand, we use average hourly demand values of the year 2010 published by ENTSO-E for each country. The evolution of demand is varied by scenario.

Reference spot market (day ahead) prices are taken from several European energy exchanges. We use Nordpool prices for the specification of the Norwegian, Nordic, and Baltic markets. Poland and the Czech Republic are assigned Polish Power Exchange prices (exchange rate 4.2 PLN/EUR). SWISSIX prices are used for Switzerland. The remaining regions are assigned Phelix EEX power prices. Reference consumption is based on values published by ENTSO-E. The values for the German market are adjusted for the consumption of railroads and industries not connected to the public grid and therefore not accounted for by ENTSO-E.

2.2.5. *Renewable energy*

RES capacities, i.e., wind, solar, biomass, and hydro are treated as exogenous feed-in based on the National Renewable Energy Action Plans (NREAPs) up to 2020, and a trend projection until 2050 (EEA, 2012). Their hourly supply profile is fixed in each scenario and based on the average German profiles, scaled to the generation values of the NREAPs to represent different regions and periods. Scaling up average German RES profiles has some disadvantages as it neglects balancing effects of intermittent RES generation across EU countries. Hence, overall European RES feed-in is smoother than our profiles suggests. The assumption implies that investments into conventional generation as back-up to RES may tend to be over-estimated.

RES feed into the market at zero marginal costs. Their domination in the future power system puts downward pressure on wholesale market prices. In EMELIE-ESY, it is assumed that intermittend RES, namely solar and wind power, cannot be curtailed or stored. This implies that conventional generation can function as back-up system in case RES do not cover demand. In the EMELIE-ESY model set-up, the availability and use of back-up conventional generation is one of the key price-setting drivers in wholesale markets dominated by RES.

2.2.6. *Conventional generation*

On the supply side, the dispatch of conventional generation — including hydro power — is modeled endogenously. Up to 14 "dispatchable" generation technologies are reflected in the model as indicated in Table 3. Coal-fired plants are sub-divided by age of first commercial operation (boiler-criticality used as criterion for differentiation), fuel type, and CCS availability. Gas- and oil-fired plants are divided by turbine type. Nuclear power plants are distinguished by vintage, in order to reflect evolutions from ordinary generation III reactors towards new-type reactors such as EPR and AP-1000.

Overnight capital cost ranges between 6000 EUR/kW for new EPR nuclear reactors to 400 EUR/kW open cycle gas turbines (Gas GT) (Schroeder *et al.*, 2013). Following the assumed potential for technological development, investment costs of CCS-Technologies, nuclear reactors, and combined cycle gas turbines show a decreasing cost trend, whereas investment costs expressed in current monetary value for mature technologies are constant.

We further distinguish generation technologies by technological characteristics such as efficiency, (variable) operation and maintenance costs, start-up fuel requirements, ramping limits, fuel emissions, start-up depreciation, and availability. Values are fixed over the model time horizon as laid out in Table 4. Note that O&M costs for nuclear power include a surcharge for nuclear waste disposal but omit insurance cost, as detailed in Schroeder *et al.* (2013). Variable generation cost of nuclear power therefore lies at 25 EUR/MWh. Ramping restrictions are reflected at the dispatch stage in order to represent inflexibilities in the scheduling of power plant commitment.

Major drivers of the full costs of generation are fuel prices. As fuel prices are determined exogenously in EMELIE-ESY, we follow fuel price assumptions of IEA projections (IEA, 2011), as outlined in Table 5. Note that fuel prices differ across scenarios in our comparison models POLES and PRIMES, whereas they are constant

Table 3. Investment costs of generation capacity.

			Investment cost in EUR_{2010}/kW				
Group	Description	EMF28 denomination	2010	2020	2030	2040	2050
Nuclear	Generation 3 Old Nuclear	Nuclear	6000	5833	5671	5513	5360
	Generation 3 EPR Nuclear	Nuclear	—	—	—	—	—
Coal	Lignite Subcritical	Coal|PC|w/o CCS	—	—	—	—	—
	Lignite Supercritical	Coal|PC|w/o CCS	1700	1700	1700	1700	1700
	Old Subcritical	Coal|PC|w/o CCS	—	—	—	—	—
	Coal Supercritical	Coal|PC|w/o CCS	1300	1300	1300	1300	1300
	Lignite Oxyfuel CCS	Coal|PC|w CCS	3881	3577	3296	3038	2800
	Coal IGCC CCS	Coal|IGCC|w CCS	2988	2794	2613	2443	2285
Gas	Gas Precombustion CCS	Gas|CC|w CCS	1637	1528	1425	1330	1241
	Gas Combined Cycle	Gas|CC|w/o CCS	800	764	729	696	664
	Gas Combustion Turbine	Gas|CT	400	400	400	400	400
	Gas Steam Turbine	Gas|CT	—	—	—	—	—
Oil	Oil Steam Turbine	Oil|w/o CCS	—	—	—	—	—
	Oil Combustion Turbine	Oil|w/o CCS	—	—	—	—	—
Hydro	Hydroelectric	—	—	—	—	—	—

Table 4. Technological characteristics of generation technologies.

	Efficiency [%]	O&M costs [cent/kWh]	Start-up fuel [kWh/kW]	Maximum load gradient [%/hour]	Fuel emission [kg/kWh]	Start-up depreciation [cent/kW]	Availability [%]
Nuclear	0.34	1.8	16.7	0.04	0.00	0.5	0.81
Coal CCS	0.40	3.6	8.0	0.30	0.04	0.5	0.84
Coal	0.46	0.6	6.2	0.30	0.35	0.5	0.82
Lignite	0.43	0.6	6.2	0.08	0.40	0.3	0.85
Lignite CCS	0.31	4.1	8.0	0.08	0.05	0.3	0.87
Gas CCS	0.48	1.9	2.0	0.30	0.02	1.0	0.92
Gas CC	0.60	0.2	2.0	0.50	0.20	1.0	0.92
Gas GT	0.45	0.2	1.1	1.00	0.20	0.5	0.92

Table 5. Fuel price assumptions.

EUR_{2010}/MWh_{fuel}	2010	2020	2030	2040	2050
Lignite	0.3	0.4	0.4	0.5	0.5
Hard Coal	1.3	1.3	1.4	1.6	1.7
Natural Gas	2.3	3.0	3.4	3.7	4.1
Uranium	0.2	0.2	0.2	0.2	0.2

across scenarios in EMELIE-ESY. The assumed growth rates of oil prices are closely in line with PRIMES in the reference scenario. Gas prices are roughly doubled between 2010 and 2050 in EMELIE-ESY but more than tripled in PRIMES' reference scenario.

The decommissioning of existing generation capacity is set exogenously in line with existing and near-term planning up to 2020 as indicated in the Platts database (Platts, 2011). For the period from 2030 onwards, we use a heuristic to approximate limits for new investments based on the replacement of retiring capacities. More precisely, natural gas and hard coal investments are allowed to overcompensate the decommissioning according to lifetime expectancy by 100%, while investments in lignite capacities may at most replace decommissioning.

2.3. *Scenarios*

The 10 scenarios that we analyzed were defined within the EMF28 model comparison study. They are summarized in Table 6 together with the abbreviations that we use in the following and they are grouped along a technology availability dimension (horizontal) and a policy dimension (vertical).

The policy dimension prescribes a reduction of greenhouse gas emissions until 2050 by 40% in the reference case and by 80% in the mitigation scenario, both

Table 6. Scenario overview.

	Default w CCS	Default w/o CCS	Pessimistic	Optimistic	Green
CCS	on	off	off	on	off
Nuclear energy	reference	reference	low	reference	low
Energy efficiency	reference	reference	reference	high	high
Renewable energies	reference	reference	reference	reference	optimistic
Reference: including the 2020 targets and 40% CO_2 reduction by 2050	40%DEF	40%noCCS	40%PESS	40%EFF	40%GREEN
Mitigation: 80% CO_2 reduction by 2050 (with Cap&Trade within the EU)	80%DEF	80%noCCS	80%PESS	80%EFF	80%GREEN

Source: EMF28 Model Comparison.

compared to values of 1990. These policies are implemented in EMELIE-ESY by emission caps for the electricity sector. The reduction path for the power sector is actually tighter than the economy-wide path with targets of 40% or 80% by 2050. In line with the Energy Roadmap of the European Commission (EC, 2011), we use targets which gradually reduce the carbon emissions of the electricity sector compared to sectoral carbon emissions in 2010 (1.265 GT CO_2) by two thirds in the reference case and by 97.2% in the mitigation scenario.

The specifications of technology scenarios are further detailed in the subsections hereafter.

2.3.1. *Demand and energy efficiency scenarios*

Starting from reference prices and consumption of the year 2010, reference consumption is set to increase by 10% per decade for OECD countries and 20% per decade for non-OECD countries in all scenarios where energy efficiency is set to "reference". In the energy efficiency "high" scenario, reference demand only grows by 5% and 10% per decade respectively.

2.3.2. *Renewable energy scenarios*

RES capacity evolution and production profiles are treated as exogenous in all scenarios. Beyond the NREAPs projections of 2020, we assume a linear trend expansion of the RES capacities up to 2050 in the renewable energy reference ("reference") case. In the scenarios with "optimistic" RES development, the growth of production is double the growth of reference scenarios in absolute terms.

2.3.3. *Conventional generation scenarios*

The availability of generation technologies differs across the scenarios outlined in Table 6. "Off" denotes the non-possibility of investment into CCS technology. "On" refers to the availability of CCS in certain countries. For nuclear power, "low" means there is no possibility of new-built nuclear power plants in any country. In the "reference" case, upper limits for investment into nuclear power are set at either the level of currently planned projects or the amount of power plants decommissioned after 50 years of operation — depending on which number is greater. These limits are constructed so as to allow countries for at least keeping their current nuclear capacity levels and possibly expand their capacity, if current plans of new built exist.

In the scenarios denoted "reference" nuclear technology construction is confined to currently planned projects until 2020 or to the amount of decommissioned capacity in the corresponding decade if the latter number is greater. For the decades following 2020, current plans until 2020 are used as a proxy for planning. Only in Germany, decommissioning of old capacities does not imply the option of new investments. The scenarios denoted "reference" disregard policy decisions taken in countries like Belgium and Sweden and, thus, indicate an optimistic potential for nuclear investments. In contrast, the scenario "nuclear low" nuclear production relies on existing capacities or plants currently under construction which are decommissioned after 50 years of lifetime or according to the German nuclear phase-out policy. Finally, in scenarios denoted "reference" CCS capacity limits follow the expansion limits of ordinary gas and coal plants as indicated above, whereas the scenario CCS "off" does not allow for construction of CCS power plants.

3. Results

Results are compared explicitly to the models PRIMES and POLES. PRIMES is a reference model since it is frequently used by the European Commission, for instance for the EU Energy Roadmap (EC, 2011). POLES is used as reference because of its similar format as partial equilibrium model with detailed treatment of power markets.

3.1. *Wholesale spot price projections*

EMELIE-ESY is designed to calculate plausible electricity wholesale prices in the long run. The model relies on long-run marginal cost pricing plus an additional price component which reflects ramping costs of power plants. Therefore, modeled electricity prices cover all costs for the operators and investors of the marginal power plant, i.e., the investment which breaks even with a return of 8% per year.

The comparison of the average volume weighted wholesale electricity price projections in Fig. 1 essentially reveals three distinct pathways. The change rate from 2010 to 2050 ranges from a pronounced increase of 190% in the most pessimistic scenario of 80%PESS to 20% in the scenario 40%GREEN. High energy efficiency and

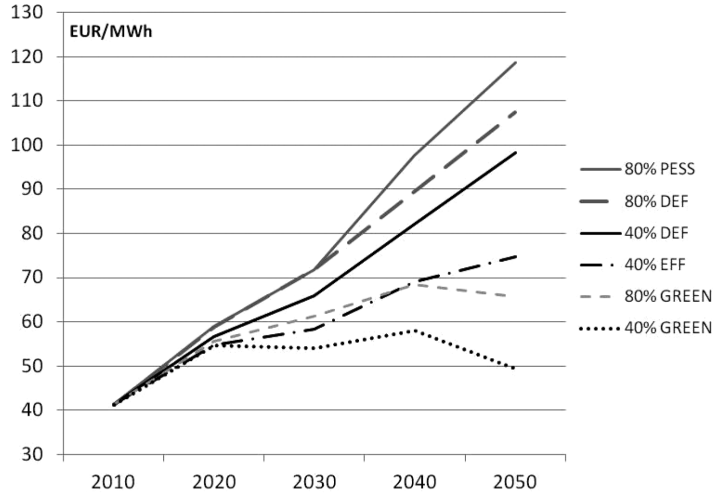

Figure 1. Wholesale electricity prices EU-27 average.

an accelerated RES roll-out in 40%GREEN alleviate price increases. As variable fuel cost of a gas-fired power station increase by about 110% until 2050 and given the reduction of plant utilization induced by RES, it follows that the profitability of a gas power station significantly reduces over time in 40%GREEN.

Between the two extreme cases, we observe an intermediate price path in scenarios with high energy efficiency and either a less ambitious climate policy (40%EFF) or a high RES roll out (80%GREEN), which lead to price increases of 81% and 59%, respectively. As of 2020, prices drift apart from the high price scenarios of 80%PESS/80%DEF/40%DEF. The high price scenarios either assume a less ambitious climate policy (40%DEF) or a combination of low increases in energy efficiency with (80% DEF) or without (80%PESS) the option of nuclear power plant construction. The difference of the latter scenarios is the wholesale price effect of newly built nuclear power plants, which amounts to 27% of the price level in the first period.

Prices in other EMF28 models differ in the way they are composed and in their type (wholesale versus end-user prices, average versus maximum prices). A rough comparison of results shows that electricity prices calculated by EMELIE-ESY are higher as compared to most other models in a variety of scenarios. The evolution of price components, namely fuel cost, carbon cost, and power plant cycling cost, systematically translates into wholesale prices in EMELIE-ESY. We observe that the link between reported power prices and cost of production is not obvious in several other EMF28 models. Prices can thus hardly be compared to wholesale prices in EMELIE-ESY. The prices reported by other models often seem to not cover full cost of investment. Instead, investment seems to be triggered even at low producer prices due to minimum capacity constraints and implicit additional revenue components. However, a pronounced electricity consumption increase in POLES and PRIMES (Fig. 4) occurs despite significant increases in the fuel and investment costs of marginal power plants, which opens up a question regarding the demand elasticity used in those models.

3.2. *Emission market prices*

Our results on emission prices under the European Union Emission Trading System (EU ETS) correlate closely with the wholesale power price developments. Notably, in the scenario 40%GREEN with a more ambitious RES roll out and less ambitious climate policy we find a decreasing price path after 2020 as laid out in Fig. 2.

The comparison of our findings with POLES and PRIMES shows that the models compute similar emission prices in the reference scenario under reference climate policy. Under reference climate policy and reference technology assumptions of scenario 40%DEF, the emission price projection of EMELIE-ESY shows a slightly more pronounced increase with an emission price of 65 EUR/t of CO_2 in 2050. To the contrary, the emission price pathways of POLES and PRIMES deviate significantly from our results in the ambitious climate policy scenario of 80%DEF. In scenarios 80%DEF, 80%PESS, and 80%GREEN, we find comparatively low emission prices with maximal values ranging between 98 and 192 EUR/t of CO_2 by 2050. In the same scenario group, POLES reports emission prices of between 240 and 3629 EUR/t of CO_2 by 2050, whereas PRIMES respective results are between 270 and 290 EUR/t of CO_2.

The range of emission prices across scenarios highlights the sensitivity of emission prices in EMELIE-ESY with regard to scenario assumptions. In particular, the difference in emission prices between scenarios 80%DEF and 80%PESS (65 EUR/t by 2050) reveals a sensitivity of the model with regard to the availability of a nuclear power option. This sensitivity lies in between that of PRIMES and POLES: The corresponding emission price reduction induced by the availability of nuclear power

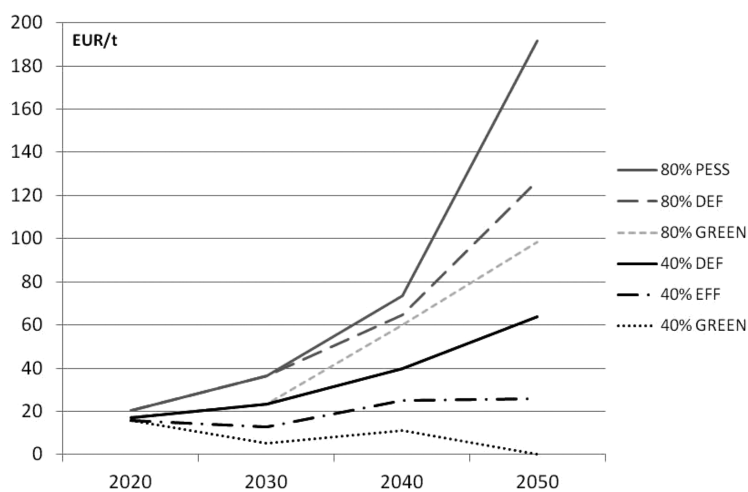

Figure 2. Carbon emission prices.

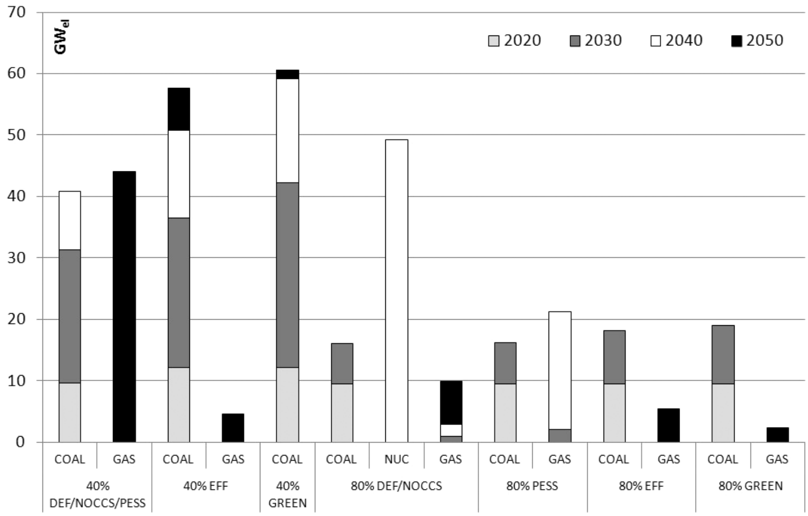

Figure 3. Conventional capacity investments until 2050 [GW_{el} net capacity].

and CCS technology is 10 EUR/t of CO_2 in the PRIMES model and 3400 EUR/t of CO_2 in POLES. Thus, comparisons of the reference cases have to be interpreted against the backdrop of much higher nuclear power plant investments in POLES.

3.3. *Market-driven capacity evolution*

Investment pathways for conventional generation technologies differ significantly across scenarios in the model EMELIE-ESY. Figure 3 gives details on aggregate investment in new conventional power plants in the EU-27. We observe identical outcomes for scenarios 40%DEF40%NOCCS/40%PESS, and for scenarios 80%DEF/80%NOCCS. As no investment into CCS technology is supported by market prices, identical outcomes are computed in the scenario pairs 40%DEF/40%NOCCS and 80%DEF/NOCCS. Furthermore, there are no investments in nuclear energy in scenario 40%DEF. It is therefore not necessary to separately consider scenarios 40%NOCCS, 40%PESS, and 80%NOCCS as they can be represented by scenarios 40%DEF, and 80%DEF. Furthermore, one can categorize the scenarios into two groups by considering overall conventional capacity investment levels until 2050. One group comprises scenarios 40%DEF to 80%DEF, where between 60 GW and 85 GW of new conventional capacities are constructed. In the second group of remaining scenarios 80%PESS to 80%GREEN only 21 GW to 37 GW of conventional technologies are incentivized by the markets. New nuclear power plants are only built in the ambitious policy scenario with low energy efficiency and less ambitious RES roll-out in 80%DEF/NOCCS. In scenario 80%DEF, the model suggests 49 GW of nuclear power plant investment. In spite of its high cost, investment into nuclear power is induced by the fact that RES investment is exogenously set whereas other options are incompatible with the emission caps. Consequently, coal fired power plant projects seem to be not

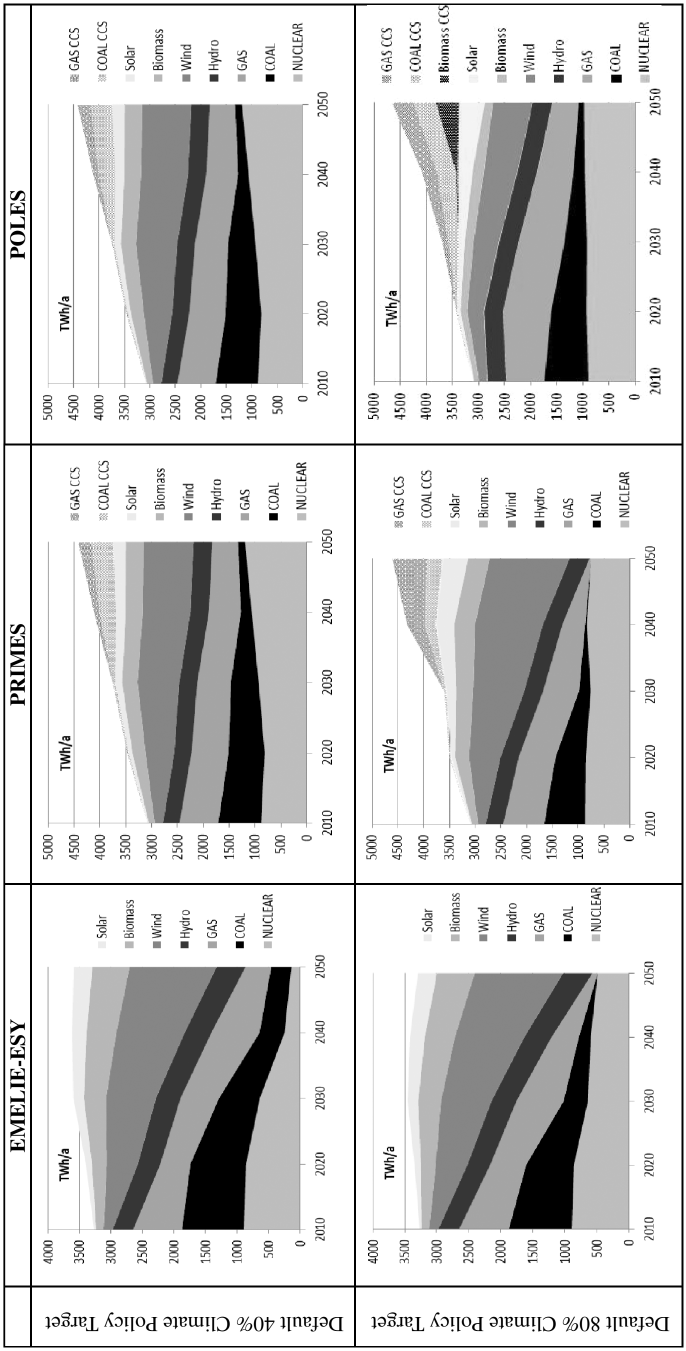

Figure 4. Power generation in the EU-27.

impacted by the availability of nuclear power technology. Comparing scenario 80% DEF to scenario 80%PESS, new built capacity reduces from 75 GW to about 38 GW.

Moreover, the scenarios of high energy efficiency suggest similar capacity developments, i.e., within pair 40%EFF/GREEN and pair 80%EFF/GREEN. Differences within these pairs are only due to the extent of power generation from RES and to the availability of nuclear power. Since the latter plays no role in the non-ambitious emission policy scenario, differences between scenario 40%EFF and 40%GREEN indicate the effect of a pronounced RES roll out and lead to minor differences in timing and technology choice between gas and coal. In scenario 40%GREEN slightly more coal fired power plants are constructed in the last model period 2050, displacing some investment in gas fired power plants. Likewise, minor differences are obtained for scenarios 80%EFF and 80%GREEN. In 80%EFF, we find investment in barely 2 GW of nuclear power. In 80%GREEN, the non-availability of nuclear investment options is partially compensated by about 1 GW higher natural gas investment.

In total, future installed capacities in PRIMES and POLES are significantly higher than in EMELIE-ESY although RES input is relatively similar across all models. Most notably, PRIMES and POLES set themselves apart from EMELIE-ESY in that they are comparatively optimistic on the deployment of CCS technology for both, gas and coal power plants. PRIMES projects for both scenarios 40%DEF and 80%DEF around 50 GW to 60 GW of CCS-equipped coal-fired power plants in the EU by 2050. Moreover, PRIMES calculates investments into Gas CCS power plants of around 142 GW in the stringent climate policy scenario 80%DEF and 41 GW in the 40%DEF scenario by 2050, respectively. Emission prices of the EU ETS as well as the development of electricity consumption can partly explain these differences.

Similarly, installed nuclear power plant capacity by the year 2050 differs significantly across the compared models. Whereas EMELIE-ESY calculates an installed capacity of 21 GW in scenario 40%DEF, and 72 GW under stringent climate policy, the respective values range between 102 GW and 156 GW in PRIMES and POLES. Two drivers of these differences can be identified: First and foremost, the investment costs of nuclear power plants is up to 50% lower in POLES, and up to 25% lower in PRIMES, notably in the early periods of the time horizon. Adding to this, variable cost of 25 EUR/MWh for nuclear power are higher in EMELIE-ESY than in any other model. Secondly, the demand development in EMELIE-ESY is dampened by high prices, whereas other models, e.g., PRIMES and POLES, project an escalating consumption of electricity.

We observe very low newly built conventional capacity investments in our model in the scenarios of ambitious climate policy without the option of nuclear energy (80% PESS/80%EFF/80%GREEN). We shall stress at this point that our model does not *per se* provide sufficient capacities to meet system reliability or adequacy but it represents an "energy-only" market. Investors must recoup their investment cost by the pure sales of energy without generating any additional revenues from other services (i.e., no capacity payments, no ancillary services). We presume that system requirements are likely to be fulfilled by cheap single cycle gas turbines and stronger network integration in Europe besides the contribution of storage and demand-side measures to lowering peak load.

Overall, the results of the EMELIE-ESY model indicate that even a low-carbon EU is likely to see relatively little private investor engagement in coal-fired and new gas-fired plants and particularly in CCS technology and nuclear power plants under the specified assumptions of RES capacity expansion and feed-in profiles. This holds even though market prices continue to rise steadily in most countries. Besides the effect of overall demand growth as key driver of investment, we explain the low investment level by implicit assumptions regarding investment incentives. Investment behavior in the EMELIE-ESY model is market-driven assuming the current market design without capacity instruments and system stability policies. By contrast, these policies can be regarded as crucial for the induction of capacity investments in the compared models, since the corresponding prices can hardly support an assumed discount rate of private investment returns of at least 8% (Capros, 2011, p. 26; EC, 2011, p. 73). Note that our model EMELIE-ESY considers the current market design of marginal-cost-based wholesale markets to remain in place even in a future system with RES dominance. In the current model set-up, we are not able to reflect the increasing role of balancing and reserve power markets or capacity markets as source of income to private investors. Our results can therefore only be taken as indication to future developments under today's rules.

3.4. *Power consumption and generation mix*

An important determinant of the market developments and a major explanation for the observed deviations in the results of our model comparison is the development of electricity consumption. The evolution of net power generation, i.e., final consumption including network losses, is shown in Fig. 4 for the two climate policy scenarios 40%DEF and 80%DEF. Clearly, the price increases in EMELIE-ESY induce only a modestly increasing or even stagnant development in consumption, although reference demand grows significantly over the time horizon. Taking into account price and demand effects, we obtain a 10% increase until 2050 in scenario 40%DEF. In scenario 80%DEF, we observe an increase until 2030 and a modest decrease afterwards. Quite differently, the two models used for comparison report consumption growth rates between 44 and 48% compared to the base year 2010, largely unaffected by the stringency of climate policy and the corresponding high carbon emission prices of 240-270 EUR/t in scenario 80%DEF.

Figure 4 also entails power generation by source. For the less ambitious policy scenario 40%DEF, a fading significance of nuclear power generation in the EU is demonstrated in EMELIE-ESY. Starting with a share in power generation of 27% in 2010, nuclear energy reaches 24% in 2020 and diminishes to a 4% share by 2050. The most important electricity source by 2050 is wind power, followed by biomass and hydro power. Gas power production reduces over time but replaces coal in its position as dominant fossil fuel. Whereas the 2010 reference power mix is similar in PRIMES and EMELIE-ESY, there is a significantly different evolution until 2050. The PRIMES model projects a much larger generation of conventional power plants in absolute terms. By 2050, PRIMES projects for the 40%DEF scenario all conventional power sources to exceed 50% of the EU's power production, with nuclear power as dominant source (27%). PRIMES' share of RES production of 45% by 2050 contrasts with 76% in EMELIE-ESY. This difference is mainly due to the 27% higher power consumption in PRIMES (4545 TWh/year) compared to EMELIE-ESY (3592 TWh/year).

Under the more ambitious climate policy targets of scenario 80%DEF, the role of RES gains dominant importance with a production share of 83% by 2050 in EMELIE-ESY. The assumed growth of RES corresponds with a reduction of nuclear power to a 15% share, and an almost complete cutback of fossil fuel usage. Natural gas fired power production keeps merely a 2% share in power generation, whereas coal-fired power production declines completely. The absence of coal power production arises despite significant coal-fired production capacities not reaching their full lifetime by 2050. Accordingly, gas-fuelled powered plants reach only a low rate of utilization, and coal-fired power plants are not able to recover fuel and emission costs through electricity prices in the last period. Reduced utilization rates and increasing emission and fuel prices are also a major obstacle for CCS technology investments as modeled in EMELIE-ESY. Since emission rates of CCS are not irrelevant under CO_2 prices of over 100 EUR/t and as high capital costs of CCS gain importance under low utilization rates, levelized costs of CCS are escalating. Under a moderate price elasticity of -0.3, the model suggests that the demand is reduced rather than new CCS power plants being built.

These findings contrast with the picture drawn by the models PRIMES and POLES, where fossil fuels keep a significant share in power generation even in a world of ambitious climate policy. POLES calculates a 36% share of fossil fuelled power plants in power generation by 2050 in 80%DEF, whereas PRIMES projects a corresponding 27% share. Finally, PRIMES projects a share of nuclear energy of 20%, and POLES finds a quarter of European electricity generation produced by nuclear power in the year 2050 for scenario 80%DEF. Given increasing electricity generation, PRIMES finds a 10% decrease of nuclear power generation compared to 2010 production, whereas the model POLES computes an increase of about 10% with a generation of 985 TWh in 2050.

4. Conclusion

We have assessed the potential impacts of different climate policy regimes on electricity prices, CO_2 prices and generation capacity investment within the EMF 28 framework. The results of EMELIE-ESY suggest that climate targets can be met by the power sector without investment into CCS for the given RES roll-out according to

NREAP projections. Moreover, investment into new nuclear power plants is expected only in a stringent climate policy scenario and conditional on the absence of the option to replace it with additional RES capacity. Our findings contrast with results from the peer models PRIMES and POLES.

Differences are explained by our assumptions regarding technology costs, high electricity prices, and the use of a significant price elasticity of electricity demand. Based on latest assessments, we assume higher capital and variable generation costs for nuclear and CCS power plants compared to PRIMES and POLES. This assumption leaves room for potentially high electricity prices without an induction of additional investments. Additionally, we find a low level of new non-RES capacity investment due to increasing prices of fossil fuels and CO_2. These factors give rise to a pronounced increase of wholesale spot market prices found by EMELIE-ESY. These price increases on the wholesale market exert downward pressure on overall power demand. By contrast, PRIMES and POLES report a comparatively stable increase of electricity consumption by 2050, despite high emission prices. All in all, our findings suggest that the projected growth of RES supply can sufficiently meet electricity consumption complemented by only few capacity investments in conventional technology. This comes at the price of rising power prices which contain demand growth.

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