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Abstract: This paper gives a detailed mathematical description of LIBEMOD, which as an economic computable equilibrium model for the Western European natural gas and electricity markets. The model assumes that all markets are competitive both in the short run and in the long run. The paper also contains detailed information on the data sources used in order to calibrate the model.

Keywords: Liberalisation, energy, simulations

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1. Introduction

LIBEMOD as an economic computable equilibrium model for the Western European natural gas and electricity markets. The model assumes that all markets are competitive. In addition to the natural gas and electricity markets in Western Europe, these are the world markets for crude coal and oil and the markets for transportation of energy goods. Hence, the model operates with four energy goods (coal, natural gas, oil and electricity) that are produced, traded and consumed in each of the 13 model countries (Austria, Belgium [including Luxembourg], Denmark, Finland, France, Germany, Great Britain, Italy, Netherlands, Norway, Spain, Sweden and Switzerland). In addition, there is production and consumption of energy (coal and oil) in exogenous countries (group of other OECD countries, Algeria, Russia, group of signatory countries to the Kyoto agreement not listed earlier, group of remaining countries). While fossil fuels are traded in annual markets, electricity is traded in period markets (summer vs. winter, daytime vs. night) because power cannot be stored (except in limited-capacity hydro-reservoir). In each model country, there are a number of technologies (coal power, gas power, oil power, nuclear, pumped storage hydro, reservoir hydro, waste power and renewable) available for supplying electricity. Finally, we distinguish between the short run version of the model and the long-run version. In the short run version capacities in international transmission of natural gas and electricity, as well as capacities in power production, are given. These capacities are determined in the long-run version of the model.

Below we give a technical documentation of the model. First we define the symbols used in the short-run verson. Next we provide a mathematical description of the equations encompassing the short-run model. Finally, we explain the extension of the short-run model to the long-run model.

2. Short Run Model - Notation

For each symbol, indexes are in small letters, and can appear as both subscripts and superscripts.

Superscripts in capital letters do not denote indexes, but a separate variable.

Table 1: Sets - short run model

Symbol	Name	Content
M	Countries	$M^N \cup M^X \cup M^W$
M^N	Endogenous countries	at,be,ch,fi,de,dk,es,fr,gb,it,nl,no,se
M^X	Exogenous countries	ru
M^W	Rest of World	al,c1,roecd,rw
L	Electricity technologies	$L^T \cup L^S$
L^T	Transforming technologies	gaspower, coalpower, oilpower, pumped
L^S	Special technologies	reservoir, nuclear, CRW, GSW
L^G	Endogenous technologies	gaspower, coalpower, oilpower, pumped, reservoir, nuclear, CRW
T	Time periods	summernight, summerday, winternight, winterday
S	Seasons	summer, winter
TS	Period-season Correspondance	summernight.summer, summerday.summer, winternight.winter, winterday.winter
T_s	Season to period mapping	$\{t \in T \| (t,s) \in TS\}$
J	Energy types	$J^E \cup J^F$
J^E	Electricity	Electricity
J^F	Fossil fuels	$J^G \cup J^W$
J^G	Gas	Gas
J^W	World traded fuels	coal, oil
LJ	Technology-fuel correspondance	pumped.electricity, gaspower.gas, coalpower.coal, oilpower.oil
J_l	Technology to fuel mapping	$\{j \in J \| (l,j) \in LJ\}$
L_j	Fuel to technology mapping	$\{l \in L^T \| (l,j) \in LJ\}$
MM^E	Unique country pairs with electricity transmission	$\left\{(m,n) \in M \times M \,\middle\|\, \begin{array}{l} m \text{ and } n \text{ have existing or potential} \\ \text{electricity transmission lines, } m > n \end{array}\right\}$
MM^G	Unique country pairs with gas transmission	$\left\{(m,n) \in M \times M \,\middle\|\, \begin{array}{l} m \text{ and } n \text{ have existing or} \\ \text{potential pipelines, } m > n \end{array}\right\}$

Symbol	Name	Content
Q	Consumers	$Q^P \cup Q^E$
Q^P	Private consumers	households, industry
Q^E	Intermediate demand	electricity producers
D^O	Nodes in demand tree	$D^K \cup D^C \cup D^P$
D^K	Nests	T,R,RE,RG,RC,RO, EL,SU,WI
D^C	Model final commodities	GA,CO,OI,SN,SD,WN,WD
D^P	Exogenous final commodities	P,PE,PG,PC,PO
D^G	Goods in demand tree	$D^O - \{'\mathrm{T}'\}$
D^{CJ}	Annual fuel demand correspondence	GA.gas,CO.coal,OI.oil
D^{CT}	Period electricity demand correspondence	SN.summernight, SD.summerday, WN.winternight, WD.winterday
D^N	Nest - good correspondence (CES tree)	T.(P,R), R.(Re,Rg,Rc,Ro), Re.(Pe,EL), Rg.(Pg,GA), Rc.(Pc,CO), Ro.(Po,OI), EL.(SU, WI), SU.(SN, SD), WI.(WN, WD)
D_k^N	Nest to good mapping	$\left\{g \in D^G \middle\| (k,g) \in D^N\right\}$

Table 2: Model parameters and exogenous variables – short run model

Symbol	Name	Unit	Gams name	Indices
ω_j^m	Fuel to CO_2 emission factor	$MTCO_2$/ MTOE	`omega(m,j)`	$m \in M, j \in J$
σ_j^m	Own use of fuel in extraction (share)	-	`sigma(m,j)`	$m \in M, j \in J$
ς_{jq}^m	Fuel to SO_2 emission factor	KTSO2/ MTOE	`zeta (m,j,q)`	$m \in M, j \in J, q \in Q$
os_q^m	SO2 emissions from the RAINS sectors OS1 and OS2	KTSO2	`os_em(m,q)`	$m \in M, q \in Q$
$proc^m$	SO2 emissions from the RAINS sector proc	KTSO2	`proc_em(m)`	$m \in M$
air^m	Energy consumption in air traffic (sector excluded in the RAINS model)	MTOE	`air_em(m)`	$m \in M$
ψ_t	Time in each period	kh	`psi(t)`	$t \in T$
ν_{ml}^0	Best electricity to fuel conversion factor	MTOE/ TWh	`ny0(m,l)`	$m \in M, l \in L^T$
ν_{ml}^1	Slope in electricity to fuel conversion factor function	MTOE/ (TWh* GW)	`ny1(m,l)`	$m \in M, l \in L^T$
ξ_l^m	Share of total annual time available (1 – downtime)	-	`xi(m,l)`	$m \in M, l \in L$
δ_{tu}^S	Same season day/night mapping	-	`deltaS(t,u)`	$t, u \in T$
δ_{mn}^E	Countries with electricity transmission link mapping	-	`deltaE(m,n)`	$m, n \in M$
δ_{mn}^G	Countries with gas transmission link mapping	-	`deltaG(m,n)`	$m, n \in M$
ρ_{mt}	Reserve power capacity demand	-	`rho(m,t)`	$m \in M, t \in T$
θ_{jq}^m	Loss adjustment in domestic energy distribution (1- loss share)	-	`theta(m,j,q)`	$m \in M, j \in J, q \in Q$
θ_{mn}^E	Loss adjustment in international electricity transmission (1- loss share)	-	`thetaE(m,n)`	$m, n \in M$
θ_{mn}^G	Loss adjustment in international gas transmission (1- loss share)	-	`thetaG(m,n)`	$m, n \in M$
$K_{mj}^{F\,0}$	Domestic fuel extraction capacity in base year	MTOE	`KF(m,j)`	$m \in M, j \in J^F$
$K_{ml}^{P\,0}$	Power capacity in base year	GW	`KP(m,l)`	$m \in M, l \in L$

Symbol	Name	Unit	Gams name	Indices
$K^{I\ 0}_{msl}$	Inflow (energy availability) capacity in base year	TWh	`KI(m,s,l)`	$m \in M, s \in S, l \in L$
$K^{R\,0}_{ml}$	Reservoir (energy transfer between seasons) capacity in base year	TWh	`KR(m,l)`	$m \in M, l \in L$
$K^{E\ 0}_{mn}$	International electricity transmission capacity in base year	GW	`KE(m,n)`	$m, n \in M$
$K^{G\ 0}_{mn}$	International gas transmission capacity in base year	MTOE	`KG(m,n)`	$m, n \in M$
c^{L}_{m}	Exogenous landing costs; costs of transmission of gas from production node to consumption node in same country	MUSD/ MTOE	`MCL(m)`	$m \in M$
c^{O}_{ml}	Exogenous unit operating cost in electricity production	MUSD/ TWh	`MCO(m,l)`	$m \in M, l \in L$
c^{S}_{ml}	Exogenous unit startup cost in electricity production	MUSD/ GW	`MCS(m,l)`	$m \in M, l \in L$
c^{M}_{ml}	Exogenous unit maintenance cost in electricity production	MUSD/ GW	`MCM(m,l)`	$m \in M, l \in L$
c^{E}_{mm}	Exogenous marginal cost in international electricity transmission	MUSD/ TWh	`MCE(m,m)`	$m, n \in M$
c^{G}_{mn}	Exogenous marginal cost in international gas transmission	MUSD/ MTOE	`MCG(m,n)`	$m, n \in M$
d^{m}_{jq}	Distribution unit cost, excluding cost of loss	MUSD/ (TWh or MTOE)	`d(m,j,q)`	$m \in M, j \in J, q \in Q^{P}$
κ^{m}_{jq}	CO_2 tax	MUSD/ $MTCO_2$	`kappa(m,j,q)`	$m \in M, j \in J, q \in Q$
ε^{m}_{jq}	Energy tax	MUSD/ (TWh or MTOE)	`Epsilon(m,j,q)`	$m \in M, j \in J, q \in Q$
χ^{m}_{jq}	SO2 tax	MUSD/ KTSO2	`Chi(m,j,q)`	$m \in M, j \in J, q \in Q$
τ^{m}_{jq}	Value added tax rate	-	`Tau(m,j,q)`	$m \in M, j \in J, q \in Q$
ac_{mj}	Constant in marginal cost function for extraction	TWh or MTOE	`ac(m,j)`	$m \in M, j \in J$
bc_{mj}	Slope in marginal cost function for extraction	-	`bc(m,j)`	$m \in M, j \in J$
a^{X}_{mj}	Constant in linear demand for fuel at world market	MTOE	`ax(m,j)`	$m \in M^{X} \cup M^{W}, j \in J^{W}$

Symbol	Name	Unit	Gams name	Indices
b_{mj}^{X}	Price coefficient in demand for fuel at world market	-	`bx(m,j)`	$m \in M^X \bigcup M^W, j \in J^W$
$V_{mq}^{D\ 0}$	Demand income level in base year	-	`dV0(m,q)`	$m \in M, q \in Q$
σ_{mqk}^{D}	Demand substitution parameter	-	`dsigma(m,q,k)`	$m \in M, q \in Q, k \in D^K$
a_{mqg}^{D}	Demand share parameter	-	`da(m,q,g)`	$m \in M, q \in Q, g \in D^G$
$\overline{x}_{mqo}^{D}$	Demand endowment parameter	-	`dXbar(m,q,o)`	$m \in M, q \in Q, c \in D^{CJ}$

Table 3: Model endogenous variables – short run model

Symbol	Name	Unit	Gams name	Indices
x^{E}_{mtq}	Period electricity demand	TWh	`Xe(m,t,q)`	$m \in M, t \in T, q \in Q$
x^{m}_{jq}	Annual energy demand	TWh or MTOE	`X(m,j,q)`	$m \in M, j \in J, q \in Q$
x_oth_{mj}	Demand for oil and coal at the world market	MTOE	`X_oth(m,j)`	$m \in M^{X} \bigcup M^{W}, j \in J^{W}$
y^{E}_{mtl}	Period electricity supply	TWh	`Ye(m,t,l)`	$m \in M, t \in T, l \in L$
y^{m}_{j}	Annual energy supply	TWh or MTOE	`Y(m,j)`	$m \in M, j \in J$
z^{E}_{mnt}	Period electricity imported (from m to n)	TWh	`Ze(m,n,t)`	$m, n \in M, t \in T$
z^{G}_{mn}	Annual gas imported (from m to n)	MTOE	`Zg(m,n)`	$m, n \in M$
z^{j}_{m}	Net total imports of energy	TWh or MTOE	`Z(m,j)`	$m \in M, j \in J$
P^{XE}_{mtq}	Period electricity user price	MUSD/ TWh	`Pxe(m,t,q)`	$m \in M, t \in T, q \in Q$
P^{X}_{mjq}	Annual energy user price	MUSD/ (TWh or MTOE)	`Px(m,j,q)`	$m \in M, j \in J, q \in Q$
P^{YE}_{mt}	Period electricity supply price	MUSD/ TWh	`Pye(m,t)`	$m \in M, t \in T$
P^{Y}_{mj}	Annual energy supply price	MUSD/ (TWh or MTOE)	`Py(m,j)`	$m \in M, j \in J$
P^{W}_{j}	World market annual energy price	MUSD/ MTOE	`Pw(j)`	$j \in J^{W}$
K^{PM}_{ml}	Maintained power capacity	GW	`KPM(m,l)`	$m \in M, l \in L$
K^{PR}_{mtl}	Reserve power capacity	GW	`KPr(m,t,l)`	$m \in M, t \in T, l \in L$
K^{PS}_{mtl}	Startup power capacity in excess of other period in season	GW	`KPS(m,t,l)`	$m \in M, t \in T, l \in L$
ν^{m}_{tl}	Marginal electricity to fuel conversion factor	MTOE/ TWh	`ny(m,t,l)`	$m \in M, t \in T, l \in L$
$\bar{\nu}^{m}_{tl}$	Average electricity to fuel conversion factor	MTOE/ TWh	`nybar(m,t,l)`	$m \in M, t \in T, l \in L$
c^{p}_{mtl}	Marginal direct costs in electricity production	MUSD/ TWh	`MCP(m,t,l)`	$m \in M, t \in T, l \in L$
CO^{m}_{2}	CO_2 emissions	$MTCO_2$	`CO2(m)`	$m \in M$
SO^{m}_{2}	SO_2 emissions	$KTSO_2$	`SO2(m)`	$m \in M$
R^{m}_{sl}	Reservoir filling at end of season	TWh	`R(m,s,l)`	$m \in M, s \in S$ $l = 'reservoir'$

Symbol	Name	Unit	Gams name	Indices
λ^{E}_{ml}	Shadow price power capacity	MUSD/ GW	`lambdaE(m, l)`	$m \in M, l \in L$
λ^{F}_{mj}	Shadow price annual energy capacity	MUSD/ MTOE	`lambdaF(m,j)`	$m \in M, j \in J^{F}$
α_{msl}	Shadow price inflow capacity	MUSD/ TWh	`alpha(m,s,l)`	$m \in M, s \in S, l \in L$
β_{msl}	Shadow price reservoir capacity	MUSD/ TWh	`beta(m,s,l)`	$m \in M, s \in S$ $l = 'reservoir'$
η_{ml}	Shadow price annual availability constraint	MUSD/ TWh	`eta(m,l)`	$m \in M, l \in L$
ϕ_{mtl}	Shadow price startup day-night constraint	MUSD/ GW	`fi(m,t,l)`	$m \in M, t \in T, l \in L$
μ^{M}_{mtl}	Shadow price maintained periodic electricity capacity	MUSD/ TWh	`myM(m,t,l)`	$m \in M, t \in T, l \in L$
μ^{E}_{mnt}	Shadow price international electricity transmission capacity	MUSD/ TWh	`myE(m,n,t)`	$m, n \in M, t \in T$
μ^{G}_{mn}	Shadow price international gas transmission capacity	MUSD/ MTOE	`myG(m,n)`	$m, n \in M$
P^{KPR}_{mt}	Price of reserve power capacity	MUSD/ GW	`PKPr(m,t)`	$m \in M, t \in T$
x^{D}_{mqo}	Utility level	-	`dX(m,q,o)`	$m \in M, q \in Q, o \in D^{O}$
p^{D}_{mqo}	Price index	-	`dP(m,q,o)`	$m \in M, q \in Q, o \in D^{O}$

3. Short Run Model – Core Relations

3.1 Markets

The model consists of a set M^N of endogenous countries with markets for the set J of the energy types coal, oil, gas and electricity. For electricity, there is a set of periods T, with different supply and demand characteristics. For the annual gas commodity and the period electricity commodities, there is international trade constrained by transmission capacities. In addition to the endogenous countries there are exogenous countries M^X which have a net supply of gas and period electricity to the endogenous countries, but have no endogenous modelling of demand behaviour. The markets for coal and oil are world markets. Finally, both exogenous countries and the remaining countries M^W supply and demand coal and oil.

3.2 Fossil Fuel Supply

Natural gas

There is a domestic supplier/producer of natural gas in each endogenous country $m \in M^N$ and in each exogenous country $m \in M^X$. The natural gas suppliers have a variable cost function of the form:

$$C^F_{mj} = ac_{mj} y^m_j + \frac{bc_{mj}}{2} y^m_j y^m_j - dc_{mj} K^{F\,0}_{mj} (1 - \frac{y^m_j}{K^{F\,0}_{mj}}) \ln(1 - \frac{y^m_j}{K^{F\,0}_{mj}}) - dc_{mj} y^m_j, \quad m \in M^N \cup M^X, j \in J^G \tag{1}$$

where y^m_j is the quantity supplied, ac_{mj}, bc_{mj} and dc_{mj} are cost coefficients, and $K^{F\,0}_{mj}$ is the available domestic capacity. Production is however constrained by the available domestic capacity:

$$y^m_j \leq K^{F\,0}_{mj}, m \in M^N, j \in J^G \tag{2}$$

Operating surplus (short-run profits) are given by:

$$\Pi^m_j = P^Y_{mj} y^m_j - C^F_{mj} - c^L_m y^m_j, \, m \in M^N, j \in J^G \tag{3}$$

where P_{mj}^{Y} is the producer price and c_{m}^{L} is the costs of transmission of natural gas from the production node to the consumption node in the same country . Formulating the profit maximisation as a Kuhn-Tucker optimisation problem, one can form the Lagrangian from (3), inserting (1) and constrained by (2):

$$\mathrm{L}_{j}^{m} = P_{mj}^{Y} y_{j}^{m} - C_{mj}^{F} - c_{m}^{L} y_{j}^{m} - \lambda_{mj}^{F} \left\{ y_{j}^{m} - K_{mj}^{F\,0} \right\}, m \in M^{N}, j \in J^{G} \tag{4}$$

The first order necessary conditions for the maximisation of (3) subject to (2) is then

$$\begin{aligned} P_{mj}^{Y} - ac_{mj} - bc_{mj} y_{j}^{m} - dc_{mj} \ln(1 - \tfrac{y_{j}^{m}}{K_{mj}^{F\,0}}) - c_{m}^{L} - \lambda_{mj}^{F} \leq 0 \perp \; y_{j}^{m} \geq 0, \\ m \in M^{N}, j \in J^{G} \end{aligned} \tag{5}$$

$$y_{j}^{m} - K_{mj}^{F\,0} \leq 0 \perp \; \lambda_{mj}^{F} \geq 0, m \in M^{N}, j \in J^{G} \tag{6}$$

where $a \leq 0 \perp b \geq 0$ is shorthand for the complementarity slackness conditions $a \leq 0, b \geq 0, ab = 0$ and $a \equiv \partial \mathfrak{L} / \partial b$ [1]. Since the maximand (3) is concave and the restriction (2) is convex, (5) and (6) are also sufficient maximum conditions[2].

The exogenous countries in M^{X} are modelled by (1)-(6) for the production of gas, but with capacity equal to total exports to the endogenous countries and production costs equal to zero to ensure that all capacity is used.

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[1] In the GAMS programming language, this is best entered as "`Positive variable b`" ($b \geq 0$) in the decleration section, "`ThisEquation.. 0=G=a`" ($a \leq 0$) in the equations definition section, and "`ThisEquation.b`" ($ab = 0$) in the model definition section.

[2] For the endogenous countries, the extraction of fossil fuels is in reality set equal to capacity by setting extraction costs to zero.

Coal and oil

In each model country there is a domestic supplier/producer of coal and oil with a quadratic variable cost function of the form:

$$C^{F}_{mj} = (ac_{mj} + \tfrac{bc_{mj}}{2} y^{m}_{j}) y^{m}_{j},\ m \in M^{N}, j \in J^{W} - \tag{7}$$

Maximizing operating surplus (3) with respect to extracted quantity gives the FOCs:

$$P^{Y}_{mj} = ac_{mj} + bc_{mj} y^{m}_{j},\ m \in M^{N}, j \in J^{W} \tag{8}$$

that is, the producer price of the fuel should equal marginal costs.

3.3 Electricity Supply

Some electricity suppliers $l \in L^{T}$ transform energy inputs to electricity as described by the technical relationship

$$x^{E}_{mjtl} = \left(\nu^{0}_{ml} + \nu^{1}_{ml} \frac{y^{E}_{mtl}}{\psi_{t}} \right) y^{E}_{mtl},\ j = J_{l}, \forall m \in M^{N}, t \in T, l \in L^{T} \tag{9}$$

which is an input requirement function assumed to be quadratic giving the use of energy input *j* in country *m* in period *t* by technology *l*, as an increasing function of electricity produced[3]. This transformation is mainly from fossil fuels to electricity, but applies also to the technology 'pumped storage' which uses electricity in one period to produce electricity in another. Since there is only one fuel used in each technology, the mapping $J_{l} = \left\{ j \middle| (l,j) \in LJ \right\} \in J$ is single-valued, although the

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[3] The variable x^{E}_{mjtl} is not actually used in the model, only the sum over technologies and periods $x^{m}_{jq} = \sum_{t \in T} \sum_{l \in L_{j}} x^{E}_{mjtl}, q = \text{'electricity producers'}$, and the sum over technologies for electricity used in pumped storage $x^{E}_{mtq} = \sum_{l \in L^{P}} x^{E}_{mjtl}, j = \text{'electricity'}\ , q = \text{'electricity producers'}$.

opposite $L_j = \{l | (l,j) \in LJ\} \subset L^T$ can be many-valued. Defining $\overline{\nu}^m_{tl}$ as the average conversion factor

$$\overline{\nu}^m_{tl} = \frac{x^E_{mjtl}}{y^E_{mtl}} = \nu^0_{ml} + \nu^1_{ml} \frac{y^E_{mtl}}{\psi_t}, \; j = J_l, \forall m \in M^N, t \in T, l \in L^T \tag{10}$$

this is a linear function of used capacity, where production divided by the number of hours in period *t* is the instantanous capacity in GW. $\overline{\nu}^m_{tl}$ is the average use of input energy (MTOE for the fossil fuels) per unit electricity produced (GWh), i.e. a combination of inverse energy efficiency and a unit conversion factor. The marginal conversion rate is

$$\nu^m_{tl} = \frac{\partial (x^E_{mjtl})}{\partial y^E_{mtl}} = \nu^0_{ml} + 2\nu^1_{ml} \frac{y^E_{mtl}}{\psi_t}, \; j = J_L(l), \forall m \in M^N, t \in T, l \in L^T \tag{11}$$

representing the increase in fuel use for a marginal increase in electricity produced.

In addition to fuel costs, there are other inputs that are assumed proportionate to production, with exogenous input prices, implying a constant unit operating cost c^O_{ml}, and for technologies that do not use energy inputs in this model (L^S), this is the only cost component that depends directly on the energy production level. However, each producer is also assumed to choose the level of power capacity that is maintained, thus incurring a unit maintenance cost c^M_{ml} per unit of power (GW). Finally the producer might choose to only produce electricity in one of the periods in each season (i.e. daytime), and will then incur a daily start-up cost that in this model is expressed as a cost per start-up power capacity in each season, c^S_{ml}. Adding up the cost components, and replacing fuel input x^E_{mjtl} by (9) and (10), gives the electricity producers' variable cost equations of the form:

$$C_{ml}^{P} = \begin{cases} \sum_{t\in T}\left(c_{ml}^{O} + \overline{\nu}_{tl}^{m}P_{mjq}^{X}\right)y_{mtl}^{E} + c_{ml}^{M}K_{ml}^{PM} + \sum_{t\in T}c_{ml}^{S}K_{mlt}^{PS}, \\ \qquad j = J_l, \forall l \neq \text{pumped} \in L^T \\ \sum_{t\in T}\left(c_{ml}^{O} + \overline{\nu}_{tl}^{m}\sum_{u\in T}\delta_{tu}^{S}P_{muq}^{XE}\right)y_{mtl}^{E} + c_{ml}^{M}K_{ml}^{PM} + \sum_{t\in T}c_{ml}^{S}K_{mlt}^{PS}, \\ \qquad j = J_l, \forall l = \text{pumped} \in L^T \\ \sum_{t\in T}c_{ml}^{O}y_{mtl}^{E} + c_{ml}^{M}K_{ml}^{PM} + \sum_{t\in T}c_{ml}^{S}K_{mlt}^{PS}, \\ \qquad l \in L^S, m \in M^N, q = \text{'electricity producers'} \end{cases} \tag{12}$$

The electricity to fuel conversion factor $\overline{\nu}_{tl}^{m}$ will be nonzero only for the transforming technologies $l \in L^T$. For the fossil fuel based power producers, the unit cost includes the user price of the fuel in question corrected for the energy efficiency of the technology. For pumped storage the relevant user price is the electricity price in the other period in the same season, selected by $\delta_{tu}^{S} = 1$ if $\left\{t, u \in T_s, t \neq u\right\}$, 0 otherwise, since pumped storage producers can use electricity in one period (e.g. winter night) to pump water to their reservoir, in order to produce electricity in a different period (e.g. winter day) when prices may be higher. By assumption the reservoir in pumped storage is not of sufficient size to allow storing between seasons, and the selection variable is only 1 between periods in the same season.

The marginal fuel and operating cost is given by

$$\frac{\partial C_{ml}^{P}}{\partial y_{mtl}^{E}} = c_{mtl}^{P} = \begin{cases} c_{ml}^{O} + \nu_{tl}^{m}P_{mjq}^{X},\ j = J_l,\ \forall l \neq \text{'pumped storage'} \in L^T \\ c_{ml}^{O} + \nu_{tl}^{m}\sum_{u\in T}\delta_{tu}^{S}P_{muq}^{XE},\ \forall l = \text{'pumped storage'} \in L^T \\ c_{ml}^{O}, \forall l \in L^S \end{cases} \tag{13}$$
$$m \in M^N, q = \text{'electricity producers'}$$

but this only reflects those cost components that are directly influenced by energy production.

Operating surplus (short-run profits) are given by:

$$\Pi_{ml}^{E} = \sum_{t\in T}P_{mt}^{YE}y_{mtl}^{E} - C_{ml}^{P},\ m \in M^N, l \in L \tag{14}$$

which we assume are the objective functions of each electricity producer. In general the solution of a Kuhn-Tucker optimisation problem returns the restrictions on the original problem complementary to an associated multiplier, cf (2) and (6). To shorten the exposition from this point onwards, restrictions on the optimisation problem are only given in solution form, where the Kuhn-Tucker multiplier complementary to each constraint is also indicated.

Firstly, the maintained power capacity is constrained to be less or equal to the total installed power capacity.

$$K_{ml}^{PM} \leq K_{ml}^{P\,0} \perp \lambda_{ml}^{E} \geq 0,\, m \in M^N, l \in L^G \tag{15}$$

Secondly, in each time period production of electricity is constrained by the maintained capacity, net of any capacity sold as reserve capacity to the system operator, K_{mtl}^{PR}. The power capacity in GW is transformed to electricity production capacity in TWh by multiplying by the number of hours in each period:

$$y_{mtl}^{E} \leq \psi_t (K_{ml}^{PM} - K_{mtl}^{PR}) \perp \mu_{mtl}^{M} \geq 0,\, m \in M^N, t \in T, l \in L^G \tag{16}$$

All power plants need some down-time for technical maintenance, so the total annual usage must be constrained to be less than the maintained instantanous capacity by an availability factor:

$$\sum_{t \in T} y_{mtl}^{E} \leq \xi_l^m \sum_{t \in T} \psi_t K_{ml}^{PM} \perp \eta_{ml} \geq 0,\, m \in M^N, l \in L^G \tag{17}$$

Finally, the difference between capacity use in one period and the other period in the same season is constrained by the capacity that is started each day in that season, in principle a symmetric condition, but which in general will only bind for the daytime period:

$$y_{mtl}^{E} / \psi_t - \sum_{u \in T} \delta_{tu}^{S}\, y_{mul}^{E} / \psi_u \leq K_{mtl}^{PS} \perp \phi_{mtl} \geq 0,\, m \in M^N, \quad t \in T, l \in L^G \tag{18}$$

where again the selector δ_{tu}^{S} is one for the other period *u* in the same season as period *t*, and zero for all other periods. For each pair of periods in the same seasons there are thus two inequalities, which together imply two different non-negative start-up capacities where only (at most) one will be non-zero in a given equilibrium. In nuclear power plants, the time and costs it takes to start up and shut down makes it infeasible to vary the used capacity between day to night within a season, so the start-up capacity is exogenously set at zero.

Hydro power producers, except pumped storage, have additionally restrictions based on the total seasonal inflow capacity expressed in energy units, and on the reservoir capacity used for transferring energy between seasons:

$$\sum_{t \in T_s} y^E_{mtl} + R^m_{sl} - R^m_{s-1,l} \le K^{I\ 0}_{msl} \perp \alpha_{msl} \ge 0, m \in M^N, s \in S, l = \text{'reservoir'} \qquad (19)$$

$$R^m_{sl} \le K^{R\,0}_{ml} \perp \beta_{ms} \ge 0, m \in M^N, s \in S, l = \text{'reservoir'} \qquad (20)$$

Where R^m_s is the reservoir filling at the end of season *s*, and T_s is the set of periods that fall in season s.

A similar formulation is also used for the Combined Renewables and Waste (CRW) technology, where production in each season is constrained by the available waste in that season measured in energy units, i.e. implicitly assuming zero reservoir size:

$$\sum_{t \in T_s} y^E_{mtl} \le K^{I\ 0}_{msl} \perp \alpha_{msl} \ge 0, m \in M^N, l = \mathrm{CRW}, s \in S \qquad (21)$$

The Geothermal, Solar and Wind (GSW) technology has varying available energy capacity for each period, and no storage possibilities, so production in each period is fully exogenous.

For the transforming technologies (all except reservoir, CRW, GSW and nuclear) one can find profit maximistion behaviour from the Lagrangian formed from maximizing (14) subject to (15), (16), (17) and (18):

$$\mathrm{L}_{ml}^{E} = \sum_{t\in T}\left(P_{mt}^{YE} y_{mtl}^{E} + P_{mt}^{KPR} K_{mtl}^{PR}\right) - C_{mk}^{P} - \lambda_{ml}^{E}\left\{K_{ml}^{PM} - K_{ml}^{P\,0}\right\}$$
$$-\sum_{t\in T}\mu_{mtl}^{M}\left\{y_{mtl}^{E} - \psi_{t}\left(K_{ml}^{PM} - K_{ml}^{PR}\right)\right\} - \eta_{ml}\left\{\sum_{t\in T} y_{mtl}^{E} - \xi_{l}^{m}\sum_{t\in T}\psi_{t} K_{ml}^{PM}\right\} \tag{22}$$
$$-\sum_{t\in T}\phi_{mtl}\left\{ y_{mtl}^{E}/\psi_{t} - \sum_{u\in T}\delta_{tu}^{S}\, y_{mul}^{E}/\psi_{u} - K_{mtl}^{PS}\right\},\ m\in M^{N}, l\in L^{T}$$

which in addition to the restrictions and the associated complementarity conditions has FOCs with respect to produced electricity in each period:

$$P_{mt}^{YE} - c_{mtl}^{P} - \mu_{mtl}^{M} - \eta_{ml} - \left(\phi_{mtl}/\psi_{t} - \sum_{u\in T}\delta_{tu}^{S}\,\phi_{mul}/\psi_{u}\right) \le 0 \perp y_{mtl}^{E} \ge 0,$$
$$m\in M^{N}, t\in T, l\in L^{T} \tag{23}$$

The FOC with respect to the sale of reserve capacity is

$$P_{mt}^{KPR} - \mu_{mtl}^{M}\psi_{t} \le 0 \perp K_{mtl}^{PR} \ge 0,\ m\in M^{N}, t\in T, l\in L^{T} \tag{24}$$

Further the FOC with respect to the maintained capacity is

$$\sum_{t\in T}\psi_{t}\left\{\mu_{mtl}^{M} + \eta_{ml}\xi_{l}^{m}\right\} \le c_{ml}^{M} + \lambda_{ml}^{E} \perp K_{ml}^{PM},\ m\in M^{N}, l\in L^{T} \tag{25}$$

and the FOC with respect to the start-up capacity is

$$\phi_{mtl} \le c_{ml}^{S} \perp K_{mtl}^{PS},\ m\in M^{N}, t\in T, l\in L^{T} \tag{26}$$

The Nuclear electricity producing technology is assumed to have prohibitive startup costs, and are therefore modelled with $K_{mtl}^{PS} = 0$ exogenously in (18) so that capacity use is constrained to be equal during day and night. Not optimising with respect to K_{mtl}^{PS}, the nuclear FOCs do not include (26), but are otherwise identical to the FOCs for the transforming technologies above.

For the Hydroelectric reservoir technology, the optimisation problem involves two extra restrictions and one extra choice variable:

$$
\begin{aligned}
\mathrm{L}_{ml}^{E} = & \sum_{t\in T}\left(P_{mt}^{YE} y_{mtl}^{E} + P_{mt}^{KPR} K_{mtl}^{PR}\right) - C_{mk}^{P} - \lambda_{ml}^{E}\left\{K_{ml}^{PM} - K_{ml}^{P\,0}\right\} \\
& -\sum_{t\in T}\mu_{mtl}^{M}\left\{y_{mtl}^{E} - \psi_{t}\left(K_{ml}^{PM} - K_{ml}^{PR}\right)\right\} - \eta_{ml}\left\{\sum_{t\in T} y_{mtl}^{E} - \xi_{l}^{m}\sum_{t\in T}\psi_{t} K_{ml}^{PM}\right\} \\
& -\sum_{t\in T}\phi_{mtl}\left\{ y_{mtl}^{E} \big/ \psi_{t} - \sum_{u\in T}\delta_{tu}^{S}\, y_{mul}^{E} \big/ \psi_{u} - K_{mtl}^{PS}\right\} \\
& -\sum_{s\in S}\alpha_{msl}\left\{\sum_{t\in T_s} y_{mtl}^{E} + R_{sl}^{m} - R_{s-1,l}^{m} - K_{msl}^{I\,0}\right\} \\
& -\sum_{s\in S}\beta_{ms}\left\{R_{sl}^{m} - K_{m}^{R0}\right\},\ m\in M^{N}, l = \text{'reservoir'}
\end{aligned}
\tag{27}
$$

which in addition to the restrictions (15), (16), (17), (18), (19) and (20), and the associated complementarity conditions has FOCs:

$$
\begin{gathered}
P_{mt}^{YE} - c_{mtl}^{P} - \mu_{mtl}^{M} - \eta_{ml} - \left(\phi_{mtl} \big/ \psi_{t} - \sum_{u\in T}\delta_{tu}^{S}\, \phi_{mul} \big/ \psi_{u}\right) - \alpha_{msl} \leq 0 \perp y_{mtl}^{E} \geq 0, \\
m\in M^{N}, t\in T, l = \text{'reservoir'}
\end{gathered}
\tag{28}
$$

$$
\alpha_{m,s+1,l} \leq \alpha_{msl} + \beta_{ms} \perp R_{s}^{m} \geq 0, m\in M^{N}, l = \text{'reservoir'}, s\in S \tag{29}
$$

and again (25) and (26).

Forming Lagrangians in a similar manner for the CRW technology, in addition to recovering the same restrictions and FOCs respectively as for the general case, instead of (23) the FOC with respect to produced electricity is:

$$
\begin{gathered}
P_{mt}^{YE} - c_{mtl}^{P} - \mu_{mtl}^{M} - \eta_{ml} - \left(\phi_{mtl} \big/ \psi_{t} - \sum_{u\in T}\delta_{tu}^{S}\, \phi_{mul} \big/ \psi_{u}\right) - \alpha_{msl} \leq 0 \perp y_{mtl}^{E} \geq 0, \\
m\in M^{N}, t\in T, l = \text{'CRW'}
\end{gathered}
\tag{30}
$$

which can be seen to be identical in form to (28).

3.4 Demand

Each private consumer $q \in Q^P$ in each endogenous country $m \in M^N$ has a utility level x_{mqT}^D, which is the quantity level of the top node in a CES utility tree. Each node $o \in D^O$ in a CES utility tree is either a nest $k \in D^K$ or a commodity $c \in D^C \bigcup D^P$. In a multilevel CES tree a nest can comprise both commodities and subnests, which collectively can be termed goods $g \in D^G$, and the top node 'T' is the only nest that is not also a good. Each nest is a function of its goods, with one substitution parameter σ_{mqk}^D and a share parameter a_{mqg}^D for each good :

$$x_{mqk}^D = \left[\sum_{g \in D_k^N} a_{mqg}^{D\ \frac{1}{\sigma_{mqk}^D}} x_{mqg}^{D\ \frac{1-\sigma_{mqk}^D}{\sigma_{mqk}^D}} \right]^{\frac{\sigma_{mqk}^D}{1-\sigma_{mqk}^D}}, \ \forall m \in M^N, q \in Q^P, k \in D^K \tag{31}$$

The chosen nest structure allows for limited substitution possibilities between electricity at day and night in each season, and between seasons. Each energy good (EL,GA,CO,OI) enters in a (generally complementary) nest (RE,RG,RC,RO) with energy-using goods (PE,PG,PC,PO) such as cookers, heaters, appliances etc. These energy nests have substitution possibilities within a general energy nest R, which enters in the top nest along with a general other commodity P. The complementary goods (P,PE,PG,PC,PO) do not enter the model, and are treated exogenously with prices set at 1.

The private consumers is assumed to maximize utility given a budget constraint reflecting income and commodity prices,

$$\text{Max}_{x_{mqk}^K} \ x_{mq\mathrm{T}}^D, \ s.t. \sum_{c \in D^C \bigcup D^P} p_{mqc}^D x_{mqc}^D \le V_{mq}^D, \ \forall m \in M^N, q \in Q^P \tag{32}$$

which, after inserting the nest function (31) results in an indirect utility function

$$x_{mq\mathrm{T}}^D = {V_{mq}^D}\Big/{p_{mq\mathrm{T}}^{\mathrm{D}}}, \forall m \in M^N, q \in Q^P \tag{33}$$

which is simply the income divided by the top level price index. Each nest price index is of the general form

$$p^D_{mqk} = \left[\sum_{g \in D^N_k} a^D_{mqg} P^D_{mqg}{}^{1-\sigma^D_{mqk}} \right]^{\frac{1}{1-\sigma^D_{mqk}}}, \forall m \in M^N, q \in Q^P, k \in D^K \tag{34}$$

which with the final demand prices of model and exogenous comodities,

$$\begin{aligned} p^D_{mqc} &= 1, \forall m \in M^N, q \in Q^P, c \in D^P \\ p^D_{mqc} &= P^X_{mjq}, \forall m \in M^N, q \in Q^P, (c,j) \in D^{CJ} \\ p^D_{mqc} &= P^{XE}_{mtq}, \forall m \in M^N, q \in Q^P, (c,t) \in D^{CT} \end{aligned} \tag{35}$$

completely determine all node prices. The quantity levels of goods are then given by

$$x^D_{mqg} = a^D_{mqg} \left[\frac{P^D_{mqk}}{P^D_{mqg}} \right]^{\sigma^D_{mqk}} x^D_{mqk}, \forall m \in M^N, q \in Q^P, (g,k) \in D^N \tag{36}$$

which, together with the top level quantity (i.e. utility) from (33) determine final demand for the annual energy commodities and period electricity commodities:

$$x^m_{jq} = x^D_{mqc} - \overline{x}^D_{mqc}, \forall m \in M^N, q \in Q^P, (c,j) \in D^{CJ} \tag{37}$$

$$x^E_{mtq} = x^D_{mqc} - \overline{x}^D_{mqc}, \forall m \in M^N, q \in Q^P, (c,t) \in D^{CT} \tag{38}$$

In addition to final demand, electricity producers represent intermediate demand. Based on Shephard's lemma, the demand from the electricity production sectors, conditional on a given output level, is the derivative of the cost functions (12) w.r.t. the input price, summed over these producers:

$$\begin{aligned} & x^m_{jq} = \sum_{l \in L_j} \frac{\partial C^P_{ml}}{\partial P^X_{mjE}} = \sum_{l \in L_j} \sum_{t \in T} \overline{\nu}^m_{tl} y^E_{mtl}, \\ & j \in J^F, m \in M^N, q = \text{'electricity producers'} \end{aligned} \tag{39}$$

$$\begin{aligned} & x^E_{mtq} = \sum_{l \in L_j} \frac{\partial C^P_{ml}}{\partial P^{XE}_{mtq}} = \sum_{l \in L_j} \sum_{u \in T} \overline{\nu}^m_{tl} \delta^S_{tu} y^E_{mtl}, \quad t \in T, m \in M^N, \\ & j = \text{'electricity'}, q = \text{'electricity producers'} \end{aligned} \tag{40}$$

Since input usage is in a fixed proportion to production, these conditional input demand functions are not directly dependent on the input price, only through the optimal production level.

3.5 International energy trade

Electricity and gas can be traded via international transmission lines or pipelines. The traded gas quantity z_{mn}^{G} is measured at the node of import *n* and since there is som e loss in transmission, a larger quantity $z_{mn}^{G}/\theta_{mn}^{G}$ must be exported from country *m*. Each line is owned by one agent who, taking all prices as given, maximizes the difference between the selling value in the import country minus the loss-adjusted purchasing value in the exporting country and the direct cost of transmission:

$$\Pi_{mn}^{Z} = \left[P_{nj}^{Y} - \frac{P_{mj}^{Y}}{\theta_{mn}^{G}} - c_{mn}^{G}\right] z_{mn}^{G} + \left[P_{mj}^{Y} - \frac{P_{nj}^{Y}}{\theta_{nm}^{G}} - c_{nm}^{G}\right] z_{nm}^{G}, j = \text{gas}; (m,n) \in MM^{G} \quad (41)$$

with an equivalent formulation for the period-specific trade in electricity,

$$\Pi_{mn}^{ZE} = \sum_{t \in T} \left\{ \left[P_{nt}^{YE} - \frac{P_{mt}^{YE}}{\theta_{mn}^{E}} - c_{mn}^{E}\right] z_{mnt}^{E} + \left[P_{mt}^{YE} - \frac{P_{nt}^{YE}}{\theta_{nm}^{E}} - c_{nm}^{E}\right] z_{nmt}^{E} \right\}, (m,n) \in MM^{E} \quad (42)$$

Note that Π_{mn}^{Z} and Π_{mn}^{ZE} means profits from importing from country m to country n, and from importing from country n til country m. The line owner maximizes profits given the constraint that the absolute value of net trade should not exceed the capacity of the link, that is

$$z_{mn}^{G} - z_{nm}^{G} \leq K_{mn}^{G\ 0} \perp \mu_{mn}^{G} \geq 0,\ \forall (m,n) \in MM^{G} \vee (n,m) \in MM^{G} \quad (43)$$

$$z_{mnt}^{E} - z_{nmt}^{E} \leq \psi_{t} K_{mn}^{E\ 0} \perp \mu_{mnt}^{E} \geq 0, t \in T; \forall (m,n) \in MM^{E} \vee (n,m) \in MM^{E} \quad (44)$$

Note that (43), as well as (44), implies two inequalities; one for import from country m to country n, and one from import from country n til country m.

In addition to recovering the capacity constraints, the FOCs of the transmission line owners is given by:

$$\begin{aligned}&P_{nj}^{Y}-\frac{P_{mj}^{Y}}{\theta_{mn}^{G}}-c_{mn}^{G}-\mu_{mn}^{G}+\mu_{nm}^{G}\leq 0\perp z_{mn}^{G}\geq 0,\\&j=\text{gas};\forall(m,n)\in MM^{G}\vee(n,m)\in MM^{G}\end{aligned} \tag{45}$$

$$\begin{aligned}&P_{nt}^{YE}-\frac{P_{mt}^{YE}}{\theta_{mn}^{E}}-c_{mn}^{E}-\mu_{mnt}^{E}+\mu_{nmt}^{E}\leq 0\perp z_{mnt}^{E}\geq 0,\\&t\in T;\forall(m,n)\in MM^{E}\vee(n,m)\in MM^{E}\end{aligned} \tag{46}$$

3.6 World Market for Oil and Coal

Demand for oil and coal in the non-model countries are modelled simply as linear demand functions:

$$x\_oth_{mj}=a_{mj}^{X}+b_{mj}^{X}P_{j}^{W},m\in M^{X}\cup M^{W},j\in J^{W} \tag{47}$$

Supply of oil and coal in the non-model countries are modeled in the same way as for the model countires, confer (8), that is, the producer price of the fuel should equal marginal costs:

$$P_{mj}^{Y}=ac_{mj}+bc_{mj}y_{j}^{m},\ m\in M^{X}\cup M^{W},j\in J^{W} \tag{48}$$

Equilibrium in these world markets is achieved by

$$x_{j}^{W}+\sum_{m\in M^{N}}z_{j}^{m}\leq y_{j}^{W}\perp P_{j}^{W}\geq 0,j\in J^{W} \tag{49}$$

where ROW demand plus the sum of net imports z_{j}^{m} to the endogenous countries is equal to ROW supply at positive prices. The complementarity condition ensures that excess supply is only feasible at a zero price. The actual net imports to each country are the quantities necessary to ensure price equality on domestic and international markets.

$$P_{mj}^{Y} = P_{j}^{W}, m \in M^{N}, j \in J^{W} \tag{50}$$

3.7 Domestic Market Equilibrium

Consumed quantities are in equilibrium equal to quantities delivered at a central node, minus a fixed proportion in distribution losses. Summing over consumers, suppliers and international trading partners gives us the following domestic market equilibrium conditions:

$$\sum_{q \in Q} \frac{x_{jq}^{m}}{\theta_{jq}^{m}} \leq y_{j}^{m} + z_{j}^{m} \perp P_{mj}^{Y} \geq 0,\ m \in M^{N}, j \in J^{W} \tag{51}$$

$$\sum_{q \in Q} \frac{x_{jq}^{m}}{\theta_{jq}^{m}} \leq y_{j}^{m} + \sum_{n \in M} \left\{ z_{nm}^{G} - \frac{z_{mn}^{G}}{\theta_{mn}^{G}} \right\} \perp P_{mj}^{Y} \geq 0,\ m \in M^{N} \cup M^{X}, j = \text{'gas'} \tag{52}$$

$$\begin{gathered} \sum_{q \in Q} \frac{x_{mtq}^{E}}{\theta_{jq}^{m}} \leq \sum_{l \in L} y_{mtl}^{E} + \sum_{n \in M} \left\{ z_{nmt}^{E} - \frac{z_{mnt}^{E}}{\theta_{mn}^{E}} \right\} \perp P_{mt}^{YE} \geq 0, \\ m \in M^{N}, t \in T, j = \text{'electricity'} \end{gathered} \tag{53}$$

where θ_{jq}^{m} denotes the loss adjustment in domestic energy distribution (1 - loss share). Note again that the gas equilibrium condition (52) is also applied for the exogenous countries, but not for ROW.

User prices, in addition to reflecting the producer price adjusted for losses ($P_{mjq}^{Y} / \theta_{jq}^{m}$), include non-loss distribution costs d_{jq}^{m}, energy excise taxes ε_{jq}^{m}, carbon taxes κ_{jq}^{m} adjusted for the carbon content of each fuel ω_{j}^{m} and value added tax τ_{jq}^{m}:

$$P_{mjq}^{X} = \left[\frac{1}{\theta_{jq}^{m}} P_{mj}^{Y} + d_{jq}^{m} + \varepsilon_{jq}^{m} + \omega_{j}^{m} \kappa_{jq}^{m} + \varsigma_{jq}^{m} \chi_{jq}^{m} \right] (1 + \tau_{jq}^{m}),\ \forall m \in M^{N}, j \in J, q \in Q \tag{54}$$

$$P^{XE}_{mtq} = \left[\frac{1}{\theta^{m}_{jq}} P^{YE}_{mt} + d^{m}_{jq} + \varepsilon^{m}_{jq} + \omega^{m}_{j}\kappa^{m}_{jq} + \varsigma^{m}_{jq}\chi^{m}_{jq}\right](1+\tau^{m}_{jq}), \quad (55)$$
$$\forall m \in M^{N}, t \in T, q \in Q, j = \text{'electricity'}$$

The price of reserve power P^{KPR}_{mt}, see (22) and (27), is set by the system operator(s) to ensure that there is always a reserve power capacity (percentage of maintained capacity) in each period and country, ρ_{mt}. The demand for reserve power is the result of a social optimisation problem not modelled here, and the price enters complementary to the reserve capacity constraint so that it will only be positive if the constraint is binding:

$$\rho_{mt}\sum_{l\in L}\psi_t K^{PM}_{ml} \geq \sum_{l\in L^{G}} K^{PR}_{mtl} \perp P^{KPR}_{mt} \geq 0,\ m \in M^{N}, t \in T \quad (56)$$

Since the production of electricity from geothermal, solar and wind (‘GSW’) is exogenous, this sector will not provide reserve power.

3.8 Carbon emissions

The emission of $C0_2$ in each country is the sum of the use of each energy form and the associated emission coefficient, plus a small amount of emission reflecting own use σ^{m}_{j} of fuel in extraction:

$$\mathrm{CO}^{\mathrm{m}}_{2} = \sum_{j\in J}\sum_{q\in Q}\omega^{m}_{j}x^{m}_{jq} + \sum_{j\in J}\omega^{m}_{j}\sigma^{m}_{j}y^{m}_{j},\ m \in M^{N} \quad (57)$$

In the basic model, (57) enters sequentially.

3.9 Emissions of SO2

The emissions of SO2 in each country is the sum of the use of each fossil fuel and the associated emission coefficient, plus net (exogenous) emissions from sectors that are included in RAINS but not in LIBEMOD:

$$\mathrm{SO}^{\mathrm{m}}_{2} = \sum_{j\in J}\sum_{q\in Q}\varsigma^{m}_{jq}x^{m}_{jq} + \sum_{q\in Q} os^{m}_{q} + proc^{m} - \varsigma^{m}_{ir}air^{m}, \quad (58)$$
$$m \in M^{N}, i = \text{'}oil\text{'}, r = \text{'}industry\text{'}$$

4. Long Run Model – Notation

Below we list up sets, parameters and endogenous variables that are contained in the long-run version of the model only. Note that some of the endogenous variables are exogenous variables in the short-run version.

Table 4: Additional sets – long run model

Symbol	Name	Content
L^{old} $(= L)$	Old electricity technologies	gaspower, coalpower, oilpower, nuclear, reservoir, pumped, CRW, GSW
L^{new}	New technologies	new_gaspower, new_coalpower, new_oilpower, new_nuclear, new_reservoir, new_pumped
Å	Future years	{1996,1997,…..,2020}

Table 5: Additional parameters – long run model

Symbol	Name	Unit	Gams name	Indices
Δ^E	Annual rate of depreciation in transmission of electricity	-	`DeltaKE`	
Δ^G	Annual rate of depreciation in transmission of natural gas	-	`DeltaKG`	
Δ_{ml}	Annual rate of depreciation in power capacity	-	`Delta (m,l)`	$m \in M, l \in L$
$o_{må}$	GNP index	-	`Omicron(m,å)`	$m \in M, å \in Å$
$å_0$	Model base year	-	`aa0`	
$å$	Last year	-	`Aa`	
ρ^I_{msl}	Fixed coefficient between inflow capacity and power capacity	-	`rhoI(m,s,l)`	$m \in M, s \in S$ $l = 'new\_reservoir'$
ρ^R_{ml}	Fixed coefficient between reservoir capacity and power capacity	-	`rhoR(m,l)`	$m \in M,$ $l = 'new\_reservoir'$
c^{inv}_{ml}	Annualised unit capital costs	MUSD/ GW	`CkP(m,l)`	$m \in M, l \in L$
c^{kP}_{ml}	Annualised capital cost coefficient	MUSD/ GW	`CkP(m,l)`	$m \in M,$ $l = 'new\_reservoir'$
c^{kP1}_{ml}	Coefficient in exponential function	-	`CkP1(m,l)`	$m \in M,$ $l = 'new\_reservoir'$
cke_{mn}	Annualised unit capital costs for transmission of electricity	USD/toe per 100 km	`CkE(m,n)`	$(m,n) \in MM^E$
ckg_{mn}	Annualised unit capital costs for transmission of natural gas	USD/ MW* kilometer	`CkG(m,n)`	$(m,n) \in MM^G$

Table 6: Additional endogenous variables – long run model

Symbol	Name	Unit	Gams name	Indices
K_{ml}^{P}	Power capacity in old technologies	GW	`KP(m,l)`	$m \in M, l \in L^{old}$
K_{ml}^{inv}	Investment in new technologies. Power capacity in new technologies	GW	`Kinv(m,l)`	$m \in M, l \in L^{new}$
K_{msl}^{I}	Inflow (energy availability) capacity in last year	TWh	`KI(m,s,l)`	$m \in M, s \in S,$ $l \in L^{old} \cup L^{new}$
K_{ml}^{R}	Reservoir (energy transfer between seasons) capacity in last year	TWh	`KR(m,l)`	$m \in M, l \in L^{old} \cup L^{new}$
K_{mn}^{E}	International electricity transmission capacity in last year	GW	`KE(m,n)`	$(m,n) \in MM^{E}$
K_{mn}^{G}	International gas transmission capacity in last year	MTOE	`KG(m,n)`	$(m,n) \in MM^{G}$
$Kinv_{mn}^{E}$	Investment in electric transmission lines	MUSD	`KEinv(m,n)`	$(m,n) \in MM^{E}$
$Kinv_{mn}^{G}$	Investment in natural gas transmission lines	MUSD	`KGinv(m,n)`	$(m,n) \in MM^{G}$
$V_{mqå}^{D}$	Demand income level in a future year å	-	`Vd(m,q,å)`	$m \in M$, $q \in Q$, $å \in Å$

5. Long Run Model – Relations

The long-run model contains several of the short-run relations. For these relations, costs and demand parameters reflect long-run considerations. In addition, the long-run version contains relations that determine power capacities and transmission capacities for natural gas and electricity. Finally, in the long-run version the model runner can choose between exogenous extraction of natural gas - as in the short-run version, cf. (5) and (6) - or endogenous extraction in the model countries. In the latter case, extraction is determined from price equal to marginal costs, cf. equation (8):

$$P^Y_{mj} = ac_{mj} + bc_{mj} y^m_j + dc_{mj} * \ln(1 - \tfrac{y^m_j}{K^{F\,0}_{mj}}) + c^L_m,\ m \in M^N, j \in J^G. \tag{59}$$

5.1 Electricity Supply from old technologies

All old technologies, $L = L^{old}$, depreciate over time:

$$K^P_{ml} = \left(1 - \Delta_{ml}\right)^{\mathring{a} - \mathring{a}_0} K^{P\,0}_{ml} \quad m \in M^N, l \in L^{old} \tag{60}$$

where Δ_{ml} is the annual rate of depreciation, $\mathring{a}_0$ is the base year of the model, $\mathring{a}$ is the last year (year of calculation) and K^P_{ml} is the power capacity in the last year. For reservoir hydro there is also depreciation in inflow capacity and reservoir capacity:

$$\begin{aligned} K^I_{msl} &= \left(1 - \Delta_{ml}\right)^{\mathring{a} - \mathring{a}_0} K^{I\,0}_{msl},\ m \in M^N, s \in S, l = '\mathit{reservoir}' \\ K^R_{ml} &= \left(1 - \Delta_{ml}\right)^{\mathring{a} - \mathring{a}_0} K^{R\,0}_{ml},\ m \in M^N, l = '\mathit{reservoir}' \end{aligned} \tag{61}$$

5.2 Electricity Supply from new technologies

In the long run model, there is investments in several types of technologies (L^{new}); new coal power, new gas power, new oil power, new pumped hydro, new reservoir hydro and new nuclear (optional). For each of these technologies (except reservoir hydro), the efficiency is constant (that is, ν^1_{ml} is zero). The producer determines the stock of capital, which per definition equals investment:

$$K_{ml}^{P} = K_{ml}^{inv} \tag{62}$$

The Lagrangian of the producer is quite similar to the one in the short run, cf. (22):

$$\begin{gathered}
\mathrm{L}_{ml}^{E} = \sum_{t\in T}\left(P_{mt}^{YE} y_{mtl}^{E} + P_{mt}^{KPR} K_{mtl}^{PR}\right) - C_{mk}^{P} - c_{ml}^{inv} K_{ml}^{inv} - \lambda_{ml}^{E}\left\{K_{ml}^{PM} - K_{ml}^{inv}\right\} \\
-\sum_{t\in T}\mu_{mtl}^{M}\left\{y_{mtl}^{E} - \psi_t\left(K_{ml}^{PM} - K_{ml}^{PR}\right)\right\} - \eta_{ml}\left\{\sum_{t\in T} y_{mtl}^{E} - \xi_l^{m}\sum_{t\in T}\psi_t K_{ml}^{PM}\right\} \\
-\sum_{t\in T}\phi_{mtl}\left\{y_{mtl}^{E}/\psi_t - \sum_{u\in T}\delta_{tu}^{S}\, y_{mul}^{E}/\psi_u - K_{mtl}^{PS}\right\}, \\
m \in M^{N}, l \in L^{new} - \{'new_reservoir'\}
\end{gathered} \tag{63}$$

where c_{ml}^{inv} is the annualised costs of investment per unit capacity. The FOCs are identical to the ones in the short-run model, with the addition of the FOC for optimal investment:

$$c_{ml}^{inv} \geq \lambda_{ml}^{E} \perp K_{ml}^{inv} \geq 0,\;\; m \in M^{N}, l \in L^{new} - \{'new\_reservoir'\} \tag{64}$$

For reservoir hydro, there are three types of capacities; power capacity, inflow capacity and reservoir capacity. Due to lack of data, we assume that there is a fixed relationship between inflow capacity and power capacity, and also that there is a fixed relationship between reservoir capacity and power capacity. Because power capacity per definition equals investment, these two relations are given by:

$$K_{msl}^{I} = \rho_{msl}^{I} K_{ml}^{inv},\; m \in M^{N}, s \in S, l = 'new\ reservoir' \tag{65}$$

$$K_{ml}^{R} = \rho_{ml}^{R} K_{ml}^{inv},\; m \in M^{N}, l = 'new\ reservoir' \tag{66}$$

where ρ_{msl}^{I} and ρ_{ml}^{R} are coefficients.

The profit of the new reservoir hydro producer is

$$\Pi_{ml}^{E} = \sum_{t\in T} P_{mt}^{YE} y_{mtl}^{E} - C_{ml}^{P} - c_{ml}^{kP} e^{c_{ml}^{kp1} K_{ml}^{inv}} K_{ml}^{inv},\; m \in M^{N}, l = 'new\_reservoir' \tag{67}$$

where we have assumed that annualized capital costs are increasing in power capacity (exponential form) since a profit-maximizing reservoir producer will develop "cheap" water falls project before moving on to more "expensive" projects. In (67) c_{ml}^{kP} reflects costs of investment in power capacity for the first (marginal) unit and c_{ml}^{kp1} is a parameter in the exponential function.

The Lagrangian of the new reservoir hydro producer, taken into account the additional restrictions (19) and (20), is

$$
\begin{aligned}
\mathrm{L}_{ml}^{E} = & \sum_{t\in T}\left(P_{mt}^{YE}y_{mtl}^{E} + P_{mt}^{KPR}K_{mtl}^{PR}\right) - C_{mk}^{P} - c_{ml}^{kP}e^{c_{ml}^{kp1}K_{ml}^{inv}}K_{ml}^{inv} - \lambda_{ml}^{E}\left\{K_{ml}^{PM} - K_{ml}^{P}\right\} \\
& -\sum_{t\in T}\mu_{mtl}^{M}\left\{y_{mtl}^{E} - \psi_{t}\left(K_{ml}^{PM} - K_{ml}^{PR}\right)\right\} - \eta_{ml}\left\{\sum_{t\in T}y_{mtl}^{E} - \xi_{l}^{m}\sum_{t\in T}\psi_{t}K_{ml}^{PM}\right\} \\
& -\sum_{t\in T}\phi_{mtl}\left\{y_{mtl}^{E}/\psi_{t} - \sum_{u\in T}\delta_{tu}^{S}\, y_{mul}^{E}/\psi_{u} - K_{mtl}^{PS}\right\} \\
& -\sum_{s\in S}\alpha_{msl}\left\{\sum_{t\in T_s}y_{mtl}^{E} + R_{s}^{m} - R_{s-1}^{m} - K_{msl}^{I}\right\} \\
& -\sum_{s\in S}\beta_{ms}\left\{R_{s}^{m} - K_{m}^{R}\right\},\ m\in M^{N}, l='new\_reservoir'
\end{aligned}
\tag{68}
$$

The FOCs are identical to the ones in the short-term model, with the addition of the FOC for optimal investment, which, after insertion from (65) and (66) is

$$
\begin{gathered}
c_{ml}^{kP}e^{c_{ml}^{kp1}K_{ml}^{inv}} \geq \lambda_{ml}^{E} + \sum_{s\in S}\left\{\alpha_{msl}\rho_{msl}^{I} + \beta_{ms}\rho_{ml}^{R}\right\} \perp K_{ml}^{inv} \geq 0, \\
m\in M^{N}, l='new\_reservoir'
\end{gathered}
\tag{69}
$$

5.3 Transmission

As in the short-run model we assume that natural gas and electricity can be traded via international pipelines or transmission lines. Moreover, each line is owned by one profit-maximizing agent, who takes all prices as given. In contrast to the short-run model transmission capacities are now determined through investments chosen by the owner. In addition there is depreciation in all transmission lines; in the last year $\mathring{a}$ transmission capacities for natural gas K_{mn}^{G} and electricity K_{ml}^{E} are given by:

$$
\begin{aligned}
K^G_{mn} &= (1-\Delta^G)^{å-å_0} K^{G\,0}_{mn} + Kinv^G_{mn},\ (m,n)\in MM^G \\
K^G_{mn} &= (1-\Delta^G)^{å-å_0} K^{G\,0}_{mn} + Kinv^G_{nm},\ (n,m)\in MM^G
\end{aligned}
\tag{70}
$$

$$
\begin{aligned}
K^E_{mn} &= (1-\Delta^E)^{å-å_0} K^{E\,0}_{mn} + Kinv^E_{mn}, (m,n)\in MM^E \\
K^E_{mn} &= (1-\Delta^E)^{å-å_0} K^{E\,0}_{mn} + Kinv^E_{nm}, (n,m)\in MM^E
\end{aligned}
\tag{71}
$$

where K^G_{mn} (K^E_{mn}) is capacity for natural gas (electricity) transmission lines in the final year, Δ^G (Δ^E) is the annual rate of depreciation for natural gas (electricity) transmission lines, and $Kinv^G_{mn}$ ($Kinv^E_{mn}$) is investment in natural gas (electricity) transmission lines.

For natural gas, the owner of the transmission line (pipeline) maximizes (confer (41))

$$
\begin{gathered}
\Pi^Z_{mn} = \left[P^Y_{nj} - \frac{P^Y_{mj}}{\theta^G_{mn}} - c^G_{mn}\right] z^G_{mn} + \left[P^Y_{mj} - \frac{P^Y_{nj}}{\theta^G_{nm}} - c^G_{nm}\right] z^G_{nm} - ckg_{mn} Kinv^G_{mn}, \\
j = \text{gas}; (m,n) \in MM^G
\end{gathered}
\tag{72}
$$

given the constraint (confer (43))

$$
z^G_{mn} - z^G_{nm} \le K^G_{mn} \perp \mu^G_{mn} \ge 0,\ (m,n)\in MM^G \vee (n,m)\in MM^G \tag{73}
$$

where ckg_{mn} in (72) is annualised (unit) capital costs for expansion of natural gas transmission lines.

Similarly, the owner of the electricity transmission line maximizes (see (42))

$$
\begin{gathered}
\Pi^{ZE}_{mn} = \sum_{t\in T} \left\{ \left[P^{YE}_{nt} - \frac{P^{YE}_{mt}}{\theta^E_{mn}} - c^E_{mn}\right] z^E_{mnt} + \left[P^{YE}_{mt} - \frac{P^{YE}_{nt}}{\theta^E_{nm}} - c^E_{nm}\right] z^E_{nmt} \right\} - cke_{mn} Kinv^E_{mn}, \\
(m,n)\in MM^E
\end{gathered}
\tag{74}
$$

given the constraint (confer (44))

$$
z^E_{mnt} - z^E_{nmt} \le K^E_{mn} \perp \mu^E_{mnt} \ge 0,\ \ (m,n)\in MM^E \vee (n,m)\in MM^E, t\in T \tag{75}
$$

where cke_{mn} in (74) is annualised (unit) capital costs for expansion of power transmission lines.

The FOCs for trade in natural gas and electricity are also for the long-run model given by (45) and (46), respectively, whereas the FOCs for investment in transmissions are given by

$$ckg_{mn} \geq \mu_{mn}^{G} + \mu_{nm}^{G} \perp Kinv_{mn}^{G} \geq 0,\ \ (m,n) \in MM^{G} \tag{76}$$

$$cke_{mn} \geq \sum_{t \in T} \psi_t (\mu_{mnt}^{E} + \mu_{nmt}^{E}) \perp Kinv_{mn}^{E} \geq 0,\ \ (m,n) \in MM^{E}, t \in T \tag{77}$$

Because investments increase capacity in both directions, capital costs should be compared with two shadow prices (one for each direction).

5.4 Demand

For all end-users in all countries, the income level in a future year å is given by

$$V_{mqå}^{D} = V_{mq}^{D\,0} o_{må} \tag{78}$$

where $o_{må}$ is an index showing the increase in income between the base year and year å.

6. Documentation of data

Below we describe the data sources used to calibrate the model. In each subsection we first describe data used to calibrate the short-run version of the model, and then describe data that are used in the long-run version only. The base year of the model is 1996.

6.1 End-user demand

In addition to the 13 model countries (Austria, Belgium [including Luxembourg], Denmark, Finland, France, Germany, Great Britain, Italy, Netherlands, Norway, Spain, Sweden and Switzerland), there is demand in "Rest of the OECD", Russia, "C1" (Bulgaria, Estonia, Latvia, Romania and Slovakia), Algeria and "Rest of World", that is, all countries in the world are included.

Period Length

Fossil fuels are traded in annual markets, whereas electricity is traded in two season markets (summer and winter) and each season consists of two periods (day and night). By assumption, each season is 6 months long and each time of day is 12 hours, implying 4 equal period lengths.

Quantities

Demand in each country is divided into two end-user groups or sectors, denoted 'household' and 'industry'. Household demand covers services and agriculture in addition to households, whereas industry demand covers both industry sectors and transport sectors.

Base year demand for fossil fuels is taken from *Energy Balances of OECD countries, 1995-1996* (IEA 1998b), and is measured in mtoe. In the statistics, household demand corresponds to 'Other sectors' for coal, petroleum products and gas. Industry demand is then taken as 'TFC' (total fuel consumption) minus household demand, and plus use in 'gas works', 'coal transformation' and 'other transformation'. Demand for fossil fuels in electricity production is taken from 'Electricity plants' plus 'CHP plants'.

Base year demand for electricity is taken from *Energy Statistics of OECD countries, 1995-1996* (IEA 1998e), and is measured in TWh. In the statistics, household demand is taken from 'Other sectors', whereas industry demand is taken from 'Final consumption' minus household demand. For both end-user groups, the use of heat is added after converting heat to electricity equivalents, cf. the discussion below on supply of electricity.

In order to calibrate demand for electricity, annual consumption quantities are split into period quantities according to the base year shares of electricity consumption. These are mainly based on UCPTE (1998a), which gives monthly quantities of electricity consumed (TWh) and the consumption load (MW) at 03:00 and 11:00 of the third Wednesday of each month. For the Nordic countries equivalent numbers are found in NORDEL (1997a) and NORDEL (1997b). For each month we assume that the ratio between the consumption load at 03:00 and 11:00 is equal to the ratio between consumption at day and consumption at night. Aggregating over summer months (April-September) and winter months (October-March) we find, for each country, how total annual consumption is divided between the four time periods. Due to lack of information, for each country the consumption shares are assumed equal across the consumption groups household and industry in the base year.

Prices and taxes

Base year prices and taxes are mainly taken from *Energy Prices and Taxes, 2nd Quarter 1998* (IEA 1998c), and so are exchange rates from national currencies to USD.

Prices after tax for fossil fuels are mainly taken from Table 2 in IEA (1998c) (national currencies per toe). However, the price of coal for households is taken from Table 1 (per tonne), and converted to per toe. For oil in the industry sector, there are different prices for different uses. Because our industry sector includes transport, prices on transport fuels should also be taken into account. Thus, we weigh four prices (gasoline, diesel, light fuel oil and heavy fuel oil) using quantities in the base year as weights. Prices on light and heavy fuel oil are taken from Table 2, whereas prices on gasoline and diesel are found in Table1 (prices per litre), under 'Automotive Diesel for Commercial Use' and 'Premium Unleaded (95 RON) Gasoline'. These are converted to prices per toe. Quantities are taken from IEA (1998e), that is, 'Motor gasoline' in the 'Transport sector', 'Gas/Diesel' in the 'Transport sector', 'Gas/Diesel' in the 'Industry sector' and 'Heavy fuel oil' in the 'Industry sector'.

Prices after tax for electricity are taken from Table 1 (national currencies per kWh). VAT rates are calculated, for each energy type and user, as the ratio of VAT per unit of measurement over ex-tax price plus excise tax per unit of measurement.

In the base year there were CO_2 taxes in the four Nordic countries and in the Netherlands. In general these vary across fuels and end-users. CO_2 taxes (per ton CO_2) are taken from NOU (1996) and ECON (1997). Exemptions and tax reductions are taken into consideration, so that average tax rates are estimated. To compute CO_2 taxes per toe, we use conversion rates between ton CO_2 and ton fuel (Statistics Norway) and between ton fuel and toe (British Petroleum). The resulting values (measured as CO_2 per toe) are 3.67 (coal), 3.17 (oil) and 2.24 (natural gas). Excise taxes excluding CO_2 taxes are calculated residually based on prices after tax, VAT rates, CO_2 taxes and prices before tax. Prices before tax are taken from the same sources as prices after tax.

The price and tax statistics have several missing values for 1996. For the Nordic countries the problem is treated by using other data sources. In other cases, we have been forced to make various assumptions to achieve a complete set of prices and taxes. Here we explain the imposed rules of thumb.

The statistics start in general in 1987, and prices and taxes are therefore given for earlier years than 1996 (the base year). For missing 1996 values we assume that changes in pre-tax prices follow the import costs of the fossil fuel (in absolute terms). Import costs of fossil fuels are given for several countries and for the EU in IEA (1998c). Moreover, we assume that excise taxes and VAT rates are constant over time, unless we know otherwise.

When no historical prices are available, we have sometimes used the same prices for the industry as for the electricity sector, or vice versa. Sometimes we have used the price in a neighbouring country, adjusted for differences in import costs. When VAT rates or excise taxes are missing we have assumed that these are equal across fuels for each end-user group in a country. When absolute no information is available, excise taxes are set equal to zero.

Direct price elasticities

Our aim is to find short-term and long-term direct price elasticities for coal, oil, natural gas and electricity for the two end-user groups household and industry. We use three sources: The SEEM model (Brubakk et al. 1995), the E3ME model (Barker 1998) and Franzen and Sterner (1995). In addition, quantities from the IEA statistics are used to weigh the original elasticities (i.e., IEA (1998b) and IEA (1998e)).

Brubakk et al. (1995) reports simulated elasticities for the industry (excl. transport), services and household sectors in Western European countries. The industry elasticities are calibrated based on Pindyck (1979), whereas the other elasticities are both estimated and calibrated. The elasticities for services and households in SEEM are weighted to derive elasticities for our household sector. Second, the industry elasticities for oil in SEEM are weighted with elasticities for gasoline in Franzen and Sterner (1995) to derive oil elasticities for our industry sector (industry elasticities for the other energy carriers are solely based on SEEM). The elasticities in Franzen and Sterner are time-series estimates based on data from OECD countries.

The E3ME model includes energy demand equations for 17 sectors in each Western European country. These demand equations are also aggregated to the national level. The sector-specific demand equations are based on time-series of both total energy demand in the sector (see Barker et al.; 1995) and fuel-specific demand in the sector (i.e., coal, heavy fuel oil, gas and electricity). As the direct price elasticities are not explicit parameters in the equations, these have to be derived from the other parameters. The direct price elasticity for fuel i (El^i_p) is computed from the formula[4] $El^i_p = El^i_{pr} * (1-k^i) + El^E_{pE} * El^i_{xE} * k^i$, where El^i_{pr} is the elasticity of demand for fuel i with respect to the price ratio between the price of fuel i and the aggregate energy price, El^E_{pE} is the elasticity of demand for total energy use with respect to the aggregate energy price, El^i_{xE} is the elasticity of demand for fuel i with respect to the aggregate energy use, and k^i is the share of fuel i in the energy aggregate.

[4] This formula is a slight approximation of the correct, but more complicated, relationship.

Some notes should be made about the original elasticities in the three studies we have used as sources. In some cases, elasticities are reported to be positive. However, these elasticities are set equal to zero. In the same manner, short-term elasticities below -1 are set equal to -1, whereas long-term elasticities below -2 are set equal to -2.

In order to compare the derived elasticities in E3ME with the elasticities based on SEEM and Franzen and Sterner (henceforth termed SFS), the SFS elasticities for our two sectors are weighted to obtain national elasticities. As our two sectors do not include power generation, whereas E3ME does, there is a small inconsistency in this comparison. Next, we construct adjustment factors based on the difference between E3ME and SFS. Under alternative 1, the adjustment factors are half the *percentage* difference between E3ME and SFS, though the factors are restricted to be in the range of -33 per cent to 50 per cent. These factors are then applied to the SFS elasticities for our two sectors (household and industry). Under alternative 2, the adjustment factors are half the *absolute* deviation between E3ME and SFS, though the factors are restricted to be in the range of -0.1 to 0.1 for short-term elasticities and -0.4 to 0.4 for long-term elasticities. These factors are then added to the SFS elasticities for our two sectors.

The derived short-run elasticities lie in the interval (-0.05 ; -0.43) under alternative 1, and in the interval (-0.04 ; -0.42) under alternative 2. The corresponding long-term elasticities lie in the interval (-0.14 ; -1.53) under alternative 1, and in the interval (-0.18 ; -1.65) under alternative 2. In the calibration of the model we have used alternative 1. However, there are not large differences between the derived elasticities under the two alternatives. Under alternative 1, the weighted household (industry) short-run elasticities for coal, oil, natural gas and electricity are –0.19 (-0.19), -0.21 (-0.20), -0.22 (-0.27) and –0.32 (-0.20), respectively. The weighted short-run elasticity (aggregated over fuels, sectors and countries) is –0.22 (alternative 1). The weighted household (industry) long-run elasticities for coal, oil, natural gas and electricity are –0.72 (-0.86), -0.89 (-0.83), -0.68 (-1.12) and –0.64 (-0.99), respectively (alternative 1). The weighted long-run elasticity (aggregated over fuels, sectors and countries) is –0.84 (alternative 1).

Cross price elasticities

Estimates of cross price elasticities vary significantly in the literature. Brubakk et al. (1995) find short-run elasticities mostly between 0.00 and 0.07 (average about 0.02), and long-run elasticities mostly between 0.01 and 0.5 (average about 0.1). As we do not find a certain pattern, we choose to use equal elasticities across fuels and countries. However, we assume that cross price elasticities in the industry are higher than in households, as firms are assumed to have a larger degree of flexibility in their choice of fuel. We choose 0.025 and 0.05 as the short-run cross price elasticities for household and industry, respectively, and 0.1 and 0.2 as the corresponding long-run cross price elasticities.[5]

Income elasticities

The sources used to find estimates for direct price elasticities are also used to find estimates for income elasticities for coal, oil, natural gas and electricity for household and industry. Moreover, the procedures for combining and comparing the data sources are also identical. The following formula was used to compute the income elasticities for fuel i (El^i_y) based on the E3ME study: $El^i_y = El^i_{xE} * El^E_y$, where El^i_{xE} is the elasticity of demand for fuel i with respect to the aggregate energy use, and El^E_y is the income elasticity for the energy aggregate.

All original income elasticities were non-negative (the elasticities for coal, oil and gas for German households were, however, zero). Yet, the procedure under alternative 2 produced two negative income elasticities due to the difference in aggregation levels. These were the elasticities of coal for household in Belgium and Germany, which are set equal to zero. Apart from these two estimates, all derived income elasticities lie in the interval (0.14; 1.88) under alternative 1, and in the interval (0.25; 1.80) under alternative 2. As for the direct price elasticities, we use alternative 1 in the (long-run version) of the model.

For the non-model countries, the income elasticities are indirectly based on IEA (2000), which presents projections to 2020 for e.g. fossil fuel prices and demand for fossil fuels for different regions. We use these projections, along with our demand functions, to calculate the "implicitly assumed" income

[5] Because the long-run direct price elasticities are four times larger than the short-run elasticities, we use this factor also for the cross-price elasticities.

elasticities. For oil, these are around 1, whereas for coal these are around 0.5. We therefore assume that for the non-model countries, the income elasticities for oil and coal are 1 and 0.5, respectively.

<u>GDP growth rates</u>

Historic GDP growth rates for each country and group of countries are based on IMF (2001). IMF presents annual growth rates for each year in the period 1997-2000. For the individual countries in the model, the growth rates are taken directly from the data source. For groups of countries, we have chosen the following approach. Growth rates for 'Rest of OECD' are calculated as weighted averages of growth rates in the US and Japan (GDP levels in 1996 are used as weights). For the group 'C1' we have used growth rates for 'Eastern European countries' in IMF (2001). For 'Rest of World' we have used growth rates for 'Developing countries'.

Future growth rates are partly based on forecasts from Consensus (2001), which includes annual growth rates for each year in the period 2001-2006 for selected countries, and average annual growth rates for the period 2007-2011 (but no information on growth rates after 2011). This information is available for 9 out of 13 model countries. Concerning the 4 remaining countries, Consensus presents forecasts for 2001 and 2002. For 2003-2011 we use an unweighted average of the 9 former countries for the 4 remaining countries. Regarding 'Rest of OECD' we use the same procedure as above, i.e., using a weighted average of US and Japanese growth rates. For model countries and 'Rest of OECD' we apply annual growth rates of 2.5 per cent in 2012-2020, which is approximately the average projected growth rates in the OECD in 2007-2011.

Outside the OECD, Consensus (2001) presents few forecasts. Thus, for Russia we simply assume growth rates of 2 percentage points above Rest-OECD. For the group 'C1' we use Consensus' growth rates for 'Eastern Europe' for the years 2001 and 2002. For 2003-2020 we use the same growth rates as for Russia. For 'Rest of World' we also assume growth rates of 2 percentage points above Rest-OECD. For Algeria we use the same growth rates as for 'Rest of World'.

Table 7: GDP annual growth rates for selected countries and groups of countries in the model. Historic rates and forecasts.

	Historic rates 1997-2000	Forecasts 2001-2005	2006-2011	2012-2020
Germany	2.1 %	1.8 %	2.1 %	2.5 %
United Kingdom	2.9 %	2.3 %	2.4 %	2.5 %
France	3.0 %	2.3 %	2.7 %	2.5 %
Italy	2.1 %	2.2 %	2.7 %	2.5 %
Other endogenous countries[1]	3.3 %	2.3 %	2.6 %	2.5 %
Rest of OECD	2.8 %	1.7 %	2.7 %	2.5 %
Russia	2.4 %	3.7 %	4.7 %	4.5 %
Rest of World	4.8 %	3.7 %	4.7 %	4.5 %

[1] Unweighted average of growth rates in other endogenous countries.

CES Demand parameters

For each of the annual energy goods gas, oil and coal, as well as the four period electricity goods, in the CES demand tree prices and quantities are taken from the sources above. As each annual good, including the electricity aggregate, enters in a nest complementary to an "energy-using good", the quantities and prices of these have to be specified. Lacking good sources, the prices of the complementary goods are all assumed to be one, and the quantities are all assumed to be equal to the value of the energy good in question. For the total value of consumption, including both energy and non-energy goods, the values are taken from national account statistics OECD (1997). We have no data for the value of production by sector in most countries, only for value added by sector. For Norway we have both value added and value of production by sector. We have estimated a value of production in each sector of the other countries by assuming that they have the same ratio of value of production to value added as the corresponding Norwegian sector.

The value for the "Industry" sector in the model is calculated as the sum of production value in the OECD mining, manufacturing, transport and construction sectors excluding the electricity production sector. The value for the houshold sector is the sum of the production value in agriculture and services plus the value of final consumption. In the top level nest a general "money" commodity enters complementary to the total energy aggregate. The price of this "money" good is set at one, and the quantity is calculated to make the sum of the values of the energy aggregate and the "money" good equal to the value of total consumption.

The share and substitution parameters in the CES tree are calibrated to minimise the deviation from the target own- and cross-price demand elasticities. In addition to the elasticities for annual energy goods mentioned above, the target cross-price elasticities between night and day electricity is set at 0.2, and between summer and winter is set at 0.0. For almost all countries this procedure implies that all own-price elasticities have the target value, but the cross-price elasticities are equal to the target value on average only, since the exact target values are inconsistent with economic theory. For some countries the resulting substitution parameters are so high that the demand system becomes unstable, and for these a maximum of 3 is set for the substitution parameter, resulting in own-price elasticities that deviate slightly from the target values.

In the short-term model the “endowment” parameter is set at zero. In the long-term model, the “endowment” parameter for each good is calculated so as to set the income elasticity at the target value specified above, at the same time recalibrating the share and substitution parameters with the same procedure as in the short run model.

6.2 Supply of fossil fuels

Base year supply of fossil fuels in the model countries is taken from IEA (1998b), and is measured in mtoe. We use 'Indigenous production' of coal, crude oil and gas minus 'Own use', to obtain net production of each fuel. All short-run elasticities for oil and coal are set to 0.25 and 1, respectively, whereas all long-run elasticities for oil and coal are set to 1 and 4, respectively, see Golombek and Bråten (1994).[6]

Long-run supply of natural gas from the model countries

The aim is to establish long-run unit cost functions for extraction of natural gas, that is, functions including both capital and operating costs. Moreover, short-run unit cost functions (i.e. only operating costs) are investigated in order to compare them with short-run equilibrium prices to check whether extraction from existing fields may be unprofitable even when capital costs are sunk.

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[6] In the short run model supply of natural gas from each of the model countries is exogenous (equal to the 1996 extraction levels), whereas in the long run model supply of natural gas from each of the model countries can either be exogenous (equal to the 1996 extraction levels) or endogenous (see below).

In general, we base our calculations on data for fields already under extraction. This may seem inappropriate as the long-run cost function should depend on costs of future extraction. However, as we do not have data for future field developments, we assume that unit costs from the nearest past are fairly good approximations for unit costs in the nearest future. While technological change may *reduce* average costs, depletion of the resource base may *increase* average costs as the cheapest fields are generally developed first. Hence, we cannot say a priori whether the calculated costs underestimate or overstate future costs of extraction.

i) UK

There are two sources used in the calculations of cost functions for the UK: Data from WoodMackenzie (WM) from the early 1990's and from World Gas Intelligence (WGI 1993). Both sources give information about total costs and total reserves for individual gas fields in the UK (or combined gas and oil fields). WM includes existing fields with start up before 1994-1995 (55 fields), whereas WGI includes fields with start up later in the 1990's (38 fields). WM gives much more detailed information about each field, particularly the distribution between capital costs and operating costs. We have assumed that total costs reported by WGI are equally distributed on capital costs and operating costs. This assumption seems valid based on the data from WM.

Total unit costs are calculated by determining the constant real price that gives a net stream of discounted income which exactly covers the total discounted costs of the field. Information on peak production is given by WM, and we assume a constant decline rate of extraction equal to the ratio between peak production and total reserves. The fields reported by WGI are assumed to have decline rates similar to the average rate reported in WM. Capital costs are assumed to be paid the year before extraction starts, whereas operating costs are distributed equally over the stated life time of the field. We assume that the lifetime of the WGI fields are the same as the average life time reported by WM. Several of the fields are combined natural gas and oil fields. When more than 50 per cent of total reserves are oil, it is assumed that the field is developed for oil extraction in any case, so that only operating costs are relevant for natural gas.

Annual production is calculated for each field for the year 2000 based on peak production, decline rates and information on peak year. By sorting the fields according to rising unit costs, and adding the field production levels consecutively to get accumulated production, we obtain a unit cost function that increases in accumulated production. This is done both for total unit costs and for operating unit costs. The total accumulated production level is calculated to be 72.5 mtoe per year, which is somewhat below actual UK production in the latest years. Moreover, UK production is expected to increase rapidly over the following years, reaching a peak of 108 mtoe per year in 2002 (WGI 1997), and then level out. Hence, we have drawn out the unit cost function in a uniform way so that the rate of capacity utilisation is almost 100 per cent when total production is 108 mtoe.

Finally, in order to establish an approximate unit cost function, we apply the general functional form:

$$c = a_0 + a_1*q + a_2*\ln(1-q/Q)$$

where c denotes unit costs, q accumulated production per year, Q annual capacity, and a_0, a_1 and a_2 are parameters. The three parameters and Q are determined so that the curve fits well with the curve based on field information (see above). In the case of the UK, we obtain the following function for total unit costs (1996-$): [7]

$$c = 20 + 0.6*q - 32*\ln(1-q/110)$$

ii) The Netherlands

The WoodMackenzie source is also used for the Netherlands. WM includes field information for 59 fields, which mainly consist of natural gas. Unit costs and annual production for the year 2000 are calculated for each field in the same manner as for the UK. One exception is annual production in the huge and very cheap field Groningen, where actual production is determined by the Dutch government in order to maintain a certain level of Dutch production over a long time period. Hence, we have fixed the annual extraction from Groningen at 35 mtoe per year, so that total Dutch production is in line with actual production in the latest years.

Unit cost functions for total costs and for operating costs are determined as for the UK. The following function fits well with the unit cost function for total costs (1996-$):

$$c = -15 + 1*q - 11*\ln(1-q/70)$$

[7] In the calibrations, emphasis is put on finding functions that fit well for relatively high rates of capacity utilisation, that is, where unit costs are of the same order of magnitude as current prices and producer prices in a liberalised market.

iii) Norway

The WoodMackenzie source is also used for most Norwegian fields. In addition we have used information from the Norwegian Oil Directorate (OD). Unit costs and annual production in 2000 are calculated for existing fields in the same manner as for the UK. For some of the newer fields we have used information about break even prices and peak production from the OD. These two sources amount to an annual production of 63 mtoe. In addition there are several other fields coming up in the next couple of years (and some fields are approaching shut-down), so that annual production is expected to stabilise around 70 mtoe from around 2005. Thus, we adjust accumulated production so that the rate of capacity utilisation is almost 100 per cent for 70 mtoe per year.

The following function fits well with the unit cost function for total costs (1996-$/toe):

$$c = 44 - 0.2*q - 23*\ln(1-q/70)$$

iv) Other model countries

All other model countries have linear marginal cost functions for extraction of natural gas with long-run elasticities equal to 1, see Golombek and Bråten (1994).

<u>*Supply from non-model countries*</u>

Base year supply (of oil and coal) from non-model countries is taken from *Energy Statistics and Balances of non-OECD countries, 1995-96* (IEA 1998d). All short-run elasticities for oil and coal are set to 0.25 and 1, respectively, whereas all long-run elasticities for oil and coal are set to 1 and 4, respectively, see Golombek and Bråten (1994). Net imports of natural gas to the model countries from the non-model countries are import numbers taken from *Gas Information, 1997* (IEA 1998f).

If extraction starts with cheap fields and then move on to expensive fields, costs of extraction will increase over time. However, due to technological progress and the possibility of discovering new cheap fields, costs of extraction may decrease over time. In order to assess which factors are the largest we have used IEA (2000), which presents projections to 2020 for e.g. fossil fuel prices and supply of fuels for different regions. We use these projections, along with our supply functions, to calculate the "implicitly assumed" annual shift in the supply functions. We find that both for oil and coal the rates are close to zero, that is, in the long-run model we assume that the supply functions do not shift over time.

6.3 Electricity Supply

Electricity Capacity

The power capacity of each electricity producing technology is, for each country, taken from *Electricity Information 1997* (IEA 1998a). This implies that the capacities of the multi-fueled power plants are distributed according to actual fuel use in 1996. The resulting distribution of capacity thus understates the fuel substitution possibilities.

Electricity Efficiency

The actual thermal efficiency for the fossil fuel based technologies is based on observed fuel use and production of heat and electricity. These are reported in IEA (1998a). The mix of heat and electricity production shows a wide dispertion between countries and fuels, and the data did not lend support to a common trade-off between heat and electricity across fuels. These trade-offs were therefore estimated separately for each fuel on 1996 data from the cross section of the 13 model countries. For gas, oil and coal the results were highly significant linear relationships (all variables measured in TWh):

Gas: $\text{Electricity} = -0.526*\text{Heat} + 0.468*\text{Gas}$ (R^2=0.999)

Coal: $\text{Electricity} = -0.379*\text{Heat} + 0.383*\text{Coal}$ (R^2=0.998)

Oil: $\text{Electricity} = -0.211*\text{Heat} + 0.415*\text{Oil}$ (R^2=0.999)

For each relationship the first coefficient is interpretable as the change in electricity produced per unit increase in heat production, and the second coefficient is interpretable as the gross thermal efficiency had all production been electricity. For waste power (CRW)[8] the results were not significant:

CRW: Electricity = -0.030*Heat + 0.164*CRW (R^2=0.097)

The non-significance may partly be due to deficiencies in the measurement of the energy content of the input fuel.

The estimated heat-electricity trade-off coefficients were used to convert heat produced in 1996 to its electricity equivalent. Since the CRW coefficients were not significant, the fuel data were pooled to estimate an average trade-off (-0.379) which was used for converting CRW heat to electricity equivalents. All base year electricity quantities (production and consumption) are thus corrected to include (transformed) heat.

So far we have obtained estimates for gross electricity production for different technologies. IEA (1998a) also contains information (for each country) on the ratio between net and gross electricity production for the group of combustible fuels. We used this ratio to calculate net electricity production for different combustible fuels. For the other types of technologies, IEA (1998a) contains information on net electricity production. The average thermal efficiencies were then, for each country and technology, calculated as the ratio of net "electricity" production to fuel use. The thermal efficiencies are then multiplied by the MTOE to TWh conversion factor 11.8.

Due to the fact that efficiency differs across plants with the same type of technology, we assume that thermal efficiency is a linear function of capacity utilisation.[9] To determine a linear function one needs two exogenous values. We let one point be the thermal efficiency of the most efficient plant, which is assumed equal to the efficiencies reported for new plants in 2000 in *Projected costs of generating electricity, update 1992* (IEA, 1992). If the country in question reports no efficiencies in IEA (1992), we have used figures from *Contribution of the Electricity Sector to the Reduction of CO_2-emissions in*

[8] The technology is termed CRW - Combined Renewables and Wastes – and it comprises solid biomass and animal products; industrial waste; municipal solid waste; and gases derived from biomass and wastes.

[9] For pumped storage we assume a fixed efficiency, which is calculated as the ratio of electricity produced to electricity consumed with data from IEA (1998a).

*Belgium (*Lissens, Proost, Van Regemorter and Van Rensbergen, 1995). Since the technical projected efficiencies do not take account of heat production, some observed 1996 average efficiencies are in fact higher than the estimate for best available technology in 2000. In these cases we define maximal efficiency as the observed 1996 average efficiency multiplied with a factor of 1.05.

A candidate for the second point of the linear function could be observed efficiency, calculated as net electricity production to fuel use. However, it is not straightforward to use the observed average efficiencies to determine the other fixed point of the linear efficiency function. Firstly, the unused parts of all electricity capacities have unobserved efficiency. Assuming these are mainly vintage plants with lower efficiency, the ("true") average efficiency of total capacity will be lower than the observed average efficiency. Secondly, the different electricity producing technologies do not have a constant rate of capacity utilisation throughout the year. These rates are not known from primary data. The data only provide information on annual rate of capacity utilisation for each technology and the distribution of total production over the four time periods. Instead of using average efficiency directly to determine the second point, we calibrate the capacity utilisation for each technology and period by imposing that, for each country, the outcome should be consistent with cost minimisation in electricity production, given our data. The problem is solved by running the electricity production block of the model. The solution of the problem provides the efficiency of the least efficient plant (for each technology and country), which is used as the second point in the linear efficiency function.

Operation and Maintenance Costs

Operation and Maintenance Costs (O&M costs) are taken from the same sources as those we use in order to estimate electricity efficiency. We assume that for each technology, 20 per cent of the O&M costs are due to non-variable operating costs, 30 per cent are due to short-run maintenance costs, and 40 per cent are due to start-up costs. The remaining 10 per cent are due to long-run maintenance costs and are therefore related to the investment decision (see below).

Availability Factors

All electricity plants require some downtime for maintenance and upgrading. The model reflects this by restricting total annual production to a fraction of installed capacity (for each country and technology). Since the model endogenously determines the economically optimal downtime, this restriction should reflect technical requirements only. Unfortunately, we have no clear data on technically required downtime, as all cost calculations available use some notion of expected downtime for both economic and technical reasons.

Nuclear plants are typically run as base-load in most countries, so we have assumed that the actual usage reflects technological requirements. Hence, for nuclear we have calibrated the availability coefficient as the ratio of actual use to capacity (in the base year). France, however, has a capacity utilisation in 1996 of 0.76, indicating that production is restricted also due to economic factors (nuclear capacity, which amounts to 55 per cent of total capacity, is high relative to base load demand). For this country we have therefore used the average rate of capacity utilisation for all other countries (0.84) as an estimate. For all *other* technologies the availability factor has been set at 0.90.

A related question is the need for backup power in the case of large unforeseen changes in demand or failure of supply, which otherwise might force a shutdown or even destroy parts of the electricity system. The size of this pure uncertainty would in a fully stochastic model be formulated as a willingness to pay for avoiding power outages, that is, we would derive an endogenous demand for power supply backup. In our non-stochastic model, a system operator buys in each period and country a fixed share of 5% of the capacity as reserve capacity.

<u>Supply of reservoir hydro</u>

i) Inflow capacity

For Norway, Sweden and Finland the inflow capacity, that is, the amount of precipitation in the catchment area in a hydrological normal year, is documented in Nordel (1997a). For the other model countries we used data from IEA (1998a). This statistics provides, for each country, the mean for the years 1993-1996 of net reservoir hydro generation per unit net reservoir hydro generation capacity. This figure is multiplied with the 1996 net generation capacity. The result is a country-specific estimate of inflow capacity in a hydrological normal 1996 year.

ii) Reservoir capacity

The reservoir capacity measures how much water (GWh) that can be stored in the reservoir, that is, the maximum amount of water that can be transferred from the end of the summer season to the beginning of the winter season, and vice versa. Below we distinguish between nominal reservoir capacity and feasible reservoir capacity. The difference is due to uncertainty margins (back-up supply).

Nordel (1997a) provides data on nominal reservoir capacities for Norway, Sweden and Finland. The statistics provides data also on hydro generation in a hydrological normal year for Norway, Sweden and Finland. These data are used to construct (for each country) reservoir capacity (GWh) per unit hydro power generation (TWh). The mean of these numbers is taken as an estimate for the remaining model countries. Because UNIPEDE (1997) provides data on power generation from hydro, we can derive estimates of nominal reservoir capacity for the remaining countries.

From Nordpool (1999) we have numbers for maximum, minimum and median filling share for Norway, Sweden and Finland for 1 April and 1 October. For each of these countries, we use the difference between maximum filling share at 1 October and minimum filling share at 1 April as an approximation for the share of the reservoir that can be transferred from the end of the summer season to the beginning of the winter season. The product of a share and the corresponding nominal reservoir capacity is termed feasible reservoir capacity. Finally, for the remaining countries we use the weighted shares of the Nordic countries to estimate feasible reservoir capacities.

<u>New technologies</u>

For gas power, coal power, oil power and nuclear we assume that all agents are in a position to invest in the most efficient technology (long run model). Furthermore, relying on the theorem of factor price equalization (long run), capital costs and O&M costs do not differ between the model countries.[10] Efficiencies and costs are taken from *Projected costs of generating electricity*, *update 1998* (IEA 1998h).[11] For new pumped storage there is constant efficiency within each country but these

[10] In the model, the parameter "capital costs" include 10 per cent of the O&M costs, see the section Operation and Maintenance Costs above.

[11] Because there is no information on oil power neither in IEA (1992) nor in IEA (1998h), costs of capital and O&M are taken from IEA (1987). Moreover, for new oil power the efficiency is set equal to the best efficiency among the operating oil power plants in the short run model.

efficiencies differ across countries due to e.g. topological differences. For each model country the efficiency for new pumped storage is set equal to the efficiency of pumped storage in the short run model.

Finally, for reservoir hydro electricity capacity we use UNIPEDE (1997) for investment costs in run-of-river, pondage, and reservoir plants. Due to the limited availability of precipitation and reservoir potential, there will be increasing long run marginal costs as the least costly lakes and rivers are exploited first. We only have information on long run marginal costs for different projects in Norway, see NVE (1997). These micro costs are organised in a step function, which is then smoothed by an exponential function. For the other countries we use the same exponential function, proportionate to the initial capacity in each country, and with a starting point (cost of the cheapest project) modified by the mix of run-of-river, pondage, and reservoir plants in each country. The capacity cost functions are functions of inflow capacity, but the power capacity and size of reseservoir capacity are assumed to grow proportionately.

6.4 Transportation of electricity

Electricity transmission capacity

We have used UCPTE (1998a) and NORDEL (1998) as sources for international transmission capacities. UCPTE (1998a) has data on nominal transmission capacities between the UCPTE countries (most Western European countries except Norway, Sweden, Finland and the United Kingdom) and between UCPTE countries and countries having boundary with UCPTE countries. NORDEL (1998) contains nominal transmission capacities between the Nordic countries.

It is difficult to estimate feasible transmission capacities in an electricity network. This is partly because all networks have weak parts that restrain feasible capacity, and partly due to loop flow.[12] However, we can utilise that both of our sources report transmission capacity for the line between Denmark and Germany. The estimate of feasible transmission capacity in NORDEL (1998) is slightly below 50 per cent of nominal capacity reported in UCPTE (1998a). We use the estimate from

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[12] Loop flows occur when the laws of physics imply that the physical power path is different from the contractual path, and this may reduce transmission capacity, see Hogan (1993).

NORDEL (1998), and we also assume that for all other transmission lines feasible capacity is 50 per cent of nominal capacity. However, for sea cables we use nominal capacity as an estimate for feasible capacity.

Costs of electricity transmission

We follow Amundsen et al. (1997), which for most transmission lines have a loss factor of 2 per cent. Moreover, we assume that O&M costs are 1.5 per cent of the (total present value) investment costs for transmission lines, see Statnett (1998) and NVE (2000), and 5 per cent of (annualised unit) capital costs for sea cables, see Vognhild (1992).[13]

Costs of domestic transport and distribution of electricity

The IEA (1998e) contains, for each country, figures for domestic electricity transport and distribution losses in 1996. In the model, transport losses associated with industrial use is set at 2 per cent, see Amundsen et al. The household sector is assumed to have the residual losses, that is, its loss share is the residual loss quantity divided by total household consumption including loss.

Estimates for costs for national transport and distribution are also found in Amundsen et al. Their 14 NOK/MWh (2.2 USD/MWh) for industry and 88 NOK/MWh (13.5 USD/MWh) for households were applied in all countries in their model. A study of Norwegian distribution utilities finds 157 NOK/MWh in 1989, but this figure includes the cost of supply (though not the electricity itself), see Kittelsen (1994). Moreover, the Norwegian distribution system is thought to be costly because of adverse topography and climate. Our costs of national transport and distribution are therefore based on the Amundsen et al. numbers, but inflated to 1996 prices and converted into USD. The resulting 2.5 USD/MWh for industry transmission costs is used in all countries, but the household distribution cost of 11.8 USD/MWh is varied across countries in proportion to the estimated distribution losses.

[13] Amundsen et al. (1997) has a tariff of 10 NOK per MWh (that is, about 1.5 USD/MWh). This tariff can be compared with our estimate of the investment cost: If a transmission line of 300 kilometre has 25 years of life time and a utilisation factor of 50 per cent, then if the tariff is 10 NOK per MWh the net present value of the project is around zero if the (real) discount rate is 7 per cent. The tariff of 10 NOK per MWh is roughly twice as high as the average O&M costs in our model.

Capital costs for transmission lines

We now turn to the costs of constructing (high voltage) transmission lines and sea cables (used in the long-run version of the model). For transmission lines a number of sources have been investigated. In Uthus et al. (1998) Norwegian regional transmission companies were asked to estimate the costs of transmission lines and sea cables. We have used the mean of the reported costs of constructing 300 kV and 400 kV transmission lines (measured per kilometre) as one estimate. From Eltra (1999) we get another estimate, which is based on one specific project (the 31 kilometre line between Vejen and Endrup). In Statnett (1996) the costs for a transmission line in the Kristiansand area in Norway is reported. Vognild (1992) reports the cost of a (300 kilometre) transmission line between Norway and Sweden. Finally, in NOU (1998) The Norwegian Oil and Energy Department presents cost estimates. The above estimates are in the range of 141 to 555 USD per MWkilometre. Based on the information from our sources the estimate is set to (1996) USD 200 per Mwkilometre.

For sea cables we have two sources. Vognild (1992) reports 950 USD dollars per MWkilometre, whereas the estimate from Statnett (1998) is almost twice as high. We have chosen 1300 (1996) USD dollars per MWkilometre as the estimate of costs of constructing sea cables. For both lines and cables we assume that connecting costs to the national grid are covered by the domestic transmission tariffs.

6.5 Electricity trade

Electricity Information (IEA, 1998a) is used as the main source for electricity trade. For trade between model countries we use export numbers, whereas we use import numbers for trade with non-model countries. For trade between the region of the model countries and the non-model countries, the yearly figures have been divided into day/night and winter/summer shares in the following way:

i) Trade between Continental Europe and non-model countries

From UCPTE (1998a) we have monthly values for electricity trade in 1996 with non-model countries. UCPTE (1998b) and UCPTE (1999) provide information on load flows (MW) between Continental European countries and other countries for the third Wednesday of December in 1997 (and the year after). Combining these sources makes it possible to derive day and night shares for the winter electricity trade. Due to lack of information we assume that summer trade is distributed equally between day and night.

ii) Trade between Finland and Russia

From Nordpool (1999) we have hourly data for 1998 and 1999, which is used to find the shares between day and night electricity trade. The distribution between summer and winter is found in Nordel (1997b).

iii) Imports to and exports from Norway[14]

From Nordel (1994-1999) we have monthly values for Norwegian electricity trade for the period 1996-1999. Nordpool (1999) contains information on Norwegian hourly electricity trade for the period 1996-1999. Information in Statistics Norway (1998) makes it possible to approximate gross Norwegian electricity trade in a hydrological normal year. Combining these sources we derive the distribution of Norwegian electricity trade in 1996 between summer/ winter and day/night.

Gas trade

All trade figures are taken from Gas Information (IEA, 1998f) (import numbers are only used for trade with non-model countries).

6.6 Transportation of natural gas

Natural gas transmission capacities

All figures are taken from a model developed by the Foundation for Research in Economics and Business Administration (SNF), see Grabarczyk, McCallum and Wergeland (1993). We have used data from the latest version of the model (no written documentation is available), which were then updated by industry experts.

Costs of natural gas transport

The main source is Golombek, Gjelsvik and Rosendahl (1995). However, due to substantial cost reductions in construction of new transmission lines over the last decade, and the fact that most of the present transmission lines have already received revenues that cover initial investment costs, our cost

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[14] Norway can either be a model country or a non-model country.

figures are lower than in Golombek et al. (1995). Hence, when pipeline capacities are not fully utilised the short-run onshore tariff in Western Europe – measured in 1996 USD per toe per 100 km – is set to 1.25 (0.5 in non-model countries). The corresponding offshore tariff is 2.50. Finally, for international transmission the loss factor is 2 per cent (conversation with industry experts). In the long-run model O&M costs are 2 per cent of the short-run tariffs, whereas capital costs are 98 per cent of the short-run tariffs.

Costs of domestic transport and distribution of natural gas

For both domestic transport and distribution the starting point is an official cost estimate for Germany. According to *Natural Gas Distribution* (IEA, 1998g), costs of transport in Germany is 55 USD per toe, whereas costs of distribution is 105 USD per toe. These figures are used to estimate the costs of the other model countries under the assumption that for each type of cost, the difference between two countries is due to amount of natural gas transported/distributed (data from IEA (1998b)) and the length of the domestic transport/distribution network (data from Figas (1997)).

6.6 Emissions

Emission coefficients for CO2 (ton CO2 per toe) differ across fuels (natural gas, different types of coal and oil). We have chosen to use the same set of emission coefficients for all countries. These are 2.24, 3.17 and 3.67 for natural gas, oil and coal, respectively.

For emissions of SO2 we use the RAINS data base to estimate emission coefficients (1000 ton SO2 pr mtoe) for different fuels, sectors and countries, see Alcamo and Hordijk (1991) on the RAINS model. Because the RAINS model is more disaggregated than LIBEMOD with respect to fuels and sectors, we have developed a key that aggregates from RAINS to LIBEMOD. For the model countries the average emission coefficients are shown in Table 8.

Table 8: Average emission coefficients for SO2 (1000 ton SO2 per mtoe) for all model countries.

	Household	Industry	Power production
Natural gas	0	1.8	0
Electricity	0	0	0
Coal	301.9	79.7	253.0
Oil	68.6	29.1	324.9

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