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LIBEMOD 2000 – LIBEralisation MODel for the European Energy Markets: A Technical Description

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Abstract: This paper gives a detailed mathematical description of LIBEMOD 2000 and LIBEMOD MP, which are economic computable equilibrium models for the Western European natural gas and electricity markets. LIBEMOD 2000 assumes that all markets are competitive both in the short run and in the long run, while LIBEMOD MP allows for market power. 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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Preface

This working paper documents the models LIBEMOD (LIBeralization MODel) and LIBEMOD MP (LIBeralization MODel with initial Market Power). Both models have been developed through grants from the Norwegian Research Council. LIBEMOD received support under the programs SAMRAM and SAMSTEMT. Finn Roar Aune, Rolf Golombek, Knut Einar Rosendahl and Sverre Kittelsen developed the LIBEMOD model. The development of LIBEMOD MP received support under the program PETROPOL. Kjell Arne Brekke, Rolf Golombek and Sverre Kittelsen developed the LIBEMOD MP model.

In the course of developing the models, it became expedient to integrate them. Thus, the calibration of the models is identical. While some of the calibrated parameters (mark-up factors) are used directly in LIBEMOD MP, these parameters are set equal to zero in LIBEMOD in order to obtain a model will competitive markets. This is the only difference between the two models.

Content

1. Introduction

LIBEMOD (LIBEralization MODel for the European Energy Markets) is an economic computable equilibrium model for Western European natural gas and electricity markets. The model also includes world markets for oil and international tradable types of coal, as well as domestic markets for lignite and biomass. In one version of the model, all markets are competitive, including markets for transportation of energy goods and markets for reserve power capacity, whereas in another version of the model, there is imperfect competition in all markets, except the markets for reserve power capacity. There are seven goods in the model (steam coal, coking coal, lignite, natural gas, oil, electricity and biomass) that are produced, traded and consumed in each of the 17 model countries (Austria, Belgium (including Luxembourg), Denmark, Finland, France, Germany, Greece, Ireland, Italy, Japan, Netherlands, Norway, Portugal, Spain, Sweden, Switzerland and the United Kingdom (UK)). In addition, there is production, trade and consumption of steam coal, coking coal and oil in all exogenous countries. While fossil fuels are traded in annual markets, electricity is traded in period markets (summer versus winter, six periods during a 24-hour cycle) because power cannot be stored (except in limited-capacity hydro-reservoirs). In each model country, there are a number of technologies available for supplying electricity. These are (steam) coal power, lignite power, gas power, oil power, biomass power, nuclear, pumped storage hydro, reservoir hydro, waste power and wind power.

We distinguish between the *short-run* version of the model and the *long-run* version. In the short-run version, the capacities in the international transmission of natural gas and electricity, as well as power production, are given. These capacities are determined in the long-run version of the model. The long-run model can be run either for the data year or for a future year. If the latter option is chosen, installed capital has to be depreciated, whereas the income level has to be increased.

While this working paper is a technical description of LIBEMOD, a fuller economic explanation is provided in Aune et al. (2008), where the model is applied to the effects of liberalising the energy markets of Western Europe. Note that in that book Japan is treated as an exogenous country.

Chapters 1 to 4 of this working paper documents LIBEMOD 2000, which is an updated version of LIBEMOD 96, see working paper no 1/2001 from the Frisch Centre (Aune et al., 2001). The main changes from the 1996 to the 2000 version are the following: First, data have been updated from 1996 to 2000. Second, the modelling of coal is much richer. Third, there are more time periods for trade in electricity, and finally, the modelling of the market for power capacity has been improved (domestic system operators make sure that there is sufficient reserve power capacity available). Chapter 5 documents LIBEMOD MP, which is the LIBEMOD model with Market Power.

2. Notation

For each symbol, indexes are in small letters and can appear as both subscripts and superscripts. Superscripts in capital letters denote a separate variable, not an index.

Table 1 Sets

Symbol	Name	Content
M	Countries	$M^N \cup M^G \cup M^C \cup M^W$
M^N	Model countries	at (Austria) be (Belgium and Luxembourg) ch (Switzerland) de (Germany) dk (Denmark) es (Spain) fi (Finland) fr (France) gr (Greece) ie (Ireland) it (Italy) jp (Japan) nl (The Netherlands) no (Norway) pt (Portugal) se (Sweden) uk (United Kingdom)
M^G	Gas-exporting countries	dz (Algeria) ru (Russia) ua (Ukraine)
M^C	Coal-exporting countries	au (Australia) ca (Canada) cn (China) cove (Colombia and Venezuela) id (Indonesia) pl (Poland) us (United States of America) za (South Africa)
M^W	Other regions	rannexb (Rest of Annex B) roecd (Rest of OECD) row (Rest of World)
L	Electricity technologies	$L^T \cup L^S$

Symbol	Name	Content
L^F	Fuel-transforming technologies	biopower, coalpower, gaspower, lignitepower, oilpower, new_biopower, new_coalpower, new_gaspower, new_oilpower
L^G	Endogenous technologies	biopower, coalpower, gaspower, lignitepower, oilpower, pumped, reservoir, nuclear, wastepower, new_biopower, new_coalpower, new_gaspower, new_GSW, new_nuclear, new_oilpower, new_pumped, new_reservoir
L^H	New wind	new_GSW
L^P	Pumped storage hydro technologies	pumped, new_pumped
L^R	Reservoir hydro technologies	reservoir, new_reservoir
L^S	Special technologies	GSW, nuclear, reservoir, wastepower, new_GSW, new_nuclear, new_reservoir
L^T	Transforming technologies	biopower, coalpower, gaspower, lignitepower, oilpower, pumped, new_biopower, new_coalpower, new_gaspower, new_oilpower, new_pumped,
L^U	Nuclear technologies	nuclear, new_nuclear
L^W	Waste power	wastepower
L^{old}	Old technologies	biopower, coalpower, gaspower, GSW, lignitepower, nuclear, oilpower, pumped, reservoir, wastepower
L^{new}	New technologies	new_biopower, new_coalpower, new_gaspower, new_GSW, new_nuclear, new_oilpower, new_pumped, new_reservoir
S	Seasons	summer, winter
H	Times of day	H07 (07:00 – 09:00) H09 (09:00 – 13:00) H13 (13:00 – 16:00) H16 (16:00 – 20:00) H20 (20:00 – 00:00) H24 (00:00 – 07:00)
T	Time periods	$S \times H$
T_s	Season to period mapping	$\left\{(s,h) \in T \middle| h \in H\right\}$
J	Energy types	$J^E \bigcup J^F$
J^B	Biomass	biomass
J^C	Types of coal	coking coal, lignite, steam coal
J^E	Electricity	electricity
J^F	Fuels	biomass, coking coal, gas, lignite, oil, steam coal

Symbol	Name	Content
J^G	Gas	gas
J^L	Lignite	lignite
J^N	Non-coal fuels	biomass, gas, oil
J^O	Oil	oil
J^T	Traded types of coal	coking coal, steam coal
LJ	Technology–fuel correspondence	biopower.biomass, coalpower.steamcoal, gaspower.gas, lignitepower.lignite, oilpower.oil, pumped.electricity, new_biopower.biomass, new_coalpower.steamcoal, new_gaspower.gas, new_oilpower.oil, new_pumped.electricity
J_l	Technology to fuel mapping	$\{ j \in J \mid (l, j) \in LJ \}$
L_j	Fuel to technology mapping	$\{ l \in L^T \mid (l, j) \in LJ \}$
MM^E	Unique country pairs with electricity transmission	$\left\{ (m,n) \in M \times M \,\middle\vert\, \begin{array}{l} m \text{ and } n \text{ have existing or} \\ \text{potential electricity} \\ \text{transmission lines, } m > n \end{array} \right\}$
MM^G	Unique country pairs with gas transmission	$\left\{ \begin{array}{l} (m,n) \in M \times M \\ \vert m \text{ and } n \text{ have existing or} \\ \vert \text{potential pipelines, } m > n \end{array} \right\}$
Q	Consumers	$Q^E \cup Q^P$
Q^E	Intermediate demand	electricity_producers
Q^P	Private consumers	households, industry, transport
D^O	Nodes in demand tree	$D^C \cup D^K \cup D^P$
D^C	Model final commodities	GA, OI, SC, CC, LC, S07, S09, S13, S20, S24, W07, W09, W13, W20, W24
D^K	Nests	TO, R, RE, RG, RC, RO, EL, SU, WI, CO
D^P	Exogenous final commodities	P, PE, PG, PC, PO
D^G	Goods in demand tree	$D^O - \{\text{'TO'}\}$
D^{CJ}	Annual fuel demand correspondence	EL.electricity, GA.gas, OI.oil, SC.steamcoal, CC.cokingcoal, LC.lignite

Symbol	Name	Content
D^{CT}	Period electricity demand correspondence	WO7.WINTER.HO7, WO9.WINTER.HO9, W13.WINTER.H13, W16.WINTER.H16, W20.WINTER.H20, W24.WINTER.H24, SO7.SUMMER.HO7, SO9.SUMMER.HO9, S13.SUMMER.H13, S16.SUMMER.H16, S20.SUMMER.H20, S24.SUMMER.H24
D^{N}	Nest–good correspondence (CES tree)	TO.(P, R), R.(Re, Rg, Rc, Ro), Re.(Pe, EL), Rg.(Pg, GA), Rc.(Pc, CO), Ro.(Po, OI), EL.(SU, WI), SU.(S07, S09, S13, S16, S20, S24), WI.(W07, W09, W13, W16, W20, W24) CO.(SC, CC, LC)
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

Symbol	Name	Unit	GAMS name
Electricity			
ν_{ml}^{0}	Best electricity to fuel conversion factor	Mtoe/TWh	`ny0(m,l)`
ν_{ml}^{1}	Slope in electricity to fuel conversion factor function	Mtoe/(TWh* GW)	`ny1(m,l)`
ν_{ml}^{S}	Fuel use per unit start-up capacity	Mtoe / GW	`nyS(m,l)`
ξ_l^m	Share of total annual time available (1 – downtime)	–	`xi(m,l)`
$K_{ml}^{P\,0}$	Power capacity for old technology in base year $\mathring{a}_0$	GW	`KP(m,l)`
$K_{msl}^{I\,0}$	Inflow (energy availability) capacity in base year	TWh	`KI(m,s,l)`
$K_{ml}^{R\,0}$	Reservoir (energy transfer between seasons) capacity in base year	TWh	`KR(m,l)`
c_{ml}^{O}	Exogenous unit operating cost in electricity production	MUSD/ TWh	`MCO(m,l)`

Symbol	Name	Unit	GAMS name
c^{S}_{ml}	Exogenous unit start-up cost in electricity production	MUSD/ GW	`MCS(m,l)`
c^{M}_{ml}	Exogenous unit maintenance cost in electricity production	MUSD/ GW	`MCM(m,l)`
ρ^{I}_{msl}	Fixed coefficient between inflow capacity and power capacity	–	`rhoI(m,s,l)`
ρ^{R}_{ml}	Fixed coefficient between reservoir capacity and power capacity	–	`rhoR(m,l)`
c^{inv}_{ml}	Annualized unit capital costs	MUSD/GW	`CkP(m,l)`
c^{kP}_{ml}	Coefficient in exponential investment cost function	MUSD/GW	`CkP(m,l)`
c^{kP1}_{ml}	Coefficient in exponential investment cost function	–	`CkP1(m,l)`
ψ_{t}	Time in each period	Kh	`psi(t)`
ψ^{W}_{mt}	Expected share of time it blows in each period	–	`psiW(m,t)`
ρ_{mt}	Reserve power capacity demand	–	`rho(m,t)`
Supply of fuels			
K^{F}_{mj}	Domestic fuel extraction capacity	Mtoe	`KF(m,j)`
d^{m}_{jq}	Distribution unit cost, excluding cost of loss	MUSD/ (TWh or Mtoe)	`d(m,j,q)`
θ^{m}_{jq}	Loss adjustment in domestic energy distribution (1 – loss share)	–	`theta(m,j,q)`
Δ_{ml}	Annual rate of depreciation in power capacity	–	`Delta (m,l)`
$Conv^{m}_{j}$	Conversion factor for coal	Mtoe/Mt coal	`ConvOC(m,j)`
c^{L}_{m}	Exogenous landing costs; costs of transmission of gas from production node to consumption node in same country	MUSD/ Mtoe	`MCL(m)`
ac_{mj}	Constant in marginal cost function for extraction	TWh or Mtoe	`ac(m,j)`
bc_{mj}	Slope in marginal cost function for extraction	–	`bc(m,j)`
dc_{mj}	Parameter in marginal cost function for extraction	–	`dc(m,j)`
ec_{mj}	Parameter in marginal cost function for extraction	–	`ec(m,j)`
fc_{mj}	Parameter in marginal cost function for extraction	–	`fc(m,j)`

Symbol	Name	Unit	GAMS name
gc_{mj}	Parameter in marginal cost function for extraction	–	`gc(m,j)`
Demand			
a_{mj}^{X}	Constant in linear demand for fuel at world market	Mtoe	`ax(m,j)`
b_{mj}^{X}	Price coefficient in demand for fuel at world market	–	`bx(m,j)`
El_{mj}^{XI}	Income elasticity	–	`ElXI_oth(m,j)`
V_{mq}^{D0}	Demand income level in base year	–	`dV0(m,q)`
σ_{mqk}^{D}	Demand substitution parameter	–	`dsigma(m,q,k)`
a_{mqg}^{D}	Demand share parameter	–	`da(m,q,g)`
$\overline{x}_{mqc}^{D}$	Demand endowment parameter	–	`dXbar(m,q,c)`
$\upsilon_{må}$	GNP index	–	`upsilonAA(m)`
Trade			
c_{mn}^{CT}	Fixed transport cost of tradable coal exported from country *m* to country *n*	MUSD/Mt coal	`MCCT(m,n)`
c_{mn}^{CP}	Fixed port charge of tradable coal exported from country *m* to country *n*	MUSD/Mt coal	`MCCP(m,n)`
a_{nmj}^{TC}	Share parameter in price equation for tradable coal in export country	–	`aTC(n,m,j)`
σ_{mj}^{C}	Parameter in price equation for tradable coal in export country	–	`SigmaC(m,j)`
Δ^{E}	Annual rate of depreciation in transmission of electricity	–	`DeltaKE`
Δ^{G}	Annual rate of depreciation in transmission of natural gas	–	`DeltaKG`
θ_{mn}^{E}	Loss adjustment in international electricity transmission (1 – loss share)	–	`thetaE(m,n)`
θ_{mn}^{G}	Loss adjustment in international gas transmission (1 – loss share)	–	`thetaG(m,n)`
$K_{mn}^{E\ 0}$	International electricity transmission capacity in base year	GW	`KE(m,n)`
$K_{mn}^{G\ 0}$	International gas transmission capacity in base year	Mtoe	`KG(m,n)`
c_{mn}^{E}	Exogenous marginal cost in international electricity transmission	MUSD/ TWh	`MCE(m,n)`
c_{mn}^{G}	Exogenous marginal cost in international gas transmission	MUSD/ Mtoe	`MCG(m,n)`

Symbol	Name	Unit	GAMS name
c_{mn}^{KE}	Annualized unit capital costs for transmission of electricity	MUSD/GW	`CkE(m,n)`
c_{mn}^{KG}	Annualized unit capital costs for transmission of natural gas	MUSD/Mtoe	`CkG(m,n)`
General costs and technical parameters			
$\mathring{a}_0$	Model base year	–	`Aa0`
$\mathring{a}$	Solution year	–	`Aa`
Taxes and government instruments			
κ_{jq}^{m}	CO_2 tax	MUSD/ $MtCO_2$	`kappa(m,j,q)`
ε_{jq}^{m}	Energy tax	MUSD/ (TWh or Mtoe)	`Epsilon(m,j,q)`
χ_{jq}^{m}	SO_2 tax	MUSD/ $KtSO_2$	`Chi(m,j,q)`
τ_{jq}^{m}	Value-added tax rate	–	`Tau(m,j,q)`
Emissions			
ω_{j}^{m}	Fuel to CO_2 emission factor	$MtCO_2$/ Mtoe	`omega(m,j)`
σ_{j}^{m}	Own use of fuel in extraction (share)	–	`sigma(m,j)`
ς_{jq}^{m}	Fuel to SO_2 emission factor	$KtSO_2$/ Mtoe	`zeta(m,j,q)`
$adjust_m$	Net SO_2 emission in RAINS sectors not covered by LIBEMOD	$KtSO_2$/ Mtoe	`adjust(m)`

Table 3 Endogenous variables

Symbol	Name	Unit	GAMS name
Electricity			
C_{ml}^{P}	Variable costs for electricity producers	MUSD	
Π_{ml}^{E}	Profits of electricity producers	MUSD	`PPiE(m,l)`
x_{mjtl}^{E}	Use of energy input *j* in country *m* in period *t* by electricity technology *l*	Mtoe/TWh	
x_{mtq}^{E}	Period electricity demand	TWh	`Xe(m,t,q)`
y_{mtl}^{E}	Period electricity supply	TWh	`Ye(m,t,l)`

Symbol	Name	Unit	GAMS name
x_{mtl}^{DE}	Demand for electricity for pumped storage	TWh	`xDE(m,t,l)`
x_{ml}^{DF}	Demand for fuel from electricity producers	TWh	`xDF(m,l)`
P_{mtq}^{XE}	Period electricity user price	MUSD/ TWh	`Pxe(m,t,q)`
P_{mt}^{YE}	Period electricity supply price	MUSD/ TWh	`Pye(m,t)`
P_{ml}^{XF}	User price of fuel for electricity producers	MUSD/Mtoe	`pXF(m,l)`
K_{ml}^{P}	Power capacity in solution year $\mathring{a}$	GW	`KP(m,l)`
K_{ml}^{PM}	Maintained power capacity	GW	`KPM(m,l)`
K_{mtl}^{PR}	Reserve power capacity	GW	`KPr(m,t,l)`
K_{mtl}^{PS}	Start-up power capacity in excess of other period in season	GW	`KPS(m,t,l)`
ν_{tl}^{m}	Marginal electricity to fuel conversion factor	Mtoe/TWh	`ny(m,t,l)`
$\bar{\nu}_{tl}^{m}$	Average electricity to fuel conversion factor	Mtoe/TWh	`nybar(m,t,l)`
c_{mtl}^{p}	Marginal direct costs in electricity production	MUSD/ TWh	`MCP(m,t,l)`
R_{sl}^{m}	Reservoir filling at end of season	TWh	`R(m,s,l)`
λ_{ml}^{E}	Shadow price power capacity	MUSD/ GW	`lambdaE(m, l)`
π_{ml}	Shadow price of fuel use	MUSD/Mtoe	`pi(m,l)`
π_{msl}^{E}	Shadow price of electricity use in each season for pumped storage	MUSD/Mtoe	`piE(m,s,l)`
α_{msl}	Shadow price inflow capacity	MUSD/ TWh	`alpha(m,s,l)`
β_{msl}	Shadow price reservoir capacity	MUSD/ TWh	`beta(m,s,l)`
η_{ml}	Shadow price annual availability constraint	MUSD/ TWh	`eta(m,l)`
ϕ_{mtl}	Shadow price start-up day–night constraint	MUSD/ GW	`fi(m,t,l)`
μ_{mtl}^{M}	Shadow price maintained periodic electricity capacity	MUSD/ TWh	`myM(m,t,l)`
P_{mt}^{KPR}	Price of reserve power capacity	MUSD/GW	`PKPr(m,t)`
K_{ml}^{inv}	Investment in new technologies. Power capacity in new technologies	GW	`Kinv(m,l)`

Symbol	Name	Unit	GAMS name
K^{I}_{msl}	Inflow (energy availability) capacity	TWh	`KI(m,s,l)`
K^{R}_{ml}	Reservoir (energy transfer between seasons) capacity	TWh	`KR(m,l)`
γ_{mtq}	Period time share	–	`gamma(m,t,q)`
Supply of fuels			
C^{F}_{mj}	Variable costs for fuel suppliers	MUSD	
Π^{m}_{j}	Short-run profits of fuel suppliers	MUSD	`PPij(m,j)`
y^{m}_{j}	Annual energy supply	TWh or Mtoe	`Y(m,j)`
P^{Y}_{mj}	Annual energy supply price	MUSD/ (TWh or Mtoe)	`Py(m,j)`
P^{W}_{j}	World market annual energy price	MUSD/ Mtoe	`Pw(j)`
P^{C}_{mnj}	Price of tradable coal in country *n*, imported from country *m*	MUSD/Mt coal	`Pc(m,n,j)`
P^{B}_{mj}	Price of tradable coal in export country *m*	MUSD/Mt coal	`Pb(m,j)`
λ^{F}_{mj}	Shadow price annual energy capacity	MUSD/ Mtoe	`lambdaF(m,j)`
Demand			
x^{m}_{jq}	Annual energy demand	TWh or Mtoe	`X(m,j,q)`
x_oth_{mj}	Demand for oil and coal at the world market	Mtoe	`X_oth(m,j)`
P^{X}_{mjq}	Annual energy user price	MUSD/ (TWh or Mtoe)	`Px(m,j,q)`
U_{mqo}	Quantity level of nodes (Utility or goods)	–	`U(m,q,o)`
p^{D}_{mqo}	Price index of nodes.	–	`dP(m,q,o)`
V^{D}_{mq}	Demand income level in last year	–	`Vd(m,q,å)`
Trade			
Π^{ZG}_{mn}	Profits of owner of international gas transmission pipeline	MUSD	
Π^{ZE}_{mn}	Profits of owner of international electricity transmission line	MUSD	
z^{E}_{mnt}	Period electricity imported (sold from *m* to *n*)	TWh	`Ze(m,n,t)`

Symbol	Name	Unit	GAMS name
z^G_{mn}	Annual gas imported (sold from *m* to *n*)	Mtoe	`Zg(m,n)`
z^C_{nmj}	Import of tradable coal in country *m*, exported from country *n*	Mt coal	`Zc(n,m,j)`
z^B_{mj}	Gross imports of tradable coal in country *m*	Mt coal	`Zb(m,j)`
z^m_j	Net total imports of energy	TWh or Mtoe	`Z(m,j)`
μ^E_{mnt}	Shadow price international electricity transmission capacity	MUSD/ TWh	`myE(m,n,t)`
μ^G_{mn}	Shadow price international gas transmission capacity	MUSD/ Mtoe	`myG(m,n)`
K^E_{mn}	International electricity transmission capacity in last year	GW	`KE(m,n)`
K^G_{mn}	International gas transmission capacity in last year	Mtoe	`KG(m,n)`
$Kinv^E_{mn}$	Investment in electric transmission lines	MUSD	`KEinv(m,n)`
$Kinv^G_{mn}$	Investment in natural gas transmission lines	MUSD	`KGinv(m,n)`
Emissions			
CO_2^m	CO_2 emissions	$MtCO_2$	`CO2(m)`
SO_2^m	SO_2 emissions	$KtSO_2$	`SO2(m)`

3. Model relations

3.1. MARKETS

The model consists of a set M^N of endogenous countries, with markets for the set J of energy types: steam coal, coking coal, lignite, oil, gas, electricity and biomass. For electricity, there is a set of time 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. Some of these – the gas-exporting countries M^G – have a net supply of gas to the endogenous countries but with no endogenous modelling of natural gas demand behaviour.[1] There is no international trade in lignite and biomass (domestic markets only), whereas the markets for steam coal, coking coal and oil are world markets. Finally, all countries supply and demand steam coal, coking coal and oil but, for exogenous countries, the supply function for the international tradable coal types differ between the major coal exporting countries M^C and the other exogenous countries; that is, the gas exporting countries M^G and the remaining countries M^W.

3.2. FUEL SUPPLY

3.2.1 Natural Gas

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

$$C_{mj}^F = ac_{mj} y_j^m + \frac{bc_{mj}}{2} y_j^m y_j^m - dc_{mj} [K_{mj}^{F0} (1 - \frac{y_j^m}{K_{mj}^F}) \ln(1 - \frac{y_j^m}{K_{mj}^F}) + y_j^m], \qquad (1)$$
$$m \in M^N \cup M^G, j \in J^G \cup J^B,$$

where y_j^m is the quantity supplied, ac_{mj}, bc_{mj} and dc_{mj} are cost coefficients, and the available domestic capacity is K_{mj}^{F0}. Production is, however, constrained by the available domestic capacity:

$$y_j^m \le K_{mj}^F, m \in M^N \cup M^G, j \in J^G \cup J^B. \qquad (2)$$

1. Some of the exogenous countries also have a net supply of electricity to the endogenous countries, but none of the exogenous countries has endogenous modelling of electricity demand behaviour.

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

$$\Pi_j^m = P_{mj}^Y y_j^m - C_{mj}^F - c_m^L y_j^m, m \in M^N \cup M^G, j \in J^G \cup J^B, \tag{3}$$

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

$$\begin{gathered} \mathrm{L}_j^m = P_{mj}^Y y_j^m - C_{mj}^F - c_m^L y_j^m - \lambda_{mj}^F \left\{ y_j^m - K_{mj}^F \right\}, \\ m \in M^N \cup M^G, j \in J^G \cup J^B. \end{gathered} \tag{4}$$

The first-order necessary conditions (FOCs) for the maximization of (3) subject to (2) are:

$$\begin{gathered} P_{mj}^Y - ac_{mj} - bc_{mj} y_j^m - dc_{mj} \ln(1 - \frac{y_j^m}{K_{mj}^F}) - c_m^L - \lambda_{mj}^F \le 0 \perp \ y_j^m \ge 0, \\ m \in M^N \cup M^G, j \in J^G \cup J^B, \end{gathered} \tag{5}$$

$$y_j^m - K_{mj}^F \le 0 \perp \lambda_{mj}^F \ge 0, m \in M^N \cup M^G, j \in J^G \cup J^B, \tag{6}$$

where $a \le 0 \perp b \ge 0$ is shorthand for the complementarity slackness conditions $a \le 0, b \ge 0, ab = 0$ and $a \equiv \partial \mathrm{L} / \partial b$.[2] Because the maximand (3) is concave and the restriction (2) is convex, (5) and (6) are also sufficient maximum conditions.[3] In the long-run model, there is endogenous supply of natural gas from each model country; that is, both (5) and (6) apply.[4] In the short-run model, the supply of natural gas from each model country is exogenous, and hence only (6) applies.

3.2.2 Biomass

Biomass is used in order to produce electricity in biomass power plants in endogenous countries. Supply of biomass is modelled as the supply of natural gas; that is, (5) and (6) apply for $j \in J^B$ where (6) is applicable in the short-run version of the model, whereas (5) and (6) are applicable in the long-run version of the model. There is no international trade in biomass.

3.2.3 Oil

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

---

2. In the GAMS programming language, this is best entered as ‘Positive variable b’ ($b \ge 0$) in the declaration section, ‘ThisEquation.. 0=G=a’ ($a \le 0$) in the equations definition section, and ‘ThisEquation.b’ ($ab = 0$) in the model definition section.
3. For the endogenous countries, the extraction of fossil fuels is, in reality, set equal to capacity by setting extraction costs to zero.
4. Strictly speaking, (6) is not necessary, but it is included as it facilitates finding the equilibrium when the complete model is solved by GAMS.

$$C_{mj}^{F} = (ac_{mj} + \frac{bc_{mj}}{2} y_j^m) y_j^m, m \in M, j \in J^O. \tag{7}$$

Maximizing operating surplus (3) with respect to extracted quantity gives the FOC ($c_m^L = 0$):

$$P_{mj}^{Y} - ac_{mj} - bc_{mj} y_j^m \leq 0 \perp y_j^m \geq 0, m \in M, j \in J^O, \tag{8}$$

that is, the producer price of the fuel should equal marginal costs if positive production is profitable.

3.2.4 Coal

In both the short-run model and the long-run model, supply of each of the two types of internationally tradable coal (steam coal and coking coal) has, in general, a variable cost function of the form:

$$C_{mj}^{F} = ac_{mj} y_j^m + \frac{bc_{mj}}{2} y_j^m y_j^m + \frac{ec_{mj} fc_{mj}^{-gc_{mj}} \left(y_j^m\right)^{gc_{mj}+1}}{gc_{mj}+1}, \quad m \in M, j \in J^C, \tag{9}$$

where ec_{mj}, fc_{mj} and gc_{mj} are parameters.

Maximizing operating surplus (3) with respect to extracted quantity gives the FOC ($c_m^L = 0$):

$$p_{mj}^{Y} - ac_{mj} - bc_{mj} y_j^m - ec_{mj} \left(\frac{y_j^m}{fc_{mj}} \right)^{gc_{mj}} \leq 0 \perp y_j^m \geq 0, \quad m \in M, j \in J^C. \tag{10}$$

All non-model countries have coal supply functions given by (10) in both the short-run model and the long-run model.[5]

There is no international trade in lignite, and this is therefore only extracted in the model countries. For the model countries, one can choose between (i) exogenous supply and (ii) endogenous supply when the model is run. In the latter case, all three types of coal have a marginal cost function described by (10) but in a linear form as $ec = 0$.

---

5. Note that in several cases, $ec = 0$, for example for all countries in the long-run model.

3.3. ELECTRICITY SUPPLY

3.3.1 Costs

First, fuel-based electricity production requires the use of fuels. In addition to fuel costs, there are other inputs, which are assumed proportionate to production, with exogenous input prices, implying a constant unit operating cost c_{ml}^{O}. 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 (K_{ml}^{PM}), thus incurring a unit maintenance cost c_{ml}^{M} per unit of power (GW). The producer may also choose to vary the production of electricity between periods in each season. The producer will therefore incur a start-up cost, c_{ml}^{S}, measured pr. GW, each time the actual used capacity (K_{mtl}^{PS}) is increased. Adding up the cost components gives the electricity producers' variable cost equations of the form:

$$C_{ml}^{P} = \begin{cases} \sum_{t\in T} c_{ml}^{O} y_{mtl}^{E} + P_{ml}^{XF} x_{ml}^{DF} + c_{ml}^{M} K_{ml}^{PM} + \sum_{t\in T} c_{ml}^{S} K_{mlt}^{PS}, \\ \qquad m \in M^N, l \in L^F, \\ \\ \sum_{t\in T} c_{ml}^{O} y_{mtl}^{E} + \sum_{t\in T} P_{mtq}^{XE} x_{mtl}^{DE} + c_{ml}^{M} K_{ml}^{PM} + \sum_{t\in T} c_{ml}^{S} K_{mlt}^{PS}, \\ \qquad m \in M^N, l \in L^P, q \in Q^E, \\ \\ \sum_{t\in T} c_{ml}^{O} y_{mtl}^{E} + c_{ml}^{M} K_{ml}^{PM} + \sum_{t\in T} c_{ml}^{S} K_{mlt}^{PS}, \\ \qquad m \in M^N, l \in L^S, \end{cases} \tag{11}$$

where P_{ml}^{XF} is the user price of fuel in country *m* for technology *l*, and P_{mtq}^{XE} is the period-specific user price of electricity for electricity producers; that is, for pumped storage producers. Moreover, X_{ml}^{DF} is the demand for fuel in country *m* for technology *l*, and X_{mtl}^{DF} is the demand for electricity for pumped storage in country *m* in time period *t*.

Finally, producers may increase their capacity. Below we let c_{ml}^{inv} denote the annualized cost of investment per unit capacity; that is, investment costs are $c_{ml}^{inv} K_{ml}^{inv}$ where K_{ml}^{inv} is the increased capacity.

3.3.2 Revenues

Electricity producers sell power in the market to the price P_{mt}^{YE}. In addition to producing and selling power, an electricity producer can sell capacity (K_{mtl}^{PR}) to the system operator obtaining the price P^{KPR}_{mt} per unit of capacity sold (GW) in period *t*. The domestic system operator buys capacity in order to ensure that the domestic transmission network does not break down (see the discussion of relation (83) below), which may occur if demand exceeds the available amount of power.

3.3.3 Energy Efficiency

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

$$x^E_{mjtl} = \left(v^0_{ml} + v^1_{ml} \frac{y^E_{mtl}}{\psi_t} \right) y^E_{mtl}, m \in M^N, j = J_l, t \in T, l \in L^T, \quad (12)$$

which is a quadratic input requirement function giving the use of energy input *j* in country *m* in period *t* by technology *l*, x^E_{mjtl}, as an increasing function of the electricity produced, y^E_{mtl}, where v^0_{ml} and v^1_{ml} are parameters and ψ_t is the number of hours in period *t*. This transformation is mainly from fuels to electricity but applies also to the technology 'pumped storage', which uses electricity in one period to produce electricity in another. Because there is only one fuel used in each technology, the mapping $J_l = \{ j | (l, j) \in LJ \} \in J$ is single valued, although the opposite $L_j = \{ l | (l, j) \in LJ \} \subset L^T$ can be many valued. The mapping J_l assigns for each technology the (single) input used to produce electricity. For example, old gas-fired plants use natural gas. The mapping L_j assigns for each input which technologies use that input in order to produce electricity. For example, natural gas is used in both old and new gas-fired plants (old and new gas power are regarded as different technologies).

Let $\bar{v}^m_{tl}$ be the average conversion factor:

$$\bar{v}^m_{tl} = \frac{x^E_{mjtl}}{y^E_{mtl}} = v^0_{ml} + v^1_{ml} \frac{y^E_{mtl}}{\psi_t}, m \in M^N, j = J_l, t \in T, l \in L^T; \quad (13)$$

that is, $\bar{v}^m_{tl}$ is a linear function of used capacity, where production divided by the number of hours in period *t* (ψ_t) is the instantaneous capacity measured in GW. $\bar{v}^m_{tl}$ is the average use of input energy (Mtoe for the fossil fuels) per unit electricity produced (GWh); i.e., a combination of the inverse energy efficiency and a unit conversion factor. The marginal conversion rate is:

$$v^m_{tl} = \frac{\partial (x^E_{mjtl})}{\partial y^E_{mtl}} = v^0_{ml} + 2 v^1_{ml} \frac{y^E_{mtl}}{\psi_t}, m \in M^N, j = J_l, t \in T, l \in L^T, \quad (14)$$

representing the increase in fuel use for a marginal increase in electricity produced.[6]

3.3.4 Profit Maximization and Technology Constraints

Profits are given by:

$$\Pi_{ml}^{E} = \sum_{t \in T} (P_{mt}^{YE} y_{mtl}^{E} + P_{mt}^{KPR} K_{mtl}^{PR}) - C_{ml}^{P} - c_{ml}^{inv} K_{ml}^{inv}, m \in M^{N}, l \in L. \tag{15}$$

Each producer maximizes profits under a number of constraints. In general, the solution of a Kuhn–Tucker optimization problem returns the restrictions on the original problem complementary to an associated multiplier (see (2) and (6)). To shorten the exposition from this point onwards, restrictions on the optimization problem are given only in solution form, where the Kuhn–Tucker multiplier complementary to each constraint is also indicated.

Below we first present the constraints that apply for most technologies and then find the FOCs for these technologies. Next, we discuss (additional) constraints that apply to the other technologies and investigate the impact on the FOCs.

First, the maintained power capacity is constrained to be less than or equal to the total installed power capacity (K_{ml}^{P}):

$$K_{ml}^{PM} \leq K_{ml}^{P} \perp \lambda_{ml}^{E} \geq 0, m \in M^{N}, l \in L^{G}. \tag{16}$$

Second, 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. The power capacity in GW is transformed to electricity production capacity in TWh by multiplying by the number of hours in each period:

$$\begin{gathered} y_{mtl}^{E} \leq \psi_t (K_{ml}^{PM} - K_{mtl}^{PR}) \perp \mu_{mtl}^{M} \geq 0, m \in M^{N}, \\ t \in T, l \in L^{F} \cup L^{R} \cup L^{U} \cup L^{W}. \end{gathered} \tag{17}$$

All power plants need some downtime for technical maintenance. Hence, the total annual usage must be constrained to be less than the maintained instantaneous capacity by an availability factor (ξ_{l}^{m}):

$$\sum_{t \in T} y_{mtl}^{E} \leq \xi_{l}^{m} \sum_{t \in T} \psi_t K_{ml}^{PM} \perp \eta_{ml} \geq 0, m \in M^{N}, l \in L^{G}. \tag{18}$$

Next, as mentioned above, a start-up cost is incurred if (hourly) electricity production (y_{mtl}^{E} / ψ_t) varies between one period s and the previous period *u* in the same season. The start-up capacity must therefore satisfy the following requirement:

6. Note that the variable x_{mjtl}^{E} is not used in the model.

$$\left. y^E_{mtl} \middle/ \psi_t \right. - \left. y^E_{mul} \middle/ \psi_u \right. \leq K^{PS}_{mtl} \perp \phi_{mtl} \geq 0, \\ m \in M^N, t = (s,h) \in T, u = (s,h-1) \in T, l \in L^G. \tag{19}$$

Finally, increased capacity use may also require extra labour, as well as incurring other types of costs, which in our model is captured by c^S_{ml} in (11). Increased capacity use also requires extra fuel, which may be proportional to the fuel use of the marginal plant. We simplify by assuming constant additional fuel use, ν^S_{ml}, per unit start-up capacity. Total demand for fuel therefore cannot be less than the sum of the technical requirements stemming from direct electricity production ($\bar{\nu}^m_{tl} y^E_{mtl}$, see discussion above) and from start-up capacity ($\nu^S_{ml} K^{PS}_{mtl}$) in each period:

$$\sum_{t \in T} \left(\bar{\nu}^m_{tl} y^E_{mtl} + \nu^S_{ml} K^{PS}_{mtl} \right) \leq x^{DF}_{ml} \perp \pi_{ml}, m \in M^N, l \in L^F. \tag{20}$$

3.3.5 Old and New Plants

In general, we distinguish between two sectors. In the first sector ('old plants'), efficiency varies across plants, and capacity is already installed and cannot be increased through investment, but capacity depreciates over time:

$$K^P_{ml} = \left(1 - \Delta_{ml}\right)^{\mathring{a} - \mathring{a}_0} K^{P0}_{ml}, m \in M^N, l \in L^{old}, \tag{21}$$

where K^P_{ml} is the power capacity in the future year $\mathring{a}$, K^{P0}_{ml} is the power capacity in the base year $\mathring{a}_0$, and Δ_{ml} is the annual rate of depreciation.

In the other sector ('new plants'), there are no old plants, and hence production requires investment. For most technologies – the exceptions are reservoir hydro and wind power – the efficiency of new plants is assumed to be constant; that is, ν^1_{ml} is zero. The producers in this sector determine the stock of capital, which per definition equals investment:

$$K^P_{ml} = K^{inv}_{ml}, m \in M, l \in L^{new}. \tag{22}$$

3.3.6 Optimization

For convenience, we solve the optimization problem for both sectors simultaneously. However, one should bear in mind that in the short-run model, there is no investment; that is, (21) applies. In the long-run model, both types of producers solve their optimization problem; that is, producers with old plants use (21) whereas other producers use (22). Producers with old plants neglect the term $c^{inv}_{ml} K^{inv}_{ml}$ in (15) simply because they are not allowed to invest.

Fuel-transforming technologies

For fuel-transforming technologies (L^F), a producer maximizes profits (15) subject to (16)–(20). The Lagrangian of the producer, after insertion of (11) into (15) and (13) into (20), is as follows:

$$
\begin{aligned}
\mathrm{L}^E_{ml} = & \sum_{t\in T}\left(P^{YE}_{mt} y^E_{mtl} + P^{KPR}_{mt} K^{PR}_{mtl}\right) - \sum_{t\in T} c^O_{ml} y^E_{mtl} - P^{XF}_{ml} x^{DF}_{ml} - c^M_{ml} K^{PM}_{ml} \\
& - \sum_{t\in T} c^S_{ml} K^{PS}_{mlt} - c^{inv}_{ml} K^{inv}_{ml} - \lambda^E_{ml}\left\{K^{PM}_{ml} - K^P_{ml}\right\} \\
& - \sum_{t\in T} \mu^M_{mtl}\left\{y^E_{mtl} - \psi_t\left(K^{PM}_{ml} - K^{PR}_{mtl}\right)\right\} \\
& - \eta_{ml}\left\{\sum_{t\in T} y^E_{mtl} - \xi^m_l \sum_{t\in T}\psi_t K^{PM}_{ml}\right\} \\
& - \sum_{t\in T}\phi_{mtl}\left\{ y^E_{mtl}\big/\psi_t - y^E_{mul}\big/\psi_u - K^{PS}_{mtl}\right\} \\
& - \pi_{ml}\left\{\sum_{t\in T}\left((\nu^0_{ml} + \nu^1_{ml}\frac{y^E_{mtl}}{\psi_t}) y^E_{mtl} + \nu^S_{ml} K^{PS}_{mtl}\right) - x^{DF}_{ml}\right\},
\end{aligned}
\tag{23}
$$

$$t = (s,h) \in T, u = (s,h-1) \in T, m \in M^N, l \in L^F.$$

The FOC with respect to produced electricity in each period is:

$$
\begin{gathered}
P^{YE}_{mt} - c^O_{ml} - \mu^M_{mtl} - \eta_{ml} - \frac{1}{\psi_t}\left(\phi_{mtl} - \phi_{mul}\right) - \pi_{ml}\nu^m_{tl} \le 0 \perp y^E_{mtl} \ge 0, \\
m \in M^N, t = (s,h) \in T, u = (s,h+1) \in T, l \in L^F.
\end{gathered}
\tag{24}
$$

The FOC with respect to the demand for fuel from each power technology is:

$$\pi_{ml} - P^{XF}_{ml} \le 0 \perp x^{DF}_{ml} \ge 0, m \in M^N, l \in L^F. \tag{25}$$

The FOC with respect to the sale of reserve capacity is:

$$
\begin{gathered}
P^{KPR}_{mt} - \mu^M_{mtl}\psi_t \le 0 \perp K^{PR}_{mtl} \ge 0, \\
m \in M^N, t \in T, l \in L^F \cup L^U \cup L^R \cup L^P \cup L^W.
\end{gathered}
\tag{26}
$$

Furthermore, the FOC with respect to the maintained capacity is:

$$
\begin{gathered}
\sum_{t\in T}\psi_t\left\{\mu^M_{mtl} + \eta_{ml}\xi^m_l\right\} \le c^M_{ml} + \lambda^E_{ml} \perp K^{PM}_{ml}, \\
m \in M^N, l \in L^F \cup L^U \cup L^R \cup L^P \cup L^W,
\end{gathered}
\tag{27}
$$

whereas the FOC with respect to the start-up capacity is:

$$\phi_{mtl} \le c^S_{ml} + \pi_{ml}\nu^S_{ml} \perp K^{PS}_{mtl}, m \in M^N, t \in T, l \in L^F. \tag{28}$$

Finally, for the new technologies only, inserting from (22), the FOC with respect to power capacity (equal to investment) is:

$$c_{ml}^{inv} \geq \lambda_{ml}^{E} \perp K_{ml}^{P} \geq 0,\ m \in M^{N}, l \in L^{new} \cap (L^{F} \cup L^{U} \cup L^{P}). \qquad (29)$$

Nuclear power
In nuclear power plants, the time and cost that it takes to start up and shut down make it infeasible to vary the used capacity between time periods within a season. Thus, the start-up capacity is exogenously set at zero, $K_{mtl}^{PS} = 0;$ that is, capacity use is constrained to be equal in all time periods in a season. Note that restriction (19) does apply to nuclear, and hence (28) is not part of the FOCs of nuclear (as we do not optimize with respect to K_{mtl}^{PS}).

Like fuel-based technologies, nuclear also uses an input (uranium). However, because we do not model the uranium market, we implicitly assume that the price of uranium is fixed and let the parameter c_{ml}^{O} (l = 'nuclear') also include fuel costs. Hence, (20) does not apply to nuclear. Thus, the FOCs of nuclear are those of fuel-based technologies, except that (25) and (28) do not apply and (24) is modified to:

$$\begin{gathered} P_{mt}^{YE} - c_{ml}^{O} - \mu_{mtl}^{M} - \eta_{ml} - \frac{1}{\psi_t}\left(\phi_{mtl} - \phi_{mul}\right) \leq 0 \perp y_{mtl}^{E} \geq 0, \\ m \in M^{N}, t = (s,h) \in T, u = (s,h+1) \in T, l \in L^{U} \cup L^{H}. \end{gathered} \qquad (30)$$

Reservoir hydro
Reservoir hydropower producers have additional restrictions. First, the total use of water – that is, the total production of reservoir hydropower in season *s* plus the reservoir filling at the end of season *s* (R_{sl}^{m}) – should not exceed the total availability of water – that is, the sum of the reservoir filling at the end of the previous season and the seasonal inflow capacity (K_{msl}^{I}) expressed in energy units:

$$\sum_{t \in T_s} y_{mtl}^{E} + R_{sl}^{m} \leq R_{s-1,l}^{m} + K_{msl}^{I} \perp \alpha_{msl} \geq 0, m \in M^{N}, s \in S, l \in L^{R}, \qquad (31)$$

where T_s is the set of periods that fall in season *s*.

Second, reservoir filling at the end of each season *s* cannot exceed reservoir capacity K_{ml}^{R}.

$$R_{sl}^{m} \leq K_{ml}^{R} \ \perp \beta_{ms} \geq 0, m \in M^{N}, s \in S, l \in L^{R}. \qquad (32)$$

For the hydroelectric reservoir technology, the optimization problem involves two extra restrictions, (31) and (32), and one extra choice variable, R_{sl}^{m}, in each season. Moreover, for reservoir hydro there are three types of capacities; power capacity, inflow capacity and reservoir capacity. For *old* reservoir plants these capacities are given (and cannot be increased), but depreciate over time. Hence, in the (future) solution year $\mathring{a}_0$ the power capacity is given by (21), whereas the inflow (K^{I}_{msl}) and reservoir (K^{R}_{ml}) capacities are given by:

$$K^{I}_{msl} = \left(1-\Delta_{ml}\right)^{å-å_0} K^{I0}_{msl} \text{ , } m \in M^{N}, s \in S, l \in L^{R} \cap L^{old},$$
$$K^{R}_{ml} = \left(1-\Delta_{ml}\right)^{å-å_0} K^{R0}_{ml}, \ m \in M^{N}, l \in L^{R} \cap L^{old}, \tag{33}$$

where K^{I0}_{msl} and K^{R0}_{ml} are the given values in the base year.

For *new* reservoir plants there are no initial capacities, but it is possible to invest. Because of a lack of data, we assume that for new plants 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 for new plants power capacity per definition equals investment, these two relations are given by:

$$K^{I}_{msl} = \rho^{I}_{msl} K^{P}_{ml}, \ m \in M^{N}, s \in S, l \in L^{R} \cap L^{new}, \tag{34}$$

$$K^{R}_{ml} = \rho^{R}_{ml} K^{P}_{ml}, \ m \in M^{N}, l \in L^{R} \cap L^{new}, \tag{35}$$

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

The profit of the new reservoir hydro producer is:

$$\Pi^{E}_{ml} = \sum_{t \in T} \left(P^{YE}_{mt} y^{E}_{mtl} + P^{KPR}_{mt} K^{PR}_{mtl} \right) - C^{P}_{ml} - \frac{c^{kP}_{ml}}{c^{kP1}_{ml}} \left(e^{c^{kP1}_{ml} K^{inv}_{ml}} - 1\right), m \in M^{N}, l \in L^{R} \cap L^{new}. \tag{36}$$

From (36) it is straightforward to see that $c^{kP}_{ml} e^{c^{kP1}_{ml} K^{inv}_{ml}}$ is the marginal cost of investment, where c^{kP}_{ml} reflects the costs of investment in power capacity for the first (marginal) unit and c^{kP1}_{ml} is a parameter in the exponential function. Hence, we have assumed that annualized capital costs are increasing in power capacity (an exponential form), because a profit-maximizing reservoir producer will develop 'cheap' waterfall projects before moving on to more 'expensive' projects.

The Lagrangian of a reservoir hydro producer, taking into account the additional restrictions, is as follows:

$$
\begin{aligned}
\mathrm{L}_{ml}^{E} &= \sum_{t\in T}\left(P_{mt}^{YE} y_{mtl}^{E} + P_{mt}^{KPR} K_{mtl}^{PR}\right) - \sum_{t\in T} c_{ml}^{O} y_{mtl}^{E} - c_{ml}^{M} K_{ml}^{PM} \\
&- \sum_{t\in T} c_{ml}^{S} K_{mlt}^{PS} - \frac{c_{ml}^{kP}}{c_{ml}^{kp1}}\left(e^{c_{ml}^{kp1} K_{ml}^{inv}} - 1\right) - \lambda_{ml}^{E}\left\{K_{ml}^{PM} - K_{ml}^{P}\right\} \\
&- \sum_{t\in T} \mu_{mtl}^{M}\left\{y_{mtl}^{E} - \psi_t\left(K_{ml}^{PM} - K_{mtl}^{PR}\right)\right\} \\
&- \eta_{ml}\left\{\sum_{t\in T} y_{mtl}^{E} - \xi_l^{m}\sum_{t\in T}\psi_t K_{ml}^{PM}\right\} \\
&- \sum_{t\in T}\phi_{mtl}\left\{ y_{mtl}^{E}/\psi_t - y_{mul}^{E}/\psi_u - K_{mtl}^{PS}\right\} \\
&- \sum_{s\in S}\alpha_{msl}\left\{\sum_{t\in T_s} y_{mtl}^{E} + R_{sl}^{m} - R_{s-1,l}^{m} - K_{msl}^{I}\right\} - \sum_{s\in S}\beta_{msl}\left\{R_{sl}^{m} - K_{ml}^{R}\right\},
\end{aligned}
\tag{37}
$$

$$t = (s,h)\in T, u = (s,h-1)\in T, m\in M^{N}, l\in L^{R}.$$

The FOCs with respect to reserve capacity and maintained capacity are (26) and (27), and are identical to those for fuel-based production. On the other hand, the FOCs for produced electricity and start-up capacity now read as follows:

$$
\begin{gathered}
P_{mt}^{YE} - c_{ml}^{O} - \mu_{mtl}^{M} - \eta_{ml} - \frac{1}{\psi_t}\left(\phi_{mtl} - \phi_{mul}\right) - \alpha_{msl} \le 0 \perp y_{mtl}^{E} \ge 0, \\
m\in M^{N}, t=(s,h)\in T, u=(s,h+1)\in T, l\in L^{R}\cup L^{W},
\end{gathered}
\tag{38}
$$

$$\phi_{mtl} \le c_{ml}^{S} \perp K_{mtl}^{PS}, m\in M^{N}, t\in T, l\in L^{R}\cup L^{P}\cup L^{W}\cup L^{H}. \tag{39}$$

In addition, there is now a FOC with respect to optimal reservoir filling at the end of each season, relating the value of increased reservoir to the difference between water values in the two seasons:

$$\alpha_{m,s+1,l} \le \alpha_{msl} + \beta_{msl} \perp R_{sl}^{m} \ge 0, m\in M^{N}, s\in S, l\in L^{R}. \tag{40}$$

For ‘new reservoirs’ only, the FOC for optimal investment, after insertion of (34) and (35), must take into account rising investment costs and the value of additional inflow capacity and reservoir capacity, in addition to power capacity:

$$
\begin{gathered}
c_{ml}^{kP} e^{c_{ml}^{kp1} K_{ml}^{inv}} \ge \lambda_{ml}^{E} + \sum_{s\in S}\left\{\alpha_{msl}\rho_{msl}^{I} + \beta_{msl}\rho_{ml}^{R}\right\} \perp K_{ml}^{P} \ge 0, \\
m\in M^{N}, l\in L^{new}\cap L^{R}.
\end{gathered}
\tag{41}
$$

Pumped storage
For pumped storage, in each season, the total use of electricity must equal or exceed total production times the average conversion factor:[7]

$$\sum_{t\in T_s} \overline{v}_{tl}^{m} y_{mtl}^{E} \leq \sum_{u\in T_s} x_{mul}^{DE} \perp \pi_{msl}^{E}, m \in M^N, s \in S, l \in L^P, \tag{42}$$

thus modifying (20).

There is no direct correspondence between the electricity produced in period *t* and the electricity consumed in period *u*, only that the total for all times of day in the same season must be feasible. This presupposes that there is sufficient storage capacity to store as much water as needed each day. Second, the pumping capacity in each period must not be exceeded. We do not have separate data on pumping capacity, so for simplicity we assume that the maintained capacity is shared between pumping and power production activity, i.e., (17) changes to:

$$y_{mtl}^{E} + x_{mtl}^{DE} \leq \psi_t (K_{ml}^{PM} - K_{mtl}^{PR}) \perp \mu_{mtl}^{M} \geq 0, m \in M^N, t \in T, l \in L^P. \tag{43}$$

The FOCs with respect to reserve capacity, maintained capacity and investment are identical to those for fuel-based electricity production; that is, (26), (27) and (29), whereas the FOC with respect to start-up capacity is that of reservoir hydro (39). On the other hand, the FOC with respect to electricity production differs from that of both fuel-based power production and reservoir hydro:

$$\begin{gathered} P_{mt}^{YE} - c_{ml}^{O} - \mu_{mtl}^{M} - \eta_{ml} - \frac{1}{\psi_t}\left(\phi_{mtl} - \phi_{mul}\right) - \pi_{msl}^{E} v_{tl}^{m} \leq 0 \perp y_{mtl}^{E} \geq 0, \\ m \in M^N, t = (s,h) \in T, u = (s,h+1) \in T, l \in L^P. \end{gathered} \tag{44}$$

Finally, in each period, there is an additional FOC with respect to electricity used for pumping (replacing (25)):

$$\begin{gathered} \pi_{msl}^{E} - P_{mtq}^{XE} - \mu_{mtl}^{M} \leq 0 \perp x_{mtl}^{DE} \geq 0, \\ m \in M^N, t = (s,h) \in T, l \in L^P, q = \text{'electricity\_producers'}. \end{gathered} \tag{45}$$

Waste power
Waste power production of electricity is derived from the combustion of household and industrial waste. Each season, production is constrained by the available waste measured in energy units, i.e., implicitly assuming zero reservoir size:

$$\sum_{t\in T_s} y_{mtl}^{E} \leq K_{msl}^{I0} \perp \alpha_{msl} \geq 0, m \in M^N, s \in S, l \in L^W. \tag{46}$$

7. For pumped storage, fuel use is not related to a change in hourly electricity production, only to the level of production.

The Lagrangian is similar to that of reservoir hydro, except that there is no possibility of transferring waste between seasons ($R_{sl}^{m} = 0$), and hence the final term in (37) does not apply. Moreover, because of a lack of cost data, we simplify and assume that the available amount of waste is solely used by old waste power plants; that is, there is no investment. Hence, the FOCs for waste power are similar to those of reservoir hydro, except that (40) and (41) do not apply.

Renewables – wind power

The Geothermal, Solar and Wind (GSW) model technology has varying available energy capacity for each period and no storage possibilities. For old plants, production in each period is assumed to be fully exogenous. For new plants, we assume that *wind power* is the most cost-effective technology.

Wind power differs from most conventional power technologies in that the amount of electricity produced in TWh depends not only on the installed power capacity in GW, but also on the availability and speed of the wind at the physical location of the windmill. In this respect, it is similar to waste and reservoir power as one can calculate an inflow, or energy capacity, measurable in TWh in addition to power capacity in GW, where their quotient is the usable number of hours (measured in kh). However, while waste can transfer energy production between periods in the same season, and reservoir hydro can even transfer energy between different seasons by filling and tapping reservoirs, wind power must be produced when the wind blows. In each period, there is a (stochastic) distribution of the occurrence of different wind speeds, which for our purposes may be summarized as the expected value of the number of hours it blows in each period in each country. Assuming a constant expected share ψ_{mt}^{W} in each country and period, the expected number of hours of wind in each period is $\psi_{mt}^{W}\psi_{t}$, and the restriction on electricity produced (17) must be rewritten as follows:

$$y_{mtl}^{E} \leq \psi_{mt}^{W}\psi_{t}K_{ml}^{PM} \perp \mu_{mtl}^{M} \geq 0, m \in M^{N}, t \in T, l \in L^{H}. \tag{47}$$

Note that the amount of reserve power is dropped from this restriction because the stochastic nature of wind power makes it unavailable as reserve power; that is, $K_{mtl}^{PR} = 0$. [8]

The investment cost of *wind power* is probably an increasing function of electricity produced in the wind sector of each country, not because wind turbines themselves become more expensive as investment increases, but because the availability of area with advantageous wind conditions decreases with investment, i.e., ψ_{mt}^{W} should fall. As with reservoir power technology, this is modelled *as if* investment costs increase with installed power capacity. The full Lagrangian of the long-term profit-maximizing problem is then as follows:

8. Also the GSW producers are not allowed to sell reserve capacity to the system operator.

$$
\begin{aligned}
\mathrm{L}_{ml}^{E} = \sum_{t \in T} P_{mt}^{YE} y_{mtl}^{E} - \sum_{t \in T} c_{ml}^{O} y_{mtl}^{E} - c_{ml}^{M} K_{ml}^{PM} - \sum_{t \in T} c_{ml}^{S} K_{mlt}^{PS} \\
- \frac{c_{ml}^{kP}}{c_{ml}^{kp1}} (e^{c_{ml}^{kp1} K_{ml}^{inv}} - 1) - \lambda_{ml}^{E} \left\{ K_{ml}^{PM} - K_{ml}^{P} \right\} \\
- \sum_{t \in T} \mu_{mtl}^{M} \left\{ y_{mtl}^{E} - \psi_{mt}^{W} \psi_{t} K_{ml}^{PM} \right\} - \eta_{ml} \left\{ \sum_{t \in T} y_{mtl}^{E} - \xi_{l}^{m} \sum_{t \in T} \psi_{t} K_{ml}^{PM} \right\} \\
- \sum_{t \in T} \phi_{mtl} \left\{ y_{mtl}^{E} / \psi_{t} - y_{mul}^{E} / \psi_{u} - K_{mtl}^{PS} \right\},
\end{aligned}
\tag{48}
$$

$$
m \in M^{N}, t = (s,h) \in T, u = (s,h+1) \in T, l \in L^{H}.
$$

The FOCs with respect to start-up capacity are similar to those of reservoir hydro, (39). The FOC with respect to electricity production is given by (30), whereas the FOCs with respect to maintained capacity and investments are as follows:

$$
\sum_{t \in T} \psi_{t} \left\{ \psi_{mt}^{W} \mu_{mtl}^{M} + \eta_{ml} \xi_{l}^{m} \right\} \le c_{ml}^{M} + \lambda_{ml}^{E} \perp K_{ml}^{PM}, m \in M^{N}, l \in L^{H}, \tag{49}
$$

$$
c_{ml}^{kP} e^{c_{ml}^{kp1} K_{ml}^{inv}} \ge \lambda_{ml}^{E} \perp K_{ml}^{P} \ge 0, \ m \in M^{N}, l \in L^{H}. \tag{50}
$$

Note that, in general, the start-up costs for wind power are assumed to be zero (thus $\phi_{mtl} = \phi_{mul} = 0$), and the downtime requirement is never binding because the total wind share is always less than the possible up time.

3.4. DEMAND

3.4.1 End-User Demand in Endogenous Countries

Each private consumer $q \in Q^{P}$ in each endogenous country $m \in M^{N}$ has a utility level $U_{mq'TO'}$, which is the quantity level of the top node in a constant elasticity of substitution (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 $c \in D^{C} \bigcup D^{P}$. The nodes each have an associated quantity level U_{mqo} and price level or index p_{mqo}^{D}. 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, defining the quantity level of the good.

$$
U_{mqk} = \left[\sum_{g \in D_{k}^{N}} a_{mqg}^{D\ \frac{1}{\sigma_{mqk}^{D}}} U_{mqg}^{\frac{\sigma_{mqk}^{D}-1}{\sigma_{mqk}^{D}}} \right]^{\frac{\sigma_{mqk}^{D}}{\sigma_{mqk}^{D}-1}}, m \in M^{N}, q \in Q^{P}, k \in D^{K}. \tag{51}
$$

The chosen nest structure allows for limited substitution possibilities between electricity in different time periods within and between each season. 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 commodity P. The complementary goods (P, PE, PG, PC, PO) play no other role in the model and have prices set exogenously at unity.

To allow for income elasticities different from unity, the end users have an exogenous endowment of each commodity $\overline{x}^D_{mqc}$. The consumers are assumed to maximize utility, given a budget constraint reflecting exogenous income, endowments and commodity prices.

$$\begin{gathered}\text{Max} \quad U_{\text{mq;'TO'}}, s.t. \sum_{c\in D^C \cup D^P} p^D_{mqc}\left(U_{mqc} - \overline{x}^D_{mqc}\right) \le V^D_{mq}, \\ \forall m \in M^N, q \in Q^P.\end{gathered} \tag{52}$$

Inserting the nest function (51), an indirect utility function is derived:

$$U_{\text{mq;'TO'}} = \left(V^D + \sum_{c\in D^c} p^D_c \overline{x}^D_c\right) \Big/ p^{\text{D}}_{\text{mq'TO'}}, m \in M^N, q \in Q^P, \tag{53}$$

which is simply the net income divided by the top-level price index.

Each nest price index is of the general form:

$$p^D_{mqk} = \left[\sum_{g\in D^N_k} a^D_{mqg} P^{D\;\;1-\sigma^D_{mqk}}_{mqg}\right]^{\frac{1}{1-\sigma^D_{mqk}}}, m \in M^N, q \in Q^P, k \in D^K, \tag{54}$$

(54) and the final demand prices of model commodities and exogenous commodities:

$$\begin{gathered} p^D_{mqc} = 1, m \in M^N, q \in Q^P, c \in D^P, \\ p^D_{mqc} = P^X_{mjq}, m \in M^N, q \in Q^P, (c, j) \in D^{CJ}, \\ p^D_{mqc} = P^{XE}_{mtq}, m \in M^N, q \in Q^P, (c,t) \in D^{CT}, \end{gathered} \tag{55}$$

determine all node prices.

The quantity levels of goods are then given by:

$$U_{mqg} = a^D_{mqg}\left[\frac{P^D_{mqk}}{P^D_{mqg}}\right]^{\sigma^D_{mqk}} U_{mqk}, m \in M^N, q \in Q^P, (g,k) \in D^N, \tag{56}$$

which, together with the top-level quantity (i.e., utility) from (53) determines the final demand for the annual energy commodities and period electricity commodities:

$$x_{jq}^{m} = U_{mqc} - \overline{x}_{mqc}^{D}, m \in M^{N}, q \in Q^{P}, (c, j) \in D^{CJ}, \tag{57}$$

$$x_{mtq}^{E} = U_{mqc} - \overline{x}_{mqc}^{D}, m \in M^{N}, q \in Q^{P}, (c, t) \in D^{CT}. \tag{58}$$

Finally, for all end users in all countries, the income level in a future year *å* is given by:

$$V_{mq}^{D} = V_{mq}^{D0}\, \upsilon_{må}, m \in M, \tag{59}$$

where $\upsilon_{må}$ is an index showing the increase in income in country *m* between the base year and year *å*.

3.4.2 Intermediate Demand in Endogenous Countries

In addition to final demand, electricity producers represent intermediate demand; see (25) with respect to fuel demands (fossil-fuel-based production and biomass power) and (45) with respect to electricity (pumped storage). The total annual demand for fuels from electricity producers is as follows:

$$x_{jq}^{m} = \sum_{l \in L_j} x_{ml}^{DF}, m \in M^{N}, j \in J^{F}, q \in Q^{E}. \tag{60}$$

Total demand for electricity from old and new pumped storage in each time period is:

$$x_{mtq}^{E} = \sum_{l \in L_j} x_{mtl}^{DE}, m \in M^{N}, j = J^{E}, t \in T, q \in Q^{E}, \tag{61}$$

whereas total annual demand for electricity for all consumer groups adds up the period demands in (58) and (61) respectively.

$$x_{jq}^{m} = \sum_{t \in T} x_{mtq}^{E}, m \in M^{N}, j \in J^{E}, q \in Q. \tag{62}$$

3.4.3 Exogenous Countries

Demand for coking coal, steam coal and oil by end users in exogenous countries, x_oth_{mj}, is a linear function, modified by an income elasticity term in the long-run version:

$$x\_oth_{mj} = \upsilon_{må}^{El_{mj}^{XI}} \left[a_{mj}^{X} + b_{mj}^{X} P_{mj}^{Y} \right], m \in M^{G} \cup M^{C} \cup M^{W}, \quad j \in J^{T} \cup J^{O}, \tag{63}$$

where El_{mj}^{XI} is the income elasticity, and $\upsilon_{må}$ is an index for predicted income for future year *å*.

3.5. INTERNATIONAL ENERGY TRADE

3.5.1 Gas and Electricity

Gas and electricity can be traded via international pipelines or transmission lines. Each pipeline/transmission line is owned by a single agent. Focusing first on *natural gas*, let m and n be two countries, and let z_{mn}^G be the gas exported from m to n, measured at the node of the importing country n. Because there is some loss in transmission (θ_{mn}^G), the quantity z_{mn}^G / θ_{mn}^G is exported from country m. The pipeline owner, as a price taker, transports gas as long as there is a positive difference between (i) the purchasing price in the import country, $P_{n'gas'}^Y$, and (ii) the loss-adjusted purchasing value in the exporting country, $P_{m'gas'}^Y / \theta_{mn}^G$, less exogenous costs of transmission, c_{mn}^G. Hence, all arbitrage possibilities are exploited. The pipeline can be used either for imports to country n from country m or for exports from country n to country m. In addition, the owner can expand the initial capacity of the pipeline, K_{mn}^G, through investments, $Kinv_{mn}^G$. Hence, the profits of the owner of the pipeline between country m and n are:

$$\Pi_{mn}^{ZG} = \left[P_{nj}^Y - \frac{P_{mj}^Y}{\theta_{mn}^G} - c_{mn}^G \right] z_{mn}^G + \left[P_{mj}^Y - \frac{P_{nj}^Y}{\theta_{nm}^G} - c_{nm}^G \right] z_{nm}^G - c_{mn}^{KG} Kinv_{mn}^G, \quad j = \text{'gas'},\ (m,n) \in MM^G, \tag{64}$$

where c_{mn}^{KG} is the annualized (unit) capital cost for expansion of natural gas transmission lines. Moreover, the owner faces the following constraints:

$$z_{mn}^G - z_{nm}^G \le K_{mn}^G \perp \mu_{mn}^G \ge 0, \quad (m,n) \in MM^G \text{ or } (n,m) \in MM^G. \tag{65}$$

That is, net trade in either direction cannot exceed total pipeline capacity, K_{mn}^G, which is the sum of (depreciated) initial capacity and investments in capacity:

$$K_{mn}^G = K_{nm}^G = (1-\Delta^G)^{å-å_0} K_{mn}^{G0} + Kinv_{mn}^G, (m,n) \in MM^G, \tag{66}$$

where Δ^G is the annual rate of depreciation for natural gas transmission lines, and the first equality ensures that the capacity is the same in both directions. The shadow price μ_{mn}^G can be interpreted as the tariff (in excess of c_{mn}^G) that ensures that demand for transport services does not exceed the available capacity. Note that (65) is valid for trade between m and n in both directions (two inequalities).

The FOCs of the transmission pipeline owners with respect to trade in either direction are given by the following:

$$P^Y_{nj} - \frac{P^Y_{mj}}{\theta^G_{mn}} - c^G_{mn} - \mu^G_{mn} + \mu^G_{nm} \leq 0 \perp z^G_{mn} \geq 0, \qquad (67)$$
$$(m,n) \in MM^G \text{ or } (n,m) \in MM^G.$$

The relationship between net gas imports and the gross bilateral gas trade quantities is as follows:

$$z^m_{'gas'} = \sum_{n \in M} \left\{ z^G_{nm} - \frac{z^G_{mn}}{\theta^G_{mn}} \right\}, m \in M. \qquad (68)$$

Because investments increase capacity in both directions, the FOC for investment in transmission is given by:

$$\mu^G_{mn} + \mu^G_{nm} \leq c^{KG}_{mn} \perp Kinv^G_{mn} \geq 0, (m,n) \in MM^G, \qquad (69)$$

that is, capital costs should be compared with two shadow prices (one in each direction), of which at most one can be positive in any equilibrium.

The international transportation of *electricity* is modelled in the same way as natural gas. Hence, the profits of the owner of the line between country m and n are:

$$\Pi^{ZE}_{mn} = \sum_{t \in T} \left\{ \left[P^{YE}_{nt} - \frac{P^{YE}_{mt}}{\theta^E_{mn}} - c^E_{mn} \right] z^E_{mnt} + \left[P^{YE}_{mt} - \frac{P^{YE}_{nt}}{\theta^E_{nm}} - c^E_{nm} \right] z^E_{nmt} \right\}$$
$$-c^{KE}_{mn} Kinv^E_{mn}, \qquad (70)$$
$$(m,n) \in MM^E,$$

where c^{KE}_{mn} is the annualized (unit) capital cost for the expansion of the international electricity transmission lines. Moreover, the owner faces the following constraint:

$$z^E_{mnt} - z^E_{nmt} \leq \psi_t K^E_{mn} \perp \mu^E_{mnt} \geq 0, \qquad (71)$$
$$t \in T, (m,n) \in MM^E \text{ or } (n,m) \in MM^E.$$

In (71), K^E_{mn} is the sum of (depreciated) initial capacity and investments in capacity:

$$K^E_{mn} = (1 - \Delta^E)^{\mathring{a} - \mathring{a}_0} K^{E\ 0}_{mn} + Kinv^E_{mn}, (m,n) \in MM^E, \qquad (72)$$

where Δ^E is the annual rate of depreciation for electricity transmission lines.

The FOCs of the transmission line owners for trade in either direction in any period are given by:

$$P_{nt}^{YE} - \frac{P_{mt}^{YE}}{\theta_{mn}^{E}} - c_{mn}^{E} - \mu_{mnt}^{E} + \mu_{nmt}^{E} \le 0 \perp z_{mnt}^{E} \ge 0,$$
$$t \in T, (m,n) \in MM^{E} \text{ or } (n,m) \in MM^{E}, \tag{73}$$

whereas the FOC for investment in electricity transmission is given by:

$$\sum_{t \in T} \psi_t (\mu_{mnt}^{E} + \mu_{nmt}^{E}) \le c_{mn}^{KE} \perp Kinv_{mn}^{E} \ge 0, (m,n) \in MM^{E}. \tag{74}$$

(74) takes into account the fact that not only does investment increase capacity in both directions, but also that the increased capacity can be utilized in all periods.

3.5.2 Coal

Coal imports to endogenous countries of the traded coal types steam coal and coking coal are based on the node price in the exporting country (P_{mj}^{B}) plus transport costs and port charges, all calculated as MUSD/Mt coal:

$$P_{mnj}^{C} = P_{mj}^{B} + c_{mn}^{CT} + c_{mn}^{CP}, m \in M, n \in M^{N}, j \in J^{T}, \tag{75}$$

where c_{mn}^{CT} is the fixed transport cost from country *m* to country *n* in MUSD/Mt coal, and c_{mn}^{CP} is the corresponding port charge.

The imports to non-endogenous countries are exogenously fixed. If imports to endogenous countries are positive, the importing country's node price must equal a CES price index of the import price from each exporting country:

$$p_{mj}^{B} = \left[\sum_{n \in M} a_{nmj}^{TC} {P_{nmj}^{C}}^{1-\sigma_{mj}^{C}} \right]^{\frac{1}{1-\sigma_{mj}^{C}}}, m \in M^{N}, j \in J^{T}, \tag{76}$$

and the import demanded from each exporting country by each importing country is the total gross import multiplied by a price-responsive share function:

$$z_{nmj}^{C} = a_{nmj}^{TC} \left[\frac{P_{mj}^{B}}{P_{nmj}^{C}} \right]^{\sigma_{mj}^{C}} z_{mj}^{B}, m \in M^{N}, n \in M, j \in J^{T}. \tag{77}$$

The constant *a* is a share parameter, which is only positive for country pairs *(n,m)* that have trade in the base year.[9] One important implication of this Armington (1969) formulation is that no trade can take place between countries that were not already trading in the base year. Net imports to endogenous countries in Mtoe are related to gross imports and bilateral exports in MT coal by:

9. In the GAMS code, the number of equations is restricted by a country correspondence, MMC, paralleling gas and electricity above.

$$z_j^m = Conv_j^m \left[z_{mj}^B - \sum_{n \in M} z_{mnj}^C \right], \; m \in M^N, j \in J^T, \tag{78}$$

where the conversion factor is specific to each country and coal type. For the exogenous countries, net coal imports are simply the sum of the bilateral imports minus bilateral exports, converted to Mtoe.

$$z_j^m = Conv_j^m \sum_{n \in M} \left[z_{nmj}^C - z_{mnj}^C \right], m \in M^G \cup M^C \cup M^W, j \in J^T. \tag{79}$$

Finally, the price in MUSD/Mt coal is related to the price in MUSD/Mtoe (P_{mj}^Y) by the following conversion factor.

$$P_{mj}^B = Conv_j^m P_{mj}^Y, m \in M, j \in J^T. \tag{80}$$

3.6. EQUILIBRIUM

3.6.1 Endogenous Countries

In each endogenous country, the consumed quantities are, in equilibrium, equal to the quantities delivered at a central node, adjusted by a fixed proportion in distribution losses. Summing over consumers, suppliers and international trading partners gives the following domestic market equilibrium conditions for all fossil fuels and biomass:

$$\sum_{q \in Q} \frac{x_{jq}^m}{\theta_{jq}^m} \leq y_j^m + z_j^m \perp P_{mj}^Y \geq 0, m \in M^N, j \in J^F, \tag{81}$$

where θ_{jq}^m denotes the loss adjustment in domestic energy distribution (1 – loss share). The equilibrium condition is expressed as a complementarity between non-negative excess supply and non-negative prices, but excess supply is zero, and prices are positive, for all realistic scenarios in this model.

A similar condition applies for electricity:

$$\sum_{q \in Q} \frac{x_{mtq}^E}{\theta_{jq}^m} \leq \sum_{l \in L} y_{mtl}^E + \sum_{n \in M} \left\{ z_{nmt}^E - \frac{z_{mnt}^E}{\theta_{mn}^E} \right\} \perp P_{mt}^{YE} \geq 0, \quad j = \text{'electricity'}, m \in M^N, t \in T. \tag{82}$$

In each endogenous country, the domestic system operator has to ensure that there is reserve power capacity available, which is imposed as a percentage, ρ_{mt}, of maintained capacity. The demand for reserve power is the result of a social optimization problem not modelled here, and the price of reserve power capacity enters complementarily to the reserve capacity constraint so that it will only be positive if the constraint is binding.

$$\rho_{mt} K_{ml}^{PM} \le \sum_{l \in L^G} K_{mtl}^{PR} \perp P_{mt}^{KPR} \ge 0, m \in M^N, t \in T. \tag{83}$$

3.6.2 Exogenous Countries

For exogenous countries, the domestic market condition for fossil fuels, except biomass and lignite, which only appear in the endogenous countries, is as follows:

$$\begin{gathered} x\_oth_{mj} - z_j^m \le y_j^m \perp P_{mj}^Y \ge 0, m \in M^C \cup M^G \cup M^W, \\ j \in J^G \cup J^O \cup J^T. \end{gathered} \tag{84}$$

3.6.3 World Market

In the model, oil is traded in a world market (trade takes place in a single node), whereas either all other commodities are traded bilaterally or there is no international trade. The equilibrium condition in the oil market requires that the sum of net imports of oil does not exceed zero:

$$\sum_{m \in M} z_j^m \le 0 \perp P_j^W \ge 0, j \in J^O. \tag{85}$$

The complementarity condition ensures that excess supply is only feasible with a zero price. The net imports to each country are the quantities necessary to ensure price equality on domestic and international markets:

$$P_{mj}^Y = P_j^W, m \in M, j \in J^O. \tag{86}$$

3.6.4 User Prices

User prices, in addition to reflecting the producer price adjusted for domestic losses (P_{mj}^Y / θ_{jq}^m), include non-loss distribution costs d_{jq}^m, energy excise taxes ε_{jq}^m, carbon taxes κ_{jq}^madjusted for the carbon content of each fuel ω_j^m, SO_2 taxes χ_{jq}^m adjusted for the carbon content of the fuel ς_{jq}^m, and value-added tax τ_{jq}^m. The user prices for fossil fuels and biomass are as follows:

$$\begin{gathered} P_{mjq}^X = \left[\frac{1}{\theta_{jq}^m} P_{mj}^Y + d_{jq}^m + \varepsilon_{jq}^m + \omega_j^m \kappa_{jq}^m + \varsigma_{jq}^m \chi_{jq}^m \right] (1 + \tau_{jq}^m), \\ m \in M^N, j \in J^F, q \in Q. \end{gathered} \tag{87}$$

For electricity producers, the fuel input price is simply the user price of the fuel used by that producer.

$$P_{ml}^{XF} = P_{mjq}^X, m \in M^N, j = J_l, l \in L^F, q \in Q^E. \tag{88}$$

As for fuels, the period-specific user price for electricity is as follows:

$$P_{mtq}^{XE} = \left[\frac{1}{\theta_{jq}^{m}} P_{mt}^{YE} + d_{jq}^{m} + \varepsilon_{jq}^{m} + \omega_{j}^{m}\kappa_{jq}^{m} + \varsigma_{jq}^{m}\chi_{jq}^{m} \right](1+\tau_{jq}^{m}),$$
$$j = \text{'electricity'}, m \in M^{N}, t \in T, q \in Q. \quad (89)$$

The user price of annual electricity is:

$$P_{mjq}^{X} = \sum_{t\in T} \gamma_{mtq} P_{mtq}^{XE}, m \in M^{N}, j \in J^{E}, q \in Q, \quad (90)$$

where the period timeshare for each demand sector is determined by:

$$\gamma_{mtq} \sum_{u\in T} x_{muq}^{E} = x_{mtq}^{E}, m \in M^{N}, q \in Q. \quad (91)$$

In the basic formulation, (90) and (91) do not enter the simultaneous model because only period electricity prices determine the supply and demand of electricity.

3.7. EMISSIONS

The emission of CO_2 in each country is the sum of the use of each energy form and the associated emission coefficient, plus a small amount of emissions reflecting own use σ_{j}^{m} of the fuel in extraction:

$$\mathrm{CO}_2^{\mathrm{m}} = \sum_{j\in J}\sum_{q\in Q} \omega_{j}^{m} x_{jq}^{m} + \sum_{j\in J} \omega_{j}^{m}\sigma_{j}^{m} y_{j}^{m}, m \in M^{N}, \quad (92)$$

$$\mathrm{CO}_2^{\mathrm{m}} = \sum_{j\in J} \omega_{j}^{m} x\_oth_{j}^{m} + \sum_{j\in J} \omega_{j}^{m}\sigma_{j}^{m} y_{j}^{m}, m \in M^{G} \cup M^{C} \cup M^{W}. \quad (93)$$

The emissions of SO_2 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 (see Alcamo et al., 1990) but not in LIBEMOD ($adjust_m$):

$$\mathrm{SO}_2^{\mathrm{m}} = \sum_{j\in J}\sum_{q\in Q} \varsigma_{jq}^{m} x_{jq}^{m} + adjust_{m}, m \in M^{N}. \quad (94)$$

In the basic model, (92) and (94) enter sequentially.

4. Model Data

In this chapter, 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 we describe the data used in the long-run version. The base year of the model is 2000, and all prices and costs are measured in 2000 USD.

4.1. END-USER DEMAND

There are 17 model countries; Austria, Belgium (including Luxembourg), Denmark, Finland, France, Germany, Greece, Ireland, Italy, Japan, Netherlands, Norway, Portugal, Spain, Sweden, Switzerland and United Kingdom (UK). In addition, there is supply and demand for some goods in Algeria, Australia, Canada, China, COVE (Colombia and Venezuela), Indonesia, Poland, Russia, South Africa, Ukraine, the United States of America, 'Rest of Annex B' (Bulgaria, Estonia, Hungary, Iceland, Japan, Latvia, Lithuania, Croatia, New Zealand, Romania, Slovakia, Slovenia and Czech Republic),[10] 'Rest of the OECD' (Korea, Mexico and Turkey), and ROW (rest of world). That is, all countries in the world are included.

4.1.1 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 six periods (starting at 07:00, 09:00, 13:00, 16:00, 20:00 and 00:00). The length of each period is specified to capture demand variations throughout the day. By assumption, each season is six months long.

4.1.2 Quantities

Demand in each model country is divided into three end-user groups or sectors, denoted 'household', 'industry' and 'transport'. Household demand covers services and agriculture in addition to households. Base year demand for fossil fuels, except coal, is taken from *Energy Balances of OECD Countries, 1999–2000* (IEA, 2002b), and is measured in Million tons of oil equivalent (Mtoe). In the statistics, household demand corresponds to 'Other sectors'. Industry demand is then taken as total fuel consumption (TFC) minus household demand and end-use demand from the transport sector plus use in 'gas works', 'coal transformation' and 'other transformation'. The demand for fossil fuels in electricity production is taken from 'Electricity plants' plus 'Combined Heat and Power (CHP) plants'. For all three types of coal, the base year demand is taken from *Energy Statistics of OECD Countries, 1999–2000* (IEA, 2002c).

Base year demand for electricity is taken from *Energy Statistics of OECD Countries, 1999–2000* (IEA, 2002c), and is measured in terawatt-hours (TWh). In the statistics,

1. Annex B countries are signatories to the Kyoto agreement that have emission limits imposed by the agreement.

household demand is taken from ‘Other sectors’, whereas industry demand is from ‘Final consumption’ less household demand. For both end-user groups, the use of heating is added after converting heat to electricity equivalents (see the discussion below on supply of electricity).

In order to calibrate the demand for electricity, the annual consumption quantities are split into period quantities according to the base year shares of electricity consumption. These are partly based on UCTE (2001), which gives the monthly quantities of electricity consumed (TWh) and the consumption load (MW) at 3:00 a.m. and 11:00 a.m. on the third Wednesday of each month, and partly from industry sources. For the Nordic countries, the numbers are based on actual values (see www.nordpool.com).

4.1.3 Prices and Taxes

Base year prices and taxes are mainly taken from *Energy Prices and Taxes, Third Quarter 2002* (IEA, 2002d), and so are exchange rates from the various national currencies to USD.

Prices after tax for fossil fuels are mainly taken from Table 2 in IEA (2002d) (national currencies per toe). However, the price of steam coal for households is taken from Table 1 (per tonne) and converted to toe. The price of coking coal to households is set equal to price of coking coal to industry, while for lignite, the household price is set to 70 per cent of the price of steam coal. For industry, the price of oil is a weighted average of the prices of light and heavy fuel oil taken from Table 2. Finally, the price of oil to transport is a weighted average of the prices on gasoline and diesel, which are found in Table 1 under ‘Automotive Diesel for Commercial Use’ and ‘Premium Unleaded (95 RON) Gasoline’. The quantities are from IEA (2002c).

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

In the base year, there were CO_2 taxes in four Nordic countries in the model (Denmark, Finland, Norway and Sweden). 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 TJ fuel (Simmons, 2002) and between TJ fuel and toe (BP, 2006). The resulting values (measured as CO_2 per toe) are 3.99 (steam coal), 3.96 (coking coal), 4.24 (lignite), 3.15 (oil) and 2.35 (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 2000. 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 heuristics.

The statistics in IEA (2002d) start in general in 1991, and prices and taxes are therefore given for earlier years than 2000 (the base year). For missing 2000 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 (2002d). Moreover, we assume that excise taxes and VAT rates are constant over time, unless known otherwise.

Where no historical prices are available, we have sometimes used the same prices for the industry as 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 no information is available, excise taxes are set equal to zero.

4.1.4 Direct Price Elasticities

Our aim is to find short-term and long-term direct price elasticities for coal (aggregated over the three types of coal), oil, natural gas and electricity for the two end-user groups household and industry, and for oil for the end-user group transport. 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.

Brubakk et al. (1995) reports simulated elasticities for the industry, 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. Franzen and Sterner (1995) report elasticities for gasoline, which 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 at 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[11] $El^i_p = El^i_{pr}*(1 - k^i) + El^E_{pE}*El^i_{xE}*k^i$, 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.

Some notes should be made about the original elasticities in the three studies used as sources. In some cases, elasticities are reported to be positive. However, these

2. This formula is a slight approximation of the correct, but more complicated, relationship.

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 the E3ME model with the elasticities based on the SEEM model and Franzen and Sterner (1995) (henceforth termed SEEM&FS), the SEEM&FS elasticities for our three sectors are weighted to obtain national elasticities. As our three sectors do not include power generation, which E3ME does, there is a small inconsistency in this comparison. Next, we construct adjustment factors based on the difference between E3ME and SEEM&FS. The adjustment factors are set equal to half the *percentage* difference between E3ME and SEEM&FS, 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 SEEM&FS elasticities for our three sectors (household, industry and transport).

The derived short-run elasticities lie in the interval (–0.08; –0.54). The weighted household (industry) short-run elasticities for coal, oil, natural gas and electricity are –0.19 (–0.19), –0.21 (–0.21), –0.22 (–0.27) and –0.32 (–0.20), respectively. For oil used in transport, the weighted short-run elasticity is –0.19. The weighted short-run elasticity (aggregated over fuels, sectors and countries) is –0.23.

The long-term elasticities lie in the interval (–0.14; –1.84). The weighted household (industry) long-run elasticities for coal, oil, natural gas and electricity are –0.72 (–0.86), –0.89 (–1.03), –0.68 (–1.12) and –0.64 (–0.99), respectively. The weighted long-run elasticity is –0.73 for oil used in transport. The overall weighted long-run elasticity (aggregated over fuels, sectors and countries) is –0.86.

4.1.5 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 (averaging about 0.02), and long-run elasticities mostly between 0.01 and 0.5 (averaging about 0.1). As we do not detect any particular pattern, we choose to employ equal elasticities across fuels and countries. However, we assume that cross-price elasticities in 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 households and industry respectively, and 0.1 and 0.2 as the corresponding long-run cross-price elasticities.[12] In the transport sector, there is only demand for oil and therefore no need for cross-price elasticities.

4.1.6 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, industry and transport (only oil). 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 =

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

$El^i_{xE}*El^E_y$, 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). All derived income elasticities lie in the interval (0.13; 1.86). The weighted income elasticities for coal, oil, natural gas and electricity by sector in the long-run model are shown in Table 4 (All income elasticities are 1 in the short-run model). Finally, the weighted income elasticity aggregated over fuels, sectors and countries is 0.89 in the long-run model.

Table 4 Income elasticities in calibrated model (long run)

	Households	Industry	Transport
Electricity	0.89	0.70	n.a.
Gas	0.71	0.71	n.a.
Coal	0.77	0.66	n.a.
Oil	0.67	0.87	0.98

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

4.1.7 GDP Growth Rates

Historic GDP growth rates for each country and group of countries are based on IMF (2003). The IMF provides annual growth rates for each year in the period 1997–2002. 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 'Roecd' (Rest of OECD) are calculated as the unweighted average of growth rates in Korea, Mexico and Eastern Europe. For the group 'Rannexb', we have used growth rates for 'Eastern European countries' in IMF (2003). For 'Row' (Rest of World) we have used growth rates for 'Developing countries'. Finally, we use the unweighted average of Colombia and Venezuela for the combined Colombia/Venezuela country group. Table 5 presents the historic growth rates and forecasts for selected (groups of) countries in the model.

Future growth rates are partly based on forecasts from IMF (2003), which include annual growth rates for each year in the period 2003–2004 for the same countries as described above. Moreover, Consensus Economics (2003) has forecasts for annual growth rates for selected countries for each of the years 2005–2008, and average growth rates for the period 2009–2013 for the same countries. This information is available for nine of the 16 endogenous European model countries, plus the US, Japan and Canada. For the seven remaining endogenous European countries, we use an unweighted average of the nine former countries.

For Australia, Poland, Russia, Ukraine, China, Indonesia, Algeria, South Africa, Rest-OECD, Rest-Annex B and Rest of World, we generally apply an average of the years 2001–2004 for the years 2005–2008. For Colombia/Venezuela, we use the same rate as the 'Rest of World'. For 2009–2013, we apply either the same rate or a slightly lower rate (e.g., for countries with high current growth rates) for the exogenous countries.

For 2014–2020, we apply annual growth rates of 2.3 per cent for OECD countries, which is approximately the average projected growth rate in the OECD in 2009–2013 (IMF, 2003). For other (groups of) countries, we apply growth rates that lie somewhere between their projected growth rates in 2009–2013 and the OECD growth rate.

Table 5 GDP annual growth rates for selected countries and groups of countries in the model – historic rates and forecasts (per cent)

	Historic rates	Forecasts		
	2001–02	2003–05	2006–10	2011–20
France	1.5	2.0	2.4	2.3
Germany	0.4	1.5	1.9	2.2
Italy	1.6	2.0	2.3	2.3
United Kingdom	1.8	2.2	2.3	2.3
12 endogenous countries*	1.8	2.2	2.3	2.3
China	7.7	7.5	6.8	4.2
Russia	4.7	3.9	4.0	3.4
USA	1.4	3.0	3.1	2.5
Rest of World	4.3	5.2	4.6	4.0

Note: *Unweighted average of growth rates in the countries Austria, Belgium, Denmark, Finland, Greece, Ireland, The Netherlands, Norway, Portugal, Spain, Sweden and Switzerland.

4.1.8 CES Demand Parameters

The calibration of the demand system used is described in detail in Kittelsen (2008). There is a one-to-one relationship between the income elasticities and the endowment parameter for each commodity $\bar{x}_c^D$. This may be used to uniquely calibrate the endowment parameter. There is also a one-to-one correspondence between the value shares and the share parameters a_g^D, but there are a number of artificial exogenous final commodities ('energy-using goods') in the CES tree. Each annual energy good, including the electricity aggregate, is assumed to enter in a nest complementary to an energy-using good (e.g. electric household equipment or fuel-using cars). We have chosen to calibrate the exogenous commodities so that they will have the same value as the energy commodity or nest to which they are complementary, i.e., their value share in the nest to which they belong will be 0.5, and the prices of the complementary goods are all assumed to be one. The remaining quantities and value shares then follow from the data.

For each of the annual energy goods (gas, oil, steam coal, coking coal and lignite) as well as the 12 period electricity goods, the prices and quantities in the CES demand tree are taken from the sources described above. For the total value of consumption, including both energy and non-energy goods, the values are taken from national account statistics (see OECD, 2003). The gross value of production by sector is taken from Eurostat (2003) for the EU countries and from national sources for Japan (Statistics Bureau, 2003) and Norway (Statistics Norway, 2003).

The value of production for the ‘Transport’ sector in LIBEMOD is taken from the Eurostat sector ‘Transport, storage and communication’. The value for the ‘Industry’ sector is calculated as the sum of the production value in the OECD mining, manufacturing and construction sectors excluding the electricity production sector. The value for the household 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 complementarily 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.

Table 6 Calibrated own- and cross-price elasticities for households in the short, medium and long run

	EL	GA	CO	OI
Short run				
EL (electricity)	–0.26	0.01	0.00	0.01
GA (natural gas)	0.03	–0.31	0.00	0.01
CO (coal)	0.03	0.01	–0.22	0.01
OI (oil)	0.03	0.01	0.00	–0.26
Medium run				
EL (electricity)	–0.45	0.02	0.00	0.02
GA (natural gas)	0.09	–0.54	0.00	0.02
CO (coal)	0.08	0.02	–0.61	0.02
OI (oil)	0.07	0.01	0.00	–0.55
Long run				
EL (electricity)	–0.63	0.03	0.00	0.03
GA (natural gas)	0.15	–0.77	0.00	0.03
CO (coal)	0.13	0.02	–1.29	0.03
OI (oil)	0.11	0.02	0.00	–0.85

The substitution parameters in the CES tree are calibrated to minimize the deviation from the target own-price and cross-price demand elasticities, discussed extensively above in subsections 4.1.4-4.1.6 This is not straightforward, because there are more nests (each with its own substitution parameter) than there are endogenous commodities (each with its own-price elasticity), but not enough parameters to match all of the cross-price elasticities. In this sense, the demand system is both over- and underdetermined. In fact, our information on demand elasticities from the literature on own- and cross-price elasticities is for the aggregates of electricity, natural gas, coal and oil, while LIBEMOD has three types of coal and 12 period-specific types of electricity. Because we have no information on the substitution between coal types or electricity periods, we directly specify these parameters as a substitution parameter of 0.5 between the coal types, zero substitution between seasons, and cross-price elasticities of 0.2 between periods in the same season. The remaining substitution parameters are determined by minimizing the mean squared error:

$$\underset{\sigma_g^D}{\text{Min}} \sum_i \sum_j \left(\breve{x}_{ij} - \text{Target}(\breve{x}_{ij}) \right)^2, \qquad (1.95)$$

where g runs over the nests in the CES tree, i,j run over the commodities or aggregates electricity, natural gas, coal and oil (EL, GA, CO, OI in Figure 2.1), and $\breve{x}_{ij}$ are the Cournot elasticities. The minimization is done with the additional restrictions that the substitution parameter σ_k^D must be positive and less than 2.5, because excessive substitution parameters make the solution unstable.

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, because the exact target values are in general inconsistent with economic theory. For some countries and nests, the maximum substitution parameter of 2.5 is binding, resulting in own-price elasticities that deviate slightly from the target values.

Table 7 Calibrated own- and cross-price elasticities for industry in the short, medium and long run

	EL	GA	CO	OI
Short run				
EL (electricity)	–0.18	0.02	0.01	0.04
GA (natural gas)	0.07	–0.28	0.01	0.04
CO (coal)	0.07	0.02	–0.30	0.04
OI (oil)	0.07	0.02	0.01	–0.22
Medium run				
EL (electricity)	–0.63	0.06	0.01	0.09
GA (natural gas)	0.18	–0.76	0.02	0.11
CO (coal)	0.17	0.06	–0.69	0.10
OI (oil)	0.16	0.06	0.01	–0.61
Long run				
EL (electricity)	–1.03	0.09	0.02	0.14
GA (natural gas)	0.29	–1.24	0.03	0.17
CO (coal)	0.27	0.10	–1.54	0.16
OI (oil)	0.26	0.10	0.02	–1.00

In the short-term model, the 'endowment' parameter is set to 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. If the model is run with a medium-term perspective of, e.g., 10 or 15 years, the target elasticities are set midway between the short-term and original long-term target elasticities. Tables 6 and 7 provide the resulting calibrated elasticities for the household and industry sectors. Elasticities deviate somewhat from the target values, e.g., because the effect of a change in the coal price will have little effect on demand for other energy goods if coal consumption is very low at the outset. The transport sector only uses oil, and the price elasticities are –0.24, –0.45 and –0.66 in the short, medium and long run, respectively.

4.1.9 Demand for Energy in Non-Model Countries

Each exogenous country also has some demand for coal and oil to complete the balances. The demand for coal is exogenous in the short run, while in the long run, the modeller has a choice between exogenous demand and a linear demand for each type of tradable coal, calibrated with a demand elasticity of –0.75 (–0.90 for Canada, USA and Japan). The long-run demand elasticities for oil are equal to the long-run demand elasticities for coal, whereas the short-run demand elasticities for oil are one-fourth of the long-run elasticities.

4.2. SUPPLY OF FUELS

4.2.1 Supply of Oil

The base year supply of oil in the model countries is taken from IEA (2002b) measured in Mtoe. We use the 'Indigenous production' of crude oil minus 'Own use' to obtain net production. All short-run elasticities for oil are set to 0.25, whereas all long-run elasticities for oil are set to 1 (see Golombek and Bråten, 1994). The base year supply of oil from non-model countries is taken from *Energy Balances of Non-OECD Countries, 1999–2000* (IEA, 2002e). Furthermore, for the non-model countries, all short-run elasticities are set to 0.25, whereas all long-run elasticities are set to 1 (see Golombek and Bråten, 1994).

4.2.2 Supply of Coal

Coal supply is modelled separately for each of the three coal types (steam coal, coking coal and lignite). Main coal quantities produced, consumed and traded between each pair of trading countries are from IEA (2003), while coal prices are partly from IEA (2002d) and partly from industry sources. The conversions between tons of coal and Mtoe are taken from the import numbers for each country, thus taking into account any implicit quality differences. Minor adjustments have been made to calibrate the balances, including eliminating all trade in lignite by adjusting production in the relevant countries.

The short-run coal supply functions of the major exporting countries (Australia, Canada, China, Colombia and Venezuela, Indonesia, Poland and South Africa) are fitted to detailed export supply potential information from industry sources. The remaining countries have a linear supply function with a calibrated elasticity of 1.0 in the observed point for exogenous countries, and 0.75 for endogenous countries. In the long-run model, all countries have a linear supply function with a base point elasticity of 4.0.

4.2.3 Supply of Oil and Coal in 2010

If extraction starts with cheap fields and then moves on to expensive fields, costs of extraction will increase over time. However, because of technological progress and the possibility of discovering cheaper fields, the costs of extraction may decrease over time.

In order to assess which factors are the greatest, 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 for oil and coal, to calculate the implicitly assumed annual shift in these supply functions. We find that for both oil and coal, the rates lie close to zero; that is, in the long-run model, we assume that the supply functions do not shift over time when we run the model for, e.g., 2010.

4.2.4 Supply of Natural Gas

The base year supply of gas in the model countries is also taken from IEA (2002b) and is measured in Mtoe. In the short-run model, the supply of natural gas from each of the model countries is exogenous (equal to the 2000 extraction levels), whereas in the long-run model, the supply of natural gas from each of the model countries can be either exogenous (equal to the 2000 extraction levels) or endogenous. Regarding the latter, for model countries that are large suppliers of natural gas (the United Kingdom, the Netherlands and Norway), we have convex supply functions (see discussion below), while all other model countries have linear marginal cost functions with long-run elasticities equal to 1 (see Golombek and Bråten, 1994).

Trade between model countries is represented by import numbers taken from *Natural Gas Information, 2002* (IEA 2002f). The only purpose of these numbers is to compare them with the corresponding equilibrium values. Furthermore, net imports of natural gas to the model countries from the non-model countries are import numbers taken from IEA (2002f), supplemented by own calculations. We assume that Russia and Algeria respectively export 76 and 44 Mtoe to Western Europe and that net exports of gas from all other countries to the model countries amount to 9 Mtoe.

We now turn to the long-run supply of natural gas from those model countries that are also large suppliers. The aim is to establish long-run marginal cost functions for the extraction of natural gas; that is, functions including both capital and operating costs. Moreover, short-run marginal 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.

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 the costs of future extraction. However, as we do not have data for future field developments, we assume that the unit costs from the nearest past are fairly good approximations for unit costs in the near 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 understate or overstate the future costs of extraction. However, we do take into account the fact that the total supply potential may typically change over time (see below).

For the United Kingdom, the Netherlands and Norway, we apply the following general functional form for the marginal cost function:

$$c = a_0 + a_1 q + a_2 \ln\left(1 - q / Q\right), \tag{96}$$

where c denotes marginal 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 below). Then Q is adjusted to fit a particular year (2000 or 2010), as total production potential changes over time.

The United Kingdom

There are two data sources used in the calculation of the cost functions for the United Kingdom: WoodMackenzie (1992) (WM) from the early 1990s and World Gas Intelligence (WGI, 1993). Both sources provide information about total costs and total reserves for individual gas fields in the United Kingdom (or combined gas and oil fields). WM includes existing fields with start-ups before 1994–1995 (55 fields), whereas WGI includes fields with start-ups later in the 1990s (38 fields). WM gives much more detailed information about each field, particularly the distribution between capital costs and operating costs. We have assumed that the total costs reported by WGI are equally distributed on capital costs and operating costs. This assumption appears valid based on the data from WM.

The total unit costs for a field are calculated by determining the constant real price that yields 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 lifetime of the field. We assume that the lifetime of the WGI fields is the same as the average life time reported by WM. Several of the fields are combined natural gas and oil fields. In any case, when more than 50 per cent of total reserves are oil, it is assumed that the field is developed for oil extraction, so that only the 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 the 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 stepwise marginal cost function that increases in accumulated production. We then estimate the parameters a_0, a_1, a_2 and Q, which gives us a marginal cost function of the form shown above that mimics the field-based marginal cost function.[13] We assume that the shape of this cost function is representative of the long-term cost structure in UK gas production, but that the total capacity may change over time. Thus, for the year 2000, we increase Q so that the marginal cost function passes actual net production (i.e., 90 Mtoe) around \$110/toe. For the year 2010, total production is expected to be around 25 per cent lower according to WM, and for this year, the cost function is adjusted accordingly. Thus, we obtain the following functions for marginal costs (in USD for the year 2000 price level) in the United Kingdom:

4. In the calibrations, emphasis is put on finding functions that fit well for relatively high rates of capacity utilization; that is, where unit costs are of the same order of magnitude as current prices and producer prices in a liberalized market.

$$c = 22 + 0.6q - 30\ln\left(1 - q/136\right), \left(\text{year 2000}\right),$$
$$c = 22 + 0.6q - 30\ln\left(1 - q/91\right), \left(\text{year 2010}\right). \tag{97}$$

The Netherlands
WM 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 United Kingdom. One exception is the annual production in the huge and very cheap field of 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 most recent years.

Marginal cost functions for total and operating costs are determined as for the United Kingdom. The following function fits well with the marginal cost function for capital and operating costs (in year 2000 USD):

$$c = -16 + 0.9q - 12\ln\left(1 - q/60\right), \left(\text{year 2000 and2010}\right). \tag{98}$$

Norway
WM 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 the United Kingdom. For some of the newer fields, we have used information about breakeven prices and peak production from the OD. We adjust accumulated production so that the rate of capacity utilization is 100 per cent at 50 Mtoe per year in 2000, and 87 Mtoe in 2010 (see WM), reflecting the fact that Norwegian gas production has increased significantly after 2000.

The following function fits well with the marginal cost function for capital and operating costs (in year 2000 USD/toe):

$$c = 49 - 0.2q - 25\ln\left(1 - q/50\right), \left(\text{year 2000}\right),$$
$$c = 49 - 0.2q - 25\ln\left(1 - q/87\right), \left(\text{year 2010}\right). \tag{99}$$

4.2.5 Supply of Biomass

In order to construct a supply function for biomass (used in biomass power) in different countries, we use the following function for marginal costs (see the corresponding functions for natural gas):

$$c = a_0 + a_2\ln\left(1 - q/Q\right), \tag{100}$$

where q denotes supply, Q denotes maximum supply, and a_0 and a_2 are parameters to be determined. Our information is mainly based on Nikolaou et al. (2003).[14] Here we find

5. For Norway, we use Berg et al. (2003).

country-specific information about growth potential until 2010 (compared with actual supply in 2000) for various types of biomass. We assume that all growth potential may be utilized for power production, but that the costs gradually increase and reach infinity when the growth potential is fully realized. That is, we let Q be equal to the sum of the current (2000) supply of biomass to biomass power and the growth potential for 2010. Supply in 2000 is found in *Electricity Information 2002* (IEA, 2002a).

Nikolaou et al. (2003) also give some information about different delivery or shadow costs of different sorts of biomass in the various countries. We take the lowest reported cost figures as the marginal costs of increasing the supply of biomass from the current (2000) level. Moreover, we assume that the weighted average cost reported in Nikolaou et al. (2003) is achieved at the geometric mean of production in 2000 (q) and total supply potential (Q). In this way, we take into account the transitional costs if supply is suddenly and significantly increased.

4.3. ELECTRICITY SUPPLY

4.3.1 Electricity Capacity

The power capacity of each electricity-producing technology is, for each country, from IEA (2002a). This implies that the capacities of the multi-fuel power plants are distributed according to actual fuel use in 2000. The resulting distribution of capacity thus understates the fuel substitution possibilities.

4.3.2 Electricity Efficiency

The actual thermal efficiency for the fossil-fuel-based technologies is based on observed fuel use and production of heat and electricity in 1996.[15] These are reported in IEA (1998a). The mix of heat and electricity production shows a wide dispersion 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,[16] and the 1996 trade-offs are assumed to be representative also for the year 2000. For gas, oil and coal (common trade-off for steam coal and lignite), the results were highly significant, with linear relationships (all variables measured in TWh):

$$\begin{aligned}
&\text{Gas: Electricity} = -0.526\text{Heat} + 0.468\text{Gas}, \left(R^2 = 0.999\right),\\
&\text{Coal: Electricity} = -0.379\text{Heat} + 0.383\text{Coal}, \left(R^2 = 0.998\right),\\
&\text{Oil: Electricity} = -0.211\text{Heat} + 0.415\text{Oil}, \left(R^2 = 0.999\right).
\end{aligned} \tag{101}$$

For each relationship, the first coefficient is interpreted as the change in electricity produced per unit increase in heat production, and the second coefficient is interpretable

6. LIBEMOD 2000 is an updated and extended version of LIBEMOD 96 (see Aune et al., 2001). For example, in LIBEMOD 96, there is an aggregate coal commodity, whereas there are three coal products in LIBEMOD 2000 (see also the next endnote).
7. Greece, Ireland and Portugal are not included in LIBEMOD 96 (but are included in LIBEMOD 2000).

as the gross thermal efficiency had all production been electricity. For waste power (CRW),[17] the results were not significant:

$$\text{CRW}: \text{Electricity} = -0.030\text{Heat} + 0.164\text{CRW}, \ (\text{R2} = 0.097). \tag{102}$$

The lack of significance may partly reflect 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 2000 to its electricity equivalent. Because the CRW coefficients were not significant, the fuel data were pooled to estimate an average trade-off, 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 (2002a) 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 (2002a) 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 of 11.8.

Because of the fact that efficiency differs across plants with the same type of technology, we assume that thermal efficiency is a linear function of capacity utilization.[18] To determine a linear function, one requires two exogenous values. We let one point be the thermal efficiency of the most efficient plant, which is assumed to be equal to the efficiencies reported for new plants in 2000 in IEA (1992). If the country in question reports no efficiencies in IEA (1992), we have used figures from Lissens et al. (1995). Because the technical projected efficiencies do not take account of heat production, some observed 2000 average efficiencies are in fact higher than the estimate for best available new technology in 2000. In these cases we define the maximal efficiency as the observed 2000 average efficiency multiplied by a factor of 1.05. For biomass power, the statistics and projections described do not provide any figures. Instead, we use Bärring et al. (2003) for the basic efficiency and cost assumptions.

A candidate for the second point of the linear function could potentially be the observed efficiency, calculated as the 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. First, the unused parts of all electricity capacities have unobserved efficiency. Assuming that these are mainly vintage plants with lower efficiency, the (true) average efficiency of total capacity will be lower than the observed average efficiency. Second, the different electricity-producing technologies do not have

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8. The technology is termed CRW – Combined Renewables and Wastes – in the statistics, and it comprises solid biomass and animal products, industrial waste, municipal solid waste, and gases derived from biomass and wastes. In the model, this is split into waste power and biomass power.
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).

a constant rate of capacity utilization throughout the year. These rates are not known from primary data. The data only provide information on annual rate of capacity utilization for each technology and the distribution of total production over the 12 time periods.

Instead of using average efficiency directly to determine the second point, we calibrate the capacity utilization for each technology and period by imposing the requirement that, for each country, the outcome should be consistent with cost minimization in electricity production, given our data. The problem is solved by running the electricity production block of the model separately. This cost minimisation procedure also determines the marginal cost of production for each technology in each country and time period, and by implication the difference between the selling price and the marginal cost, and thus forms the basis for the calibration of the market power version of the model, LIBEMOD MP, as explained in subsection 5.4 below. 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.

4.3.3 Operation and Maintenance Costs

Operation and Maintenance (O&M) Costs are taken from the same sources as those used to estimate electricity efficiency. We split this into start-up costs, costs that actually vary with the quantity of electricity produced, maintenance costs that are linked to the capacity that has been used during a year, and costs that are incurred irrespective of use and that therefore can be viewed as long-run maintenance costs. The sources for such a split are very few, and we therefore rely primarily on industry experts.

The Danish Energy Authority et al. (2005) has, however, a few figures for the start-up costs, which we use to calibrate the start-up fuel use and non-fuel start-up costs (for reservoir hydro, pumped storage and wind power (new GSW), the start-up costs are set to zero). For the fossil fuel technologies, these amount in total to approximately 5 per cent of the non-fuel O&M costs. Of the remainder, 10 per cent is assigned to long-run maintenance costs and is therefore related to the investment decision. The rest is then split equally between short-run maintenance and variable costs.

4.3.4 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). Because the model endogenously determines the economically optimal downtime, this restriction should only reflect technical requirements. Unfortunately, we have no clear data on the technically required downtime, as all cost calculations available use some notion of expected downtime for both economic and technical reasons.

Nuclear plants are typically operated for base load in most countries, so we have assumed that the actual usage reflects the technological requirements. Hence, for nuclear, we have calibrated the availability coefficient as the ratio of actual use to capacity (in the base year). 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 the failure of supply, which otherwise may 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 the 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 per cent of the available capacity as reserve capacity. If there is excess capacity that exceeds this level, the price of reserve capacity is zero.

4.3.5 Supply of Reservoir Hydro

Inflow capacity
Our definition of reservoir hydro also includes pondage and run-of-river. 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 (2001). For the other model countries, we used data from IEA (1998a) and IEA (2002a). This provides, for each country, the mean for the years 1993–2000 of net reservoir hydro generation per unit net reservoir hydro generation capacity, which is multiplied by the 2000 net generation capacity. The result is a country-specific estimate of inflow capacity in a hydrological normal year 2000.

Reservoir capacity
The reservoir capacity measures how much water (GWh) 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 the nominal and feasible reservoir capacity, with the difference reflecting uncertainty margins (backup supply).

NORDEL (2001) provides data on nominal reservoir capacities for Norway, Sweden and Finland. The statistics collection also provides data 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 hydropower 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 the nominal reservoir capacities for the remaining countries.

From Nord Pool (2003) we have information on the maximum, minimum and median filling shares for Norway, Sweden and Finland for 1 April and 1 October. For each of these countries, we use the difference between the maximum filling share on 1 October and the minimum filling share on 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 the feasible reservoir capacity. Finally, for the remaining countries, we use the weighted shares of the Nordic countries to estimate feasible reservoir capacities.

4.3.6 New Technologies

For gas power, steam 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.[19] Efficiencies and costs are taken from IEA (1998b).[20] For new pumped storage, there is constant efficiency within each country, but these efficiencies differ across countries because of, 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. New investments in lignite power are assumed to be infeasible.

Turning to reservoir hydroelectricity capacity, we use UNIPEDE (1997) for investment costs in run-of-river, pondage, and reservoir plants. Because of 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 Ministry of Environment, 1992; NOU, 1998). These micro costs are organized in a step function, which is then smoothed with 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 reservoir capacity are assumed to grow proportionately.

Estimates on investment costs in new wind power projects are based on several sources: the Windsim atlas (2004) for Norway, a European wind map from the European Wind Energy Information Network,[21] a report from the Storm Weather Center (2004) on user time for wind power in different European countries, and a report from NVE (2004) on cost estimates for new Norwegian wind power. From these sources, we construct cost functions for the Western European countries.

According to NVE (2004), the total costs of a wind power station in Norway with 3500 user hours are about 0.28 NOK/kWh (investment costs 0.19 NOK/kWh). This is in line with the estimate from the Storm Weather Center (2004) for a station with 3700 user hours at the best wind power locations in Norway. We therefore assume that the cheapest Norwegian wind power stations have a total cost of 0.30 NOK/kWh, of which operating costs amount to 0.075 NOK/kWh. The Windsim atlas for Norway estimates the wind power potential for Norway to be 876 TWh. For a number of reasons, it is only possible to utilize a share of this potential. In the present study, this is assumed to be 10 per cent (for Norway and all other model countries). Furthermore, we assume that the user time of the least efficient power plant is 50 per cent lower than that of the most efficient wind power plant (in Norway and all other model countries). This corresponds

10. In the model, the parameter ‘capital costs’ includes 10 per cent of O&M costs (see the subsection Operation and Maintenance Costs above).
11. Because there is no information on oil power in either IEA (1992) or IEA (1998b), the 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.
12. The map was downloaded from the Internet in 2004, but is no longer available at that web-site.

to a reduction in mean wind speed from 9 m/s to 7 m/s (a doubling of wind speed roughly increases the wind energy by a factor of eight).

From the Norwegian calculations we can derive marginal costs of wind power in a country under alternative assumptions of user hours/wind speed. Combining this information with the wind map from the European Wind Energy Information Network, we estimate marginal costs of wind power in the other model countries.

4.4. TRANSPORTATION OF NATURAL GAS

4.4.1 Natural Gas Transmission Capacities

Our starting point is a model developed by the Foundation for Research in Economics and Business Administration (SNF) (see Grabarczyk et al., 1993).

*Table 8 International transmission capacity for gas in 2000 (in Mtoe); from (row)/to (column)**

	at	be	ch	de	dk	es	fi	fr	uk	gr	ie	it	jp	nl	no	pt	se	ru	ua	us	au	row
at	-	-	-	5.0	-	-	-	-	-	-	-	16.8	-	-	-	-	-	-	-	-	-	-
be	-	-	-	13.5	-	-	-	27.9	7.2	-	-	-	-	23.4	11.3	-	-	-	-	-	-	-
ch	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
de	5.0	13.5	3.0	-	3.0	-	-	18.0	-	-	-	7.7	-	28.8	28.8	-	-	-	-	-	-	1.4
dk	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	2.7	-	-	-	-	-
es	-	-	-	-	-	-	-	2.0	-	-	-	-	-	-	-	4.0	-	-	-	-	-	-
fr	-	-	-	18.0	-	10.0	-	-	-	-	-	0.0	-	-	-	-	-	-	-	-	-	-
uk	-	18.0	-	-	-	-	-	-	-	-	5.0	-	-	-	9.0	-	-	-	-	-	-	-
ie	-	-	-	-	-	-	-	-	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-
it	15.3	-	-	7.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
jp	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.0	20.0	100.0
nl	-	23.4	-	28.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
no	-	11.3	-	28.8	-	-	-	14.4	9.0	-	-	-	-	-	-	-	-	-	-	-	-	-
pt	-	-	-	-	-	4.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
se	-	-	-	-	2.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ru	-	-	-	-	-	-	5.6	-	-	2.7	-	-	-	-	-	-	-	-	220.0	-	-	40.0
ua	41.7	-	-	83.3	-	-	-	-	-	-	-	-	-	-	-	-	-	220.0	-	-	-	-
dz	-	6.3	-	-	-	12.6	-	12.6	-	0.5	-	30.0	-	-	-	1.8	-	-	-	-	-	-
us	-	-	-	-	-	-	-	-	-	-	-	-	5.0	-	-	-	-	-	-	-	-	-
au	-	-	-	-	-	-	-	-	-	-	-	-	20.0	-	-	-	-	-	-	-	-	-
row	-	-	-	-	-	4.1	-	2.1	1.3	-	-	5.0	500.0	-	-	0.3	-	-	-	-	-	-

Note: * For country abbreviations, see Table 1.

Based on input from industry experts, these data have been significantly modified. Table 8 shows international transmission capacities for gas in 2000.

4.4.2 Costs of Natural Gas Transport

The main source is Golombek et al. (1995). However, because of substantial cost reductions in the 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 figures are lower than Golombek et al. (1995). Hence, when pipeline capacities are not fully utilized, the short-run onshore tariff in Western Europe – measured in 2000 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.

4.4.3 Beach Prices for Natural Gas Transport

Beach prices for natural gas – that is, import prices for natural gas – are calculated for each model country as a weighted average of the natural gas import price and the liquified natural gas (LNG) import price. Prices are taken from IEA (2002d), while the quantities are from IEA (2002f). However, for major extractors of natural gas such as the Netherlands and the United Kingdom, beach prices are set equal to their (estimated) marginal costs of extraction in 2000.

Table 9 Sum of domestic costs of transport and costs of distribution for different users of gas (USD/toe)

	Households	Industry	Electricity producers
Austria	206	72	25
Belgium	167	25	25
Denmark	241	41	25
Finland	231	31	25
France	194	67	25
Germany	196	63	25
Greece	129	74	25
Ireland	181	48	25
Italy	18	52	25
Netherlands	116	32	25
Norway	n.a.	n.a.	25
Portugal	249	49	25
Russia	124	25	11
Spain	183	58	25
Sweden	268	68	25
Switzerland	193	59	25
Ukraine	124	25	11
United Kingdom	123	19	25

4.4.4 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, 1998c), the costs of transport in Germany are 55 USD per toe, whereas the costs of distribution are 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 because of the amount of natural gas transported/distributed (data from IEA, 1998c) and the length of the domestic transport/distribution network (data from Figas, 1997). This methodology implies, however, a few extreme results, which we treat by imposing cost ceilings. In addition, for some estimated costs, implied node prices (user price less estimated costs of transport and distribution) are lower than observed beach prices. This should not be possible (in particular when estimated costs should not include any profits above standard remuneration to capital). For these cases, costs are adjusted such that calculated node prices are equal to beach prices. Table 9 shows the sum of domestic costs of transport and costs of distribution for the different users of gas.

4.5. TRANSPORTATION OF COAL

The total cost of transportation for coal is based on port charges in each importing country and shipping costs between each pair of trading countries. Port charges and freight rates per nautical mile are from industry sources. Shipping costs between each pair of countries are then the number of nautical miles times the freight rate. Because the imported quantity of each coal type in each importing country is an Armington (1969) CES aggregate of the quantity bought from each exporting country, trade will only take place between countries that already trade. The substitution parameters in the Armington aggregates are set at 2.0. The share and level parameters of the Armington aggregates are calibrated to equate total imported quantity with the sum of bilateral imports at the base prices.

4.6. TRANSPORTATION OF ELECTRICITY

4.6.1 Electricity Transmission Capacity

We have used UCTE (2001) and NORDEL (2001) as sources for international transmission capacities. UCTE (2001) and www.etso-net.org have data on nominal transmission capacities between the UCTE countries (including most Western European countries except Norway, Sweden, Finland and the United Kingdom) and between UCTE countries and countries sharing borders with UCTE countries. NORDEL (2001) 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 because of loop flow.[22] However, both sources report the transmission capacity for the

13. 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).

line between Denmark and Germany. The estimate of feasible transmission capacity in NORDEL (2001) is slightly below 50 per cent of nominal capacity reported in UCTE (2001). We assume that for all other transmission lines, the feasible capacity is 50 per cent of the nominal capacity. However, for sea cables, we use the nominal capacity as an estimate for the feasible capacity.

4.6.2 Costs of Electricity Transmission

We follow Amundsen and Tjøtta (1997), who 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; NVE, 2000), and 5 per cent of (annualized unit) capital costs for sea cables (see Vognhild, 1992).[23]

4.6.3 Costs of Domestic Transport and Distribution of Electricity

The IEA (2002c) contains, for each country, figures for domestic electricity transport and distribution losses in 2000. In the model, transport losses associated with industrial use are set at 2 per cent (see Amundsen and Tjøtta, 1997). The household sector is assumed to have the residual loss. That is, its loss share is the residual loss quantity divided by total household consumption including loss.

Estimates for the costs for national transport and distribution are also found in Amundsen and Tjøtta (1997). Their model applies 14 NOK/MWh (2.2 USD/MWh) for industry and 88 NOK/MWh (13.5 USD/MWh) for households to all countries included in the study. 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 and Tjøtta (1997) numbers but inflated to 2000 prices and converted into USD. The resulting 2.7 USD/MWh for industry transmission costs is used for all countries, but the household distribution cost varies across countries in proportion to the estimated distribution losses.

4.6.4 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 obtain another estimate, which is based on a 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

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14. Amundsen and Tjøtta (1997) have a tariff of 10 NOK per MWh (about 1.5 USD/MWh). This tariff can be compared with our estimate of the investment cost. If a transmission line of 300 kilometres has a 25-year lifetime and a utilization 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.

Norwegian Ministry of Petroleum and Energy presents cost estimates. The above estimates are in the range of 141 to 555 USD per MW*kilometre. Based on the information from our sources, the estimate is set to 200 USD per MW*kilometre.

For sea cables, we have two sources. Vognild (1992) reports 950 USD dollars per MW*kilometre, whereas the estimate from Statnett (1998) is almost twice as high. We have chosen 1300 dollars per MW*kilometre (measured in 2000 USD) as the estimate of costs of constructing sea cables. For both lines and cables, we assume that any connection costs to the national grid are covered by domestic transmission tariffs.

4.7. ELECTRICITY TRADE

IEA (2002a) 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. All annual trade figures have been disaggregated to periodic trade in each season by assuming proportionality. The only purpose of these constructed numbers is to compare them with the corresponding equilibrium values.

4.8. EMISSIONS

Emission coefficients for CO_2 (ton CO_2 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 2.35, 3.15, 3.99, 3.96 and 4.24 for natural gas, oil, steam coal, coking coal and lignite, respectively.

For emissions of SO_2, we use the RAINS database to estimate the emission coefficients (1000 ton SO_2 per Mtoe) for different fuels, sectors and countries (see Alcamo et al., 1990, 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 10.

Table 10 Average emission coefficients for SO_2 (1000 ton SO_2 per Mtoe) for all model countries

	Household	Industry	Electricity producers
Natural gas	0.0	1.8	0.0
Electricity	0.0	0.0	0.0
Coal	301.9	79.7	253.0
Oil	68.6	29.1	324.9

5. LIBEMOD MP

LIBEMOD MP (Market Power) has the same set of goods, markets, agents and activities as LIBEMOD. Some of the relations in LIBEMOD MP differ from those in LIBEMOD, reflecting market power in production of electricity domestic distribution of energy international trade in electricity and natural gas.

The difference between some of the relations in the two models materializes as mark-up factors being part of the LIBEMOD MP relations, whereas these factors are all set equal to zero in LIBEMOD (competitive markets). Yet, the calibration of the two models is identical, and the mark-up factors are part of the output from the calibration.

Below we document the relations that differ between LIBEMOD and LIBEMOD MP. The calibration of the mark-ups is explained in the last subsection.

5.1. PRODUCTION OF ELECTRICITY

The first-order conditions for profit maximum for all electricity production technologies is modified to include a mark-up $ø_{ml}^{T}$ so that non-profitable technologies are allowed to operate at a loss, while other technologies are similarly penalized. Hence, (24) is changed to

$$P_{mt}^{YE} - c_{ml}^{o} - \mu_{mtl}^{M} - \eta_{ml} - \frac{1}{\psi_t}\left(\phi_{mtl} - \phi_{mul}\right) - \pi_{ml}\nu_{tl}^{m} - ø_{ml}^{T} \leq 0 \perp y_{mtl}^{E} \geq 0$$
$$m \in M^N,\ t = (s,h) \in T, u = (s,h+1) \in T, l \in L^F \tag{103}$$

and similarly for (30), (38) and (44). In this setting, the node price can be identified with a *system price* that represents the marginal cost of electricity production for the electricity sector as a whole in each country.

5.2. INTERNATIONAL TRADE

International gas transmission pipeline owners are allowed to charge a markup $æ_{mn}^{G}$ over transmission costs even when the capacity is not fully utilized. Thus (67) is changed to

$$P_{nj}^{Y} - \frac{P_{mj}^{Y}}{\theta_{mn}^{G}} - c_{mn}^{G} - \mu_{mn}^{G} + \mu_{nm}^{G} + æ_{mn}^{G} \leq 0 \perp z_{mn}^{G} \geq 0,$$
$$j = \text{'gas'},\ (m,n) \in MM^G \text{ or } (n,m) \in MM^G \tag{104}$$

Similarly, electricity transmission line owners are allowed to charge a markup $æ_{mnt}^{E}$ over transmission costs even when the capacity is not fully utilized. Thus (73) is changed to

$$P_{nt}^{YE} - \frac{P_{mt}^{YE}}{\theta_{mn}^{E}} - c_{mn}^{E} - \mu_{mnt}^{E} + \mu_{nmt}^{E} + æ_{mnt}^{E} \leq 0 \perp z_{mnt}^{E} \geq 0, \qquad (105)$$
$$t \in T,\ (m,n) \in MM^{E} \text{ or } (n,m) \in MM^{E}$$

The node or system price is thus also the opportunity costs of electricity for the traders in each country.

5.3. DISTRIBUTION OF ENERGY

The distributors of energy fuels are allowed to charge a markup $æ_{mjq}$ over the node price (in addition to taxes and distribution costs), differentiated by fossil fuel and customer group. Thus (87) is changed to

$$P_{mjq}^{X} = \left[\frac{1}{\theta_{jq}^{m}}(P_{mj}^{Y} + æ_{mjq}) + d_{jq}^{m} + \varepsilon_{jq}^{m} + \omega_{j}^{m}\kappa_{jq}^{m} + \varsigma_{jq}^{m}\chi_{jq}^{m}\right](1+\tau_{jq}^{m}), \qquad (106)$$
$$m \in M^{N},\ j \in J^{F}, q \in Q$$

Similarly, the distributors of electricity are allowed to charge a markup $æ_{mq}^{P}$ over the node or system price (in addition to taxes and distribution costs), differentiated by customer group and time period. Thus (89) is changed to

$$P_{mtq}^{XE} = \left[\frac{1}{\theta_{jq}^{m}}(P_{mt}^{YE} + æ_{mq}^{P}) + d_{jq}^{m} + \varepsilon_{jq}^{m} + \omega_{j}^{m}\kappa_{jq}^{m} + \varsigma_{jq}^{m}\chi_{jq}^{m}\right](1+\tau_{jq}^{m}), \qquad (107)$$
$$j = \text{'electricity'}, m \in M^{N}, t \in T, q \in Q$$

5.4. CALIBRATION OF ELECTRICITY EFFICIENCIES AND MARK-UPS

Unfortunately, the node prices P_{mt}^{YE} are in most countries not observed directly. We only have information on (most) components of the costs of electricity production on the one hand, and the end-user price net of taxes and distribution costs on the other. The relevant supply cost or selling price may in fact also be the node price of another country that one can trade electricity with. Since we do not observe P_{mt}^{YE}, we cannot separately determine $ø_{ml}^{T}$ in (105), and either $æ_{mq}^{P}$ in (107) or $æ_{mnt}^{E}$ in (105). The total profit margin is different for each country, technology and end user or trading partner. The separate specification of a system price allows the decomposition of this margin into two terms.

The main calibration challenge is thus to determine a country-specific 'system price' of electricity, which is needed in order to separate the effects of liberalizing electricity production, liberalizing retail and liberalizing trade. The system price in the model is the opportunity cost of electricity for the suppliers at the central node in each country and is the price that international traders can buy or sell at, as well as the basis on which all mark-ups to end users are calculated. Our approach to calibrating the system price is therefore to calculate the marginal cost of producing one additional unit of electricity within each country. Since we observe in the data that many technologies – at the same point in time – have different marginal costs and produce at less than full capacity, this is calculated as the marginal cost of the most expensive technology, when the total costs of producing the observed amount of electricity in each country is minimised.

We have followed this approach with one modification. In many countries there are technologies with very small market shares: for example, nuclear power in Norway, where capacity is installed purely for research purposes. Similarly, in the data year 2000 there were small-scale experiments with environmental technologies in many countries. These technologies clearly do not represent the system price and have thus been treated as exogenous in the calibration of the model. This is done to avoid the system price being determined by, for example, small-scale experiments.

The use of cost minimisation to determine the system price in each country and period also allows the calibration of another set of unobservable parameters; the distribution of energy efficiencies across power plants of the same technology. As mentioned in subsection 4.3.2 above, different individual power plants have different thermal efficiencies, even if they use the same fuel, in part because of the age distribution of plants. In subsection 3.3.3, we assumed a uniform distribution of plants with a linear schedule of (marginal) efficiencies, see equation (12). To determine a linear relationship, we need two exogenous values. Assuming that the most efficient plant is new in 2000, we know the best and average efficiencies. Even so, it is not straightforward to calculate the linear relationship because: (i) the averages are based only on the plants that actually operated in 2000 and not those too inefficient to be used, and (ii) plants could operate in only some of the 12 periods and not in others.

Unfortunately, we do not have information on the production of each technology in each period, only on the total production of each technology and the total production in each period. In effect, the second parameter of the linear efficiency schedule is underdetermined. We have chosen to identify this parameter by assuming cost-efficient electricity production within each country, subject to the requirement that the period totals and the technology totals add up.

The use of a separate cost minimisation run of the electricity sub-model can thus be used to calibrate simultaneously the a) system price, and by implication all mark-up factors, and b) the distribution of energy efficiencies. For each country *m*, this can be stated as:

$$\text{Min}_{y^E_{mtl},x^{DF}_{ml},x^{DE}_{mtl},K^{PM}_{ml},K^{PS}_{mtl},R^m_s} \sum\nolimits_l C^P_{ml},\ m \in M^N \tag{108}$$

where the costs C^P_{ml} are given by (11), subject to the same restrictions of the short-run optimisation problems such as (23), i.e. (16), (17), (18), (19), (20), where for pumped storage (17) and (20) are replaced by (43) and (42). For reservoir hydro power the additional restrictions (32) and (33) apply.

Additionally, the national minimization problem is subject to the two restrictions on production in each period and country

$$y^{El0}_{mt} = \sum_{l \in L} y^E_{mtl} \perp \tilde{\varpi}^P_{mt}, m \in M^N, t \in T \tag{109}$$

$$y^{Et0}_{ml} = \sum_{t \in T} y^E_{mtl} \perp \tilde{\varpi}^T_{ml}, m \in M^N, l \in L \tag{110}$$

Where the period and technology sums are observed and calibrated so that $\sum_t y^{El0}_{mt} = \sum_l y^{Et0}_{ml} = y^0_{mj}, j = \text{'electricity'}$.

The calibration problem is solved as a Kuhn-Tucker system of complementarity problems. The Lagrangian is formed by (108) and the restrictions above with suitable insertions. This results in new FOCs with respect to period and technology production, reflecting the joint cost minimization instead of the separate profit maximization of (24), (30), (38) and (44):

$$\begin{gathered}-c^o_{ml} - \pi_{ml}\nu^m_{tl} - \mu^M_{mtl} - \eta_{ml} - \frac{1}{\psi_t}\left(\phi_{mtl} - \phi_{mul}\right) + \tilde{\varpi}^P_{mt} + \tilde{\varpi}^T_{ml} \le 0 \perp y^E_{mtl} \ge 0, \\ m \in M^N, t = (s,h) \in T, u = (s,h+1) \in T, l \in L^F\end{gathered} \tag{111}$$

$$\begin{gathered}-c^o_{ml} - \mu^M_{mtl} - \eta_{ml} - \frac{1}{\psi_t}\left(\phi_{mtl} - \phi_{mul}\right) + \tilde{\varpi}^P_{mt} + \tilde{\varpi}^T_{ml} \le 0 \perp y^E_{mtl} \ge 0, \\ m \in M^N, t = (s,h) \in T, u = (s,h+1) \in T, l \in L^U \cup L^H\end{gathered} \tag{112}$$

$$\begin{gathered}-c^o_{ml} - \mu^M_{mtl} - \eta_{ml} - \frac{1}{\psi_t}\left(\phi_{mtl} - \phi_{mul}\right) - \alpha_{msl} + \tilde{\varpi}^P_{mt} + \tilde{\varpi}^T_{ml} \le 0 \perp y^E_{mtl} \ge 0, \\ m \in M^N, t = (s,h) \in T, u = (s,h+1) \in T, l \in L^R\end{gathered} \tag{113}$$

$$\begin{gathered}-c^o_{ml} - \pi^E_{msl}\nu^m_{tl} - \mu^M_{mtl} - \eta_{ml} - \frac{1}{\psi_t}\left(\phi_{mtl} - \phi_{mul}\right) + \tilde{\varpi}^P_{mt} + \tilde{\varpi}^T_{ml} \le 0 \perp y^E_{mtl} \ge 0, \\ m \in M^N, t = (s,h) \in T, u = (s,h+1) \in T, l \in L^P\end{gathered} \tag{114}$$

In addition the original restrictions are also FOCs with respect to their assigned multipliers.

As mentioned, in the calibration we also have data on fuel input x_{ml}^{DF} , but no direct information on ν_{ml}^{1}. Therefore we remove (25) and fix $\pi_{ml} = P_{ml}^{XF}$, and replace (20) with the equality

$$\sum_{t\in T}\left(\overline{\nu}_{tl}^{m} y_{mtl}^{E} + \nu_{ml}^{S} K_{mtl}^{PS}\right) = x_{ml}^{DF}, \forall m \in M^{N}, l \in L^{F} \tag{115}$$

at the same time changing ν_{ml}^{1} from a parameter to a variable to be determined in the model, implicitly by (115).

In addition, we do not attempt to calibrate the pumped storage sector, instead setting $\nu_{ml}^{1} = 0, l = \text{'pumped'}$, and removing (45) and (42).

Solving the modified system of FOCs, we get calibrated values of the efficiency distribution parameter ν_{ml}^{1}. The shadow prices of restrictions (109) and (110) cannot however, be separately determined without a normalisaation. To renormalize, we calculate the calibration system price for each period and country as the marginal cost of the most expensive technology that has a market share, summed over all periods, of at least 10%:

$$P_{mt}^{Y0} = \text{Max}_{l}\left\{\tilde{\varnothing}_{mt}^{P} + \tilde{\varnothing}_{ml}^{T} \,\middle|\, \sum_{u} y_{mul}^{E} \Big/ \sum_{u}\sum_{l} y_{mul}^{E} > 0.1\right\} \tag{116}$$

The calibration mark-up factors in (103) are then just:

$$\varnothing_{ml}^{T} = \tilde{\varnothing}_{mt}^{P} + \tilde{\varnothing}_{ml}^{T} - P_{mt}^{Y0} \tag{117}$$

Calibration of the remaining mark-up factors then follows trivially by solving (104)-(107) for the relevant mark-up.

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