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Coal Transport Demand in Western Europe and Japan: Impacts of Energy Market Liberalisation and Climate Policy

by

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Abstract

Western Europe and Japan are among the main importers of coal. Climate policies following the Kyoto agreement are creating pressure to substitute away from coal and turn to less emission intensive energy sources. At the same time, liberalisations of energy markets in Europe and Japan are likely to cause reduced electricity prices, which will boost the overall demand for electricity. This paper analyses the combined effect of electricity market liberalisation and climate policies on the international coal trade. Using the numerical equilibrium model LIBEMOD, we find that while liberalisation of electricity markets will imply a large increase in aggregate coal transport demand, the negative impact of climate policies may be even larger, in particular if Russia and Ukraine utilise their market power in the market for emission permits. If this market power is exploited, the total effect of liberalisation and climate policy – when including the impact of general economic growth – is a 20% reduction in aggregate coal transport between 2000 and 2010. Further, impacts differ markedly between Western Europe and Japan. A main difference is that liberalisation has a much more positive – and climate policies have a much stronger negative – impact on steam coal demand in Western Europe than in Japan.

Keywords: Coal transport, liberalisation, climate policy, energy markets.

JEL classification: D58, F14, L79

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1. Introduction

The international transport of coal is one of the biggest segments in international shipping, accounting for about 35% of the dry bulk market (Fearnleys, 2001). Since 1978, seaborne coal trade has increased by an average annual rate of 5.9% (IEA, 2001a). But there are clouds on the horizon. Concerns about global warming have led politicians to promote policies that attempt to reduce the consumption of fossil fuels, and in particular the more carbon intensive ones, such as coal. Such policies might be a threat to the future development of the international coal market. The aim of this paper is to analyse how climate policies, together with other key driving forces, will impact on international coal transport demand.

The first international climate agreement – the Kyoto Protocol – has now entered into force. The agreement puts obligations on industrialised countries to limit their emissions of greenhouse gases to 95% of the 1990 emission level, on average. After the USA withdrew from the agreement, the major emission reductions are expected to take place in Western Europe and Japan. These are also some of the main coal importing regions of the world, thus making a drop in world coal trade in the wake of climate policies a highly realistic scenario.

Climate policies are but one of the forces that shape future coal trade. Another potentially important factor is the ongoing liberalisation of energy markets that is taking place in a number of countries. In Western Europe, the past 15 years have seen various initiatives to liberalise the natural gas and electricity markets. The objective of the EU Commission is to transform heavily regulated markets into efficient European markets through regulatory reform (see Thackeray (1999) and IEA (2000)). Japan is also in a process of market liberalisation in the electricity and gas markets. One aim of the liberalisation process is to bring down the electricity prices in Japan, which are currently the highest in the OECD (IEA 2002). Liberalisation of energy markets may have profound consequences for the international coal trade. Enhanced competition is likely to lead to lower prices and higher levels of production and consumption. A substantial share of the increased production may take place in coal fired plants (Aune et al. 2004).

Of course, as long as there is a binding limit on the amount of greenhouse gas emissions, energy market liberalisations will not cause any lasting increase in the use of fossil fuels. Higher consumption levels will have to trigger tougher climate policy measures. In practice, climate policies are likely to be implemented through a system of tradable emission permits in most countries. Such a system places an upper bound on the emission level. If demand for fossil fuels increases (e.g., due to energy market liberalisation), the demand for emission permits will rise, driving up the price of emission permits. This will induce stronger emission reductions in non-energy sectors. For instance, highly emission intensive industry sectors, such as the steel industry, may have to further reduce their emissions. Energy market liberalisation will also affect the relative profitability of the various fossil fuel consuming activities and thus affect the distribution of emission reductions among the different fossil fuels.

To estimate the effect of climate policies on coal transport is a challenging task. First, one needs to depict the effect of climate policies on the demand for coal in different countries. Secondly, for each country one has to determine whether a reduction in coal demand is accommodated by reduced domestic production or whether import demand is reduced. Finally, in order to assess the impact on demand for tonne-miles of transportation, one has to make conjectures on how a reduction in import demand in a given country will translate into reduced volumes for each of the relevant coal exporting regions, which are often located at greatly differing distances from the importing country.

In order to understand how climate policies will affect coal demand, it is essential to understand the structure of the power sector. In the OECD countries, 80 per cent of coal consumption is used for power production (IEA, 2003). Moreover, the possibilities to substitute towards less polluting inputs – either through substitution towards less polluting plants or through within-plant substitution to cleaner fuels – are usually thought to be greater in the power sector than in other sectors of the economy (e.g., Søderholm, 1998). Therefore, the impact of climate policies in the power sector is the key to understanding the total effect of climate policies on coal demand.

Accordingly, our analytical framework puts great emphasis on a detailed description of the power sector. We utilise the numerical equilibrium model LIBEMOD 2000, which models electricity production at the country level in terms of nine different technologies with plant level variations in energy efficiency levels, and takes into account the impact on the profitability of the various technologies of the large variations in electricity demand over the day and between winter and summer. The model combines this fine disaggregation of the power sector with a detailed specification of the international coal trade pattern and the coal extraction costs in source countries, with separate treatment of steam coal, coking coal and lignite.

In existing literature, assessments of the future development in transport demand are rarely based on this kind of detailed specification of the technical and economic relationships in the sectors that generate transport service demand. Similarly, existing literature on the effects of climate policies is often based on rather aggregate representations of the economy.[1] By starting from a disaggregate analysis of the electricity sector, this paper offers better opportunities to understand the forces behind future coal demand, and steam coal demand in particular. The paper builds on the analysis of energy market liberalisation in Aune et al. (2004) but extends their analysis in several directions. Most importantly, this paper adds a detailed description of the world coal markets, including country specific coal extraction cost curves and bilateral trade patterns. In addition, we include several climate policy scenarios, which enable us to analyse the combined effect of energy market liberalisation and climate policy.[2]

Section 2 describes the numerical model, and section 3 presents the scenarios. Results are summarised and explained in section 4. Section 5 concludes.

2. The numerical model

LIBEMOD 2000 combines a detailed formulation of electricity production and trade in Western Europe and Japan with an explicit formulation of costs of coal extraction and the world coal trade. The model also includes the world oil market and a detailed description of the Western European gas market.

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[1] A special issue of *The Energy Journal* edited by Weyant (1999) provides an overview of such modelling and insights, as it comprises 13 analyses of a common set of questions. There are also some industry level studies of the consequences of carbon regulations, e.g., Mathiesen and Mæstad (2004) on the world steel industry, Manne and Mathiesen (1994) on the world aluminum industry and Light (1999) on the world coal industry. Such analyses, like ours, allow for considerably greater detail in the description of the relevant industry, while the rest of the economy is exogenously stipulated.

[2] In addition, there are a number of adjustments in the model set up and data, such as the inclusion of Japan as a country with fully specified energy demand and the update of the base year data from 1996 to 2000.

The model involves six energy goods; electricity, natural gas, oil, steam coal, coking coal and lignite. Electricity is produced, consumed and traded in twelve time periods during the year, whereas fossil fuels are extracted, traded and consumed in annual markets. Electricity and natural gas are traded in two distinct markets; one Western European market and one Japanese (Asian) market. We distinguish between the *core model countries*, in which production, trade and consumption of all goods are endogenous, and *peripheral model countries*, where energy demand is exogenous, but where extraction of fossil fuels may still be endogenous. The core model countries are: Austria, Belgium/Luxembourg, Netherlands, Germany, United Kingdom, Norway, Sweden, Finland, Denmark, France, Spain, Portugal, Greece, Czech Republic, Ireland, Italy and Japan. The peripheral model countries/regions are: Russia, Ukraine, USA, Canada, Algeria, South Africa, China, Indonesia, Columbia/Venezuela, Poland, Australia, Rest Annex B, Rest OECD, and Rest of world.

We begin with a detailed description of the modelling of electricity supply. Next, we present the other elements of the model – supply of fossil fuels, demand for energy, international energy trade, demand and supply from the exogenous countries, and the equilibrium conditions. A full technical description of the model is provided in Aune et al. (2001).[3]

Electricity supply

Production of electricity takes place in each model country through ten different technologies (some of which are not available in all countries): gas power, oil power, hard coal power, lignite power, pumped storage power, reservoir hydro power, nuclear power, waste power, bio power, and GSW (geothermal, solar and wind). Electricity is produced in two seasons (summer and winter). Within each season there are six time periods, reflecting different times of the day. In practice, efficiency in electricity production varies across plants with a given technology in a given country. This is implemented in the model by modelling the supply of electricity from each country/technology *as if* there were a single supplier with increasing marginal costs of production.

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[3] An updated version is due in February 2006 and will be available from the authors upon request.

Consider first the technologies based on fossil fuels; gas power, oil power, hard coal power and lignite power. These technologies are all modelled in the same way. Therefore, we focus on only one of them, henceforth called gas power. For existing production capacity, there are four types of costs involved in gas power production. First, there are costs directly related to the combustion of natural gas. These costs are the product of the user price of natural gas (for the gas power producer) and the amount of natural gas needed to produce a given amount of electricity, which is the inverse of the average energy efficiency coefficient. Secondly, there are costs of other inputs (with exogenous prices). The quantities of these inputs are assumed to vary proportionately with production. Thirdly, there are maintenance costs. These costs are proportional to the maintained power capacity in the gas sector. Fourthly, start-up costs are incurred when the producer increases the production in one period relative to the preceding one (e.g., if production at 7 a.m. is larger than at midnight). Start-up costs are proportional to the start-up power capacity, i.e., the extra capacity needed in order to increase production from one period to the next.

The gas power producers maximise profits by choosing the production level in each period and the maintained power capacity subject to several constraints. First, the maintained power capacity cannot exceed the installed power capacity (which is endogenous in our model). Second, in each period, production of electricity is constrained by the maintained energy capacity, i.e., the maintained power capacity multiplied by the number of hours available for electricity production in the period. Third, due to the fact that all plants need some down-time for technical assistance, total annual production cannot exceed a given share of the total instantaneous maintained energy capacity over the year.

The gas power producer takes into account the fact that due to start-up costs, the costs of producing electricity in a given period will increase if the production level was lower in the preceding period. For instance, the costs of electricity production in the morning hours will increase if the plant did not produce during the night. Start-up costs therefore tend to smooth the production level over the day. But since demand fluctuates over the day, a smoother production level causes increased price variations across different times of the day.

We now turn to *pumped storage power*, where the power producer uses electricity in one period (e.g., winter night) to pump water into a reservoir in order to be able to produce electricity in another (high-price) period (e.g., winter day). The economic structure of this technology is similar to the gas power technology, except that the pumped storage power producer uses electricity rather than fossil fuels as an input.

The *reservoir hydro power* producer has two additional restrictions in his optimisation problem. First, total use of water in each season, or total production of reservoir hydro power, cannot exceed the supply of water (which is equal to the seasonal inflow minus the increase in reservoir filling during the season). Second, the reservoir filling at the end of the season cannot exceed the reservoir capacity.

A *waste power* producer has one additional restriction (relative to the gas power producer): production in each season is constrained by the available waste in that season (measured in energy units), i.e., we assume that there is no waste reservoir.

Nuclear power production is modelled similarly to gas power production, except that start-up capacity is exogenously set to zero. This constraint reflects the fact that due to the time and costs involved in starting up and shutting down nuclear plants, it is never profitable to vary production over the day. Production may thus vary only over the seasons.

The production capacity of *GSW* power (geothermal, solar and wind) varies across periods, but there is no storage possibility. Thus, in the base year, production from renewables is exogenous in each period (equal to observed supply in the data year). In the long run, though, the model allows for new investments to take place in wind power.

We use a long run version of LIBEMOD 2000, in which there is an annual depreciation in the production capacities of old technologies, and where investment in new power technology is possible. Investment takes place whenever marginal revenue from electricity production exceeds long run marginal costs, which includes capital costs in addition to the four short run cost types listed above. Investments in new capacity use newer technology, and have higher efficiencies and lower operating costs than the corresponding old capacity.

Finally, endogenous system levies ensure that there is always reserve power capacity available in each period and country. These levies are the result of a social optimisation problem (not modelled explicitly) and are positive only if the reserve capacity constraint is binding.

Supply of fossil fuels

The model includes coal extraction cost curves at the country level for all major coal exporting countries in the world.[4] There are separate cost curves for steam and coking coal. The optimal level of coal extraction for each coal type is found where marginal extraction costs equal the FOB coal price. In the core model countries, coal extraction (including lignite) is exogenous. The reason is that coal mining in the core model countries typically is heavily subsidised, suggesting that their coal extraction volumes are to a large extent determined by political decisions rather than market forces.

In the core model countries, the supply of natural gas is endogenous. Investment in new gas extraction capacity takes place when marginal revenues exceed long run marginal costs. Russia is an important producer of natural gas for the Western European market, and Ukraine is an important gas transit country. The gas supplies of both Russia and Ukraine are treated as exogenous due to transmission capacity constraints (which are also treated exogenously due to lack of data on investment costs). In Japan, natural gas is imported mainly as LNG. Since LNG can be imported quite flexibly from various source countries, we assume a horizontal supply curve for natural gas in Japan.

The crude oil market is modelled with a global supply of oil, which is price responsive in the standard way.

Energy demand

In each core model country, there are three end-user sectors; households (including services), manufacturing and transport. For each country and type of end-user, demand is derived from a five level, nested CES utility function. Incomes of all end users increase over time by an exogenously defined rate.

At the top level, there is substitution between energy-related goods and other consumption. At the second level, the end users face a trade-off between consumption related to four energy

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[4] Since coal demand in peripheral model countries is exogenous, the coal extraction cost functions translate readily into export cost functions.

goods; electricity-, gas-, oil- and coal-related consumption. Each of these goods is a nest describing complementarity between the actual energy good and consumption goods that use this energy good (e.g., electricity and light bulbs). At the fourth level, coal is further disaggregated into three different coal types (steam, coking and lignite). Also at the fourth level, electricity is disaggregated by season. At the fifth level, electricity demand in each season is disaggregated into electricity demand at each time period of the day.

In addition to demand from end-users, there is intermediate demand for energy goods from electricity producers. Gas power producers demand natural gas, pumped storage producers demand electricity, hard coal power producers demand steam coal, and lignite power producers demand lignite etc.

Trade and transport of energy goods

All energy goods except lignite are traded internationally. Transport of goods from producers to end users takes place at three levels: international transport, national transport and distribution (to households). Each country is represented by a central node.

Oil is transported from the world market to the central node of each country at a given cost. Similarly, steam coal and coking coal are transported from each of the extracting countries to the central nodes of the importing countries at exogenous costs. For each coal type (steam and coking), coal from various suppliers is treated as imperfect substitutes due to quality differences (Armington, 1969). For each coal importing country, a constant elasticity of substitution (CES) formulation is used to allocate import demand for steam and coking coal across coal export regions.

Electricity and gas are transported by international transmission lines (or pipelines) that run between the nodes. Each line is owned by a price taking agent, who transports electricity (or gas) as long as there is a positive price difference between (i) the market price in one country and (ii) the market price in another country plus the costs of transmission (i.e., the costs related to transmission loss plus the transmission tariff). The transport tariff consists of two elements; one exogenous term which is set by the regulator (e.g., in order to ensure a minimum remuneration to capital for owners of transmission lines) and one endogenous term which ensures that the demand for transport does not exceed the transport capacity.

Transmission capacity depreciates over time, but investments in additional transmission capacity take place when the transmission price exceeds long run marginal transmission costs. Finally, transport and distribution of energy from the central node to the end users take place at a given cost (with no capacity constraints).

Equilibrium

In equilibrium, for each core country and for each of the fossil fuels, the total quantities consumed are (less than or) equal to total quantities delivered at the central node (minus a fixed proportion accounting for distribution losses). For each period and each core country, this condition also holds for electricity. For oil, steam coal and hard coal, total world demand is (less than or) equal to total extraction. For lignite, consumption in each country is (less than or) equal to the national production level. There are two natural gas markets, one in Western Europe and one Asian market. In equilibrium, regional gas demand, net of losses, in Western Europe is (less than or) equal to regional gas supply. In Japan, gas demand is determined so that the marginal value of gas consumption equals a given gas supply price in the Asian market.

Data

Much of the data builds on statistics published by international organisations like OECD, UNIPEDE, UCPTE and NORDEL, supplemented by national sources when necessary. Direct price elasticities for coal, oil, natural gas and electricity are drawn from three econometric studies; the SEEM model (Brubakk et al. 1995), the E3ME model (Barker 1998) and Franzen and Sterner (1995). A complete record of the data sources and the principles behind the calibration of model relations can be found in Aune et al. (2001).

3. The scenarios

The base year of the model is 2000. We ask how a new equilibrium in year 2010 compares with the observed levels in 2000. In year 2010 we assume that electricity and gas markets in the core model countries have been fully liberalised. Full liberalisation is interpreted as the implementation of perfect competition, including the elimination of all monopolistic price/cost margins. This radical liberalisation is a rather extreme scenario which probably overstates the true impact of the ongoing liberalisation processes in Western Europe and Japan. Nevertheless, it serves as a natural reference point. Note that all scenarios include the impact of general economic growth over the period.

On top of this liberalisation scenario, we add the implementation of the Kyoto Protocol in all Annex B countries except USA. The Kyoto Protocol is implemented through a system of tradable emission permits. We distinguish two ways of modelling the international permit trade: 1) A competitive permit market with free trade among all Annex B countries[5] (except USA), and 2) a permit market where Russia and Ukraine act as a cartel on the seller side by maximising their rent on permit exports (e.g., Holtsmark (2003), Hagem and Mæstad (2006)).

Since our basis model does not fully describe energy demand in those Annex B countries that are not among the core model countries[6], we need to specify their supply and demand for emission permits explicitly. We have used data from Holtsmark (2003) in order to model the demand for emission permits from Canada, Australia, New Zealand and relevant Eastern European countries, excluding Former Soviet Union (FSU) countries. Their net demand for permits (*d*), measured in million tonnes of CO_2, as a function of the permit price (*p*), measured in USD per tonne CO_2, is given by[7]

$$(1) \qquad d(p) = 150.2 - 6.79p\,.$$

The net supply of permits from Russia and Ukraine (including other FSU countries) is based on the marginal abatement cost curve obtained from simulations with the general equilibrium model DEEP (Kallbekken 2004), which is a variant of the GTAP-EG model (Rutherford and Paltsev 2000). The amount of “hot air” in this model is about 375 MtCO2.[8] The total abatement costs (*c*) for net permit supply (*s*) in excess of 375 MtCO2 are calibrated to[9]

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[5] The Annex B countries are those countries that committed to take on binding emission limits in the Kyoto Protocol.

[6] In particular, gas demand in peripheral model countries is not accounted for in the model.

[7] The model used by Holtsmark (2003) is a linear model. Calculation of permit demand functions can therefore be done straightforwardly by comparing permit prices and permit imports/exports in two different equilibria.

[8] “Hot air” is emission permits that can be sold internationally without any domestic abatement effort and is due to emission standards that are set above the no-abatement emission level in these countries.

[9] Repeated model simulations with the DEEP model provide point estimates of the marginal abatement costs in FSU at varying levels of net permit supply. A marginal abatement cost function is calibrated to fit these point estimates. Integration of the marginal cost function yields the total cost function displayed in (2).

(2) $c(s) = -.0025s^2 + 4.4 \cdot 10^{-5} s^3$

In the scenario with a competitive market for emission permits, the supply of permits from Russia/Ukraine is derived from the condition that marginal abatement costs (obtained from partial differentiation of (2)) equal the international permit price. In the scenario with cartel behaviour, Russia/Ukraine maximise the difference between the total permit export revenue and the corresponding abatement costs.

Since the model does not include non-CO_2 greenhouse gases, we assume that from 2000 to 2010, both CO2 and non-CO2 emissions are reduced by the same percentage amount.

We assume throughout that coal production in the core model countries stays at its 2000 level for political reasons. This is not necessarily a realistic assumption, though. EU countries have signalled that coal production subsidies will be gradually phased out and coal production scaled down accordingly (Kolstad 2004). Sensitivity analysis is however conducted in order to illustrate the significance of this assumption.

Our data sources include estimates of both short run and long run elasticities of energy demand. The scenarios that are analysed in this paper, and which take place within a 10 year time frame, utilise the average of the short and long run elasticities.

4. Results and discussion

This section reports our model predictions of how a liberalisation of electricity and gas markets and the implementation of climate policies may affect the development in coal transport demand in Western Europe and Japan. We also attempt to explain the underlying mechanisms behind our results. The model is solved in GAMS modelling language (Brooke et al. 1998), using the mixed complementarity solver PATH (Ferris and Munson, 1998).

4.1. The effects on transport demand

Our model predicts that if there are no climate policies implemented, but only a liberalisation of electricity and gas markets and general economic growth, the total transport of coal to

Western Europe and Japan will more than double from 2000 to 2010. See Table 1. The annual increase in transport demand will be as high as 8.2%. Interestingly, the development in transport demand differs markedly between Western Europe and Japan. While transport demand into Western Europe is predicted to increase by more than 200% over the ten year period, there is a 17% reduction in transport demand for steam coal into Japan. The explanation is that electricity sectors in these countries respond quite differently to a liberalisation of electricity markets (see below).

Table 1. Transport demand (billion tonne-miles) in 2000. Change in transport demand between 2000 and 2010 shown by indices (Year 2000 = 1).

	Transport demand year 2000	Liberalisation	Liberalisation and climate policy	
			Competitive permit market	Cartel in permit market
Total	**1 480**	**2.20**	**1.26**	**0.80**
Western Europe	892	3.09	1.69	0.96
Japan	588	0.83	0.61	0.54

Climate policy turns out to have a strong negative impact on coal transport demand in both Western Europe and Japan, as transport demand is reduced way below the predicted level without climate policy. In the case of a cartel in the permit market, transport demand in 2010 is predicted to fall to 20% below the 2000 level. In other words, climate policy may turn an 8.2% annual increase in transport demand into a 2.2% annual reduction in demand. However, with a competitive permit market, transport demand will still increase between 2000 and 2010, but at a much lower rate than without climate policies. The large differences between the cartel case and a competitive permit market are explained by the fact that cartel behaviour is predicted to almost double the price of emission permits (see below).

Table 2. Transport demand across coal types (billion tonne-miles) in 2000. Change in transport demand between 2000 and 2010 shown as percentages.

	Transport demand year 2000	Change in year 2010		
		Liberalisation	Liberalisation and climate policy	
			Competitive permit market	Cartel in permit market
Western Europe	**892**	**209**	**69**	**-4**
Steam coal	550	323	129	24
Coking coal	343	27	-26	-47
Japan	**588**	**-17**	**-39**	**-46**
Steam coal	317	-20	-25	-26
Coking coal	271	-12	-57	-70

Table 2 shows that the aggregate figures hide substantial differences in impacts across coal types. In Western Europe, the strong increase in coal transport demand under the liberalisation scenario is driven mainly by a strong increase in steam coal imports. In Japan, on the other hand, the liberalisation scenario has much the same impact on coking coal and steam coal transport demand. Given that energy markets have been radically liberalised, the partial effect of climate policies in both regions is a relatively strong negative impact on coking coal transport. In the steam coal market, though, the impacts differ markedly between regions. While the partial effect of climate policies on steam coal transport to Japan is almost negligible, it causes a huge reduction in steam coal transport to Europe.

4.2. Explanation of results

Changes in coking coal transport are explained mainly by changes in demand for coking coal from large industrial users, such as the steel industry. Since our model is not designed to capture the details of the industrial sectors' coal demands, great care should be taken in the interpretation of these numbers. Our model, with its focus on the electricity sector, is better suited to explain the patterns in steam coal demand. In the following, we will therefore put our emphasis on explaining the effects in the steam coal market. We are particularly interested in explaining why liberalisation of energy markets induces such a large increase in steam coal transport into Western Europe while at the same time steam coal transport into Japan declines. Moreover, we want to understand why climate policies have a strong negative impact on steam coal transport into Europe while the impact on steam coal transport into Japan is negligible.

In principle, the change in steam coal transport demand can be decomposed into changes in the following variables:

- Coal power production levels
- Efficiency in coal power production
- Steam coal consumption in non-electricity sectors
- Domestic steam coal production
- Average distance of steam coal transport

Table 3 summarises some of the key underlying factors that may explain changes in steam coal transport demand. In order to reduce the scope of the discussion, we focus our attention on just one of the climate policy scenarios – the cartel scenario.

Table 3. Changes from 2000 to 2010 in some key underlying variables (%).

	Liberalisation		Liberalisation + climate policy (cartel)	
	Western Europe	Japan	Western Europe	Japan
Steam coal transport demand	**323**	**-20**	**24**	**-26**
Steam coal imports	262	-18	31	-26
Steam coal consumption	144	-17	17	-24
Electricity production	34	104	22	88
Coal power production	135	-15	14	-15

Table 4. Electricity production by technology. Percentage of total.

	Western Europe			Japan		
	Base case	Liberalisation	Liberalisation + climate policy	Base case	Liberalisation	Liberalisation + climate policy
Coal[1]	24.7	43.4	23.2	23.5	9.7	10.6
Gas	17.6	23.1	33.4	22.4	74.1	71.6
Oil	5.7	0.0	0.1	14.7	0.0	0.0
Hydro[2]	19.1	11.7	13.1	9.5	4.2	4.6
Renewables[3]	3.8	5.3	12.0	1.8	1.5	1.8
Nuclear	29.2	16.5	18.2	28.1	10.5	11.4

[1]Hard coal and lignite. [2]Reservoir and pumped storage. [3]Bio power and GSW.

Liberalisation

Consider first the case of liberalisation of energy markets – without climate policies. In general, such liberalisation will cause a decline in electricity prices through the elimination of monopolistic price-cost margins. In Western Europe, end user electricity prices are reduced by 22% (weighted average), to 64 USD/MWh (in 2000 prices). This, together with the general economic growth in the period, explains why electricity production in Western Europe increases by 34%. In Japan, the changes in electricity prices and production are even more pronounced. Japan is known to have some of the highest electricity prices in the OECD. In our base year, electricity prices in Japan are more than twice the price level in Western Europe. Liberalisation radically changes this pattern, as electricity prices in Japan fall to a level even below average prices in Western Europe (56 USD/MWh), a price reduction of almost 70%. This creates a surge in electricity consumption and production in Japan; the model predicts a 104% increase in electricity production between 2000 and 2010 if energy markets are fully liberalised. There is reason to believe, however, that the real impact will be smaller. In our model, Japan is able to expand electricity production through a substantial increase in gas power production, where gas is purchased at a constant (albeit high) price at the world market. However, constraints in the capacity to handle LNG will most likely limit the expansion of gas imports, thus leading to a smaller reduction in electricity prices and a smaller expansion of electricity production than the model predicts. This may also imply that the model's prediction of steam coal import demand in Japan is underestimated.

As for the impact on the coal trade pattern, changes in the *composition* of electricity production turn out to be far more important than the overall production level, see Table 4. At this point, the difference between Japan and Western Europe is quite striking. In Western Europe, liberalisation causes an increase in the share of coal power in total electricity production from 25% to 43%. In Japan, the pattern is the opposite; the share of coal power declines from 24% to 10%. Practically all investments that are needed in order to accommodate higher electricity demand in Japan take place in gas power production, leading to an increase in the share of gas power from 23% to 74%. In Europe, on the other hand, natural gas is not as profitable relative to coal power, and most of the capacity expansion takes place in the coal power sector. Note that all other power producing sectors experience a decline in their share of electricity production when markets are liberalised (except a slight increase in the renewables sector in Europe). Note also that a significant share of the expansion in fossil fuel power production takes place because the model assumes that there are no replacement investments in the nuclear power sector.

Consider next how the changes in coal power production translate into changes in coal transport demand. In Western Europe, the increase in steam coal consumption is even higher than the increase in coal power production. This occurs despite the fact that consumption of steam coal does not change much in non-electricity sectors and is due to higher capacity utilisation rates in less efficient plants as coal power production expands. The 144% increase in steam coal consumption corresponds to a 262% increase in imports. This figure is obviously sensitive to our assumptions about domestic steam coal production in Western Europe. In our model scenarios, coal production in Western Europe, which is under heavy political control, is unchanged. It is not unrealistic to assume that these production levels will be reduced, despite higher demand for coal, due to the ongoing process of dismantling coal-subsidies in Europe. A 10% reduction in domestic coal production in Western Europe will increase import demand (for a given import price) by a further 13%. This implies that the projected import figures for Western Europe are quite uncertain and sensitive to our assumptions about future coal subsidies and coal production in Western Europe.

In Western Europe, the 262% projected increase in steam coal imports will result in a 323% rise in steam coal transport demand. The difference reflects the fact that distant steam coal sources will come to play a relatively more important role in Western European imports when markets are liberalised.

The analysis of Japan's steam coal import demand is much simpler. A somewhat higher price of coal in the world market (due to increased demand for coal) reduces coal consumption in non-electricity sectors, leading to a 17% overall reduction in steam coal consumption. Due to negligible amounts of domestic coal production, the Japanese steam coal imports follow the consumption level quite closely. Moreover, as the coal trade pattern does not change much, the fall in steam coal transport demand does not deviate much from the change in total steam coal consumption.

Liberalisation and climate policy

We have seen that climate policy has a strong negative impact on projected coal transport demand. The impact is particularly strong in the case of cartel behaviour, because the price of emission permits – and thus the consumer price of coal – is then particularly high. The impact of climate policy on fuel prices in power production is displayed in Table 5. The equilibrium price of emission permits in our model is 21.8 USD/tCO_2 with cartel behaviour.[10] This permit price leads to an almost 100% increase in steam coal prices for power producers (relative to the case of pure liberalisation) and also to a significant rise in the prices of oil and gas.[11] With a competitive permit market the increase in fuel prices would be lower as the price of emission permits in that case would be only 12.4 USD/tCO_2. The lower permit price is caused by an increase in the exports of permits from Russia/Ukraine from 720 to 1170 million tonne CO_2 equivalents.

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[10] This estimate corresponds fairly well to recent prices in the EU market for CO_2 emission permits.

[11] Note that the relative increase in the oil price is smaller than the increase in the gas price, despite the fact that the emission rate per energy unit is lower for gas. The reason is that oil is more heavily taxed than gas and therefore has a significantly higher user price at the outset.

Table 5. Impact of climate policies (cartel) on fossil fuel prices in power production (%). (Relative to the liberalisation case)

	Coal	**Gas**	**Oil**
Western Europe	99	45	31
Japan	84	29	23

Higher fuel prices lead to higher electricity prices and a reduction in aggregate electricity consumption and production in both regions, but, again, the impact on coal power production turns out to differ markedly. In Western Europe, where climate policy reduces the growth in electricity production from 34% (pure liberalisation) to 22% (liberalisation and climate policy), the growth in coal power production is reduced from 135% to 14%. Thus, in addition to the scale effect, there is substantial substitution away from coal power.

Despite the strong negative impact of climate policies on steam coal demand in Western Europe, the net effect is still an increase in steam coal consumption by 17% relative to year 2000. With no change in domestic coal production, this translates into a 31% increase in steam coal imports. But in contrast to the case with only liberalisation, the increase in coal transport demand (24%) is now smaller than the increase in coal imports. This suggests that with small increases in steam coal imports, Western Europe will rely more heavily on nearby coal sources, whereas the more distant sources will play a more important role with a larger surge in coal imports. The average transport distance of imported coal in Western Europe is 4500 nautical miles in the base year. With pure liberalisation, the average distance in 2010 is predicted at 5200 nautical miles, while adding climate policy (cartel) implies a reduction to 4200 nautical miles.

In contrast to Western Europe, coal power production in Japan is completely unaffected by climate policies, despite the fact that the growth in electricity production is significantly down here as well. The explanation is that coal power producers in Japan are producing at their capacity limit in the liberalisation case (but the margin is too low to induce investment in new capacity). Climate policy reduces the profitability in Japanese coal power, but the margin will still be high enough to maintain production at the capacity limit.

Even though coal power production is unaffected in Japan, climate policy still induces a further reduction in Japanese steam coal imports, down from –18% to –26%. Japan’s steam coal transport demand is down by a similar magnitude. The explanation is reduced steam coal demand in non-electricity sectors as coal prices increase.

4.3. World coal transport

We close with a few comments on the impacts on aggregate world coal transport. Our model is not well suited to analyse the impacts at the global level, because neither energy demand nor transport demand in peripheral model countries is (fully) endogenised. Thus, while transport demand in peripheral countries is constant in our model, we would expect price mechanisms to produce opposite effects relative to the core model countries, thus leading to a dampening effect on the impacts of world transport demand (unless these countries implement similar policies). This would surely happen in the case of energy market liberalisation, where the large increase in coal demand in Western Europe and Japan would increase both coal prices and freight rates and cause a reduction in coal imports in the rest of the world. The estimated increase in global coal transport of 72% should therefore be adjusted downwards.

However, when climate policies are implemented in addition to liberalisation, the estimated reduction in global coal demand of 12% is more likely to be a reliable estimate. The reason is that coal prices are not much affected in this case (relative to the base year), because higher coal demand in Western Europe is counteracted by a similar reduction in Japanese coal demand. Thus, we may conclude that climate policies are likely to have a strong negative impact on global coal transport.

Table 6. Total coal transport demand (billion tonne-miles) in 2000. Change in transport demand between 2000 and 2010 shown by percentages.

	Transport demand year 2000	Change in year 2010	
		Liberalisation	Liberalisation + climate policy (cartel)
Western Europe + Japan	1480	120	-20
Rest of world	988	0	0
Total	**2467**	**72**	**-12**

5. Concluding remarks

The main message of this paper is that both energy market liberalisation and climate policies in Western Europe and Japan are likely to have profound consequences on coal transport demand in these regions, as well as on the world coal transport markets. Using a numerical equilibrium model with a detailed description of electricity and gas markets we find that with a radical liberalisation of energy markets on top of the general economic growth, aggregate coal transport demand in Western Europe and Japan in 2010 will exceed 2000 levels by 120%. However, by adding climate policies, the increase in coal transport demand will be reduced to 34% in the case of competitive international permit trade, while there will be a decline in coal transport demand by 20% relative to 2000 if Russia/Ukraine utilise their monopoly power in the international permit market to raise the price of emission permits. The model also predicts that the impacts of the policy reforms on coal power production differ markedly between Western Europe and Japan, with Japanese coal power production responding far less positively to market liberalisation and far less negatively to climate policies than coal power production in Western Europe.

Several caveats should be kept in mind in the interpretation of the results. First, it is not realistic that full liberalisation, with complete elimination of all monopolistic rent, will be observed in this period. Hence, the fall in electricity prices and the resulting boost in demand in the liberalisation case are unrealistically large.

Second, the modelling of the Asian gas market, with a horizontal supply curve of gas, probably underestimates the cost of the large expansions of Japan’s gas power production. With the huge increase in gas power production predicted by the model, some kinds of capacity constraints are likely to set in. This will probably lead to a more positive development in Japan’s coal power production in the liberalisation case, but it may also imply a more negative impact of climate policies, more in line with the predictions for Western Europe.

Finally, the climate policy scenarios do not account for the possibility of using the Clean Development Mechanism (CDM) to increase the aggregate supply of emission permits through cheap abatement efforts in developing countries. By including CDM, the price of emission permits would be lower in all scenarios, resulting in less negative impacts on the coal transport demand.

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