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Cross-Country Electricity Trade, Renewable Energy and European Transmission Infrastructure Policy

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Cross-Country Electricity Trade, Renewable Energy and European Transmission Infrastructure Policy

By Jan Abrell and Sebastian Rausch*

This paper develops a multi-country multi-sector general equilibrium model, integrating high-frequency electricity dispatch and trade decisions, to study the effects of electricity transmission infrastructure (TI) expansion and renewable energy (RE) penetration in Europe for gains from trade and carbon dioxide emissions in the power sector. TI can benefit or degrade environmental outcomes, depending on RE penetration: it complements emissions abatement by mitigating dispatch problems associated with volatile and spatially dispersed RE but also promotes higher average generation from low-cost coal if RE production is too low. Against the backdrop of European decarbonization and planned TI expansion, we find that emissions increase for current and targeted year-2020 levels of RE production and decrease for year-2030 targets. Enhanced TI yields sizeable gains from trade that depend positively on RE penetration, without creating large adverse impacts on regional equity. (JEL F18, Q28, Q43, Q48, C68)

For several reasons, promoting cross-country electricity trade and transmission infrastructure is a major European policy issue. Electricity produced from fossil fuels generates environmental externalities.[1] Achieving sizeable emission cuts as envisaged under European Union's (EU) climate policy will require that large amounts of electricity are produced from intermittent renewable energy (RE) sources such as wind and solar. As these RE sources are not evenly distributed across Europe, with wind resources predominantly located on the periphery of the continent and often far away from demand centers, it seems unlikely that climate policy targets can be achieved without complementary cross-country transmission infrastructure policy (TIP). By sharing more efficiently "back-up" production capacities across countries, electricity trade can moreover help to reduce the costs of integrating large amounts of intermittent RE sources into today's economies and to increase security of energy supply. In addition, cross-country electricity trade increases

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[1] In 2014, approximately 40 percent of European carbon dioxide (CO_2) emissions—the principal anthropogenically sourced "greenhouse gas" contributing to global climate change—derived from electricity use (International Energy Agency, 2015).

competition with benefits for consumers. While these arguments provide a rationale for public policy oriented toward promoting cross-country electricity trade, surprisingly little is known about the interactions between transmission infrastructure, renewable energy, and environmental outcomes.

This paper develops a multi-country multi-sector general equilibrium framework, integrating high-frequency electricity dispatch and trade decisions, to study the effects of transmission infrastructure expansion and renewable energy penetration in Europe for the regional distribution of gains from trade and CO_2 emissions from electricity production. Combining a general equilibrium model with a bottom-up electricity dispatch model permits a consistent welfare analysis while being able to approximate determinants for cross-country electricity trade and ensuing gains (or losses) from trade, also taking into account the use of electricity in the broader economic system. Besides cross-country differences in technology and production costs, hourly electricity trade is driven by imperfectly correlated demand and supply across countries while being constrained by cross-border transmission infrastructure. The trade effects are included in a fully specified numerical general equilibrium model for Europe that is calibrated using empirical country-level data on hourly electricity demand, installed generation capacities, hourly RE (wind and solar) production, and social accounting matrix data on production, consumption, and bi-lateral trade (in non-electricity commodities).

Our analysis highlights the central role played by infrastructure for environmental outcomes. On the one hand, electricity grid infrastructure might complement emissions abatement by mitigating dispatch problems associated with renewables. On the other hand, enhanced transmission infrastructure might promote higher average generation using low-cost base-load fossil (e.g., coal) with relatively higher emissions intensity—therefore degrading, rather than benefitting, environmental outcomes. How transmission infrastructure impacts emissions may further depend on contemporaneous renewable energy policy affecting the amount of low-cost renewables which can be more effectively distributed in an enhanced electricity grid.

While this fundamental trade-off arguably arises in most interconnected energy systems that are sufficiently large and geographically dispersed, we examine this issue in the context of European decarbonization and electricity transmission infrastructure policy. Recently, analysts and policymakers have called for new and more comprehensive policies to increase cross-border transmission capacities for electricity in Europe. The Ten Year Network Development Plan (TYNDP) is the main instrument under current EU regulation aimed at extending cross-border TI. The TYNDP, administered and implemented by the European Network of Transmission System Operators for Electricity (ENTSO-E), identifies transmission expansion plans deemed necessary to ensure that the future TI facilitates achieving EU energy and climate policy goals.(ENTSO-E, 2014).[2]

[2]The TYNDP includes so-called "Projects of Common Interest", that is, electricity projects with significant benefits for at least two member states. The majority of planned TI projects are expected to be commissioned by 2030, and the ENTSO-E (2014) expects that by promoting international electricity trade and by enabling the integration of large amount of RE sources the planned TIP will bring about significant economic and environmental gains in terms of reduced cost of electricity for consumers, increased profits for electricity firms, and a reduction of electric-sector CO_2 emissions.

Our analysis shows that, at low levels of renewables in line with with current and year-2020 EU targets, infrastructure enhancement induces a substitution toward low-cost coal-fired electricity yielding higher emissions (at the European level). At higher levels of renewables, in line with 2030 EU targets, infrastructure enhancement lowers emissions, because spatial variations in RE production can be better dispatched to meet demand. An important implication of our analysis is that "environmentally friendly" but spatially uncoordinated RE policies in a highly developed grid bear the risk of unintended consequences in the form of degraded environmental outcomes and emissions leakage. While the problem is only transient and will eventually disappear once the RE penetration is sufficiently large, our findings point to the need to consider a coordinated emissions and infrastructure policy.

Another important finding is that enhanced transmission infrastructure has the potential to bring about sizeable gains from trade through increased economic efficiency. Depending on the level of RE production, the TYNDP would yield aggregate (Europe-wide) gains between 1.6 to 2.6 billion 2011$ per year (corresponding to an 0.02-0.03% increase in annual welfare which is non-negligible given that the value share of electricity in total output is only about 4%). Infrastructure enhancements beyond the TYNDP could deliver gains between 5.8 and 8.7 billion 2011$ per year, corresponding to an 0.06-0.09% increase in annual welfare. Notably, we find that welfare gains from TI enhancements significantly increase with the level of RE production as low-cost renewables can be more efficiently distributed in an enhanced electricity grid. Welfare gains from the TYNDP are about twice as large for year-2030 RE levels, as targeted by EU climate policy as what would obtain for current (year-2012) levels.

Notably, we do not find strong adverse equity impacts from enhanced TI in terms of the regional distribution of gains from electricity trade. TI enhancement makes the large majority of countries better off. Some countries with initially low electricity prices or "wheeling" (electricity transit) countries experience slight welfare losses from enhanced European cross-border TI. Losses arise primarily due to losses in non-electricity sectors of the economy, underscoring the importance of an economy-wide perspective beyond just electricity. Lastly, we show that enhanced TI profoundly changes the pattern of regional CO_2 emissions.

Our paper is related to the literature in several ways. Assessing the environmental and economic impacts of enhanced TI is intimately linked to understanding what drives cross-country electricity trade. Electricity is a homogeneous good that can only be stored at high cost, and output may be produced by a wide range of different technologies. Demand and supply conditions vary considerably over both short time scales of a day and longer time scales of a season or year. Two-way trade in a homogeneous good (electricity) in our model is a result of aggregation over time similar to Antweiler (2014). von der Fehr and Sandsbraten (1997) present a stylized theoretical partial equilibrium model to investigate the gains from liberalizing electricity trade in the Nordic countries. Our set-up differs from Antweiler (2014) and von der Fehr and Sandsbraten (1997) in that it integrates two-way trade in a general equilibrium framework.

It is important to understand both the determinants of transport costs and the magnitude of the barriers to trade that they create. Previous trade literature has shown (Gramlich, 1994; Bougheasa, Demetriades and Morgenroth, 1999; Limao and Venables, 2001) that infrastructure is an important determinant of trade. In our model, equilibrium transport costs for electricity depend inversely on the utilization of available transmission capacity, the shadow costs of TI. To the best of our knowledge, we are the first to study the role of infrastructure for cross-country electricity trade in an general equilibrium context.

A few prior studies have assessed the gains from electricity TI policy and increased cross-country flows. The common feature of these studies is their reliance on partial equilibrium welfare measures focusing on either supply cost reductions (Rogers and Rowse, 1989; Newbery et al., 2013), impacts in terms of cross-country price differentials (Bessembinder and Lemmon, 2006; Newbery et al., 2013; Bahar and Sauvage, 2012), or consumer and producer surplus (von der Fehr and Sandsbraten, 1997). In contrast, economic decisions in our model stem from a consistent profit and utility maximization framework which enables measuring efficiency and distributional impacts of cross-country electricity trade in terms of theoretically sound welfare indexes. In addition, the economy-wide general equilibrium perspective captures the interactions between the electricity sector and the broader economy.

Lastly, our analysis is also germane to the literature on integrating "top-down" economy and "bottom-up" energy models for energy and climate policy assessment—see Hourcade et al. (2006) for an overview, and Boehringer (1998), Boehringer and Rutherford (2008), and Rausch and Mowers (2014) for examples of applications related to electricity. We make use of recent advances in computational techniques (Boehringer and Rutherford, 2009) to ensure that electric-sector optimization is consistent with the comparative-static general equilibrium model including endogenously determined electricity demand, fuel prices, and goods and factor prices. Importantly, employing a structurally explicit model for fuel switching in the electricity sector overcomes difficulties inherent in a "top-down" approach based on highly aggregated production functions and poorly estimated substitution parameters that determine the fuel mix response to policy changes.

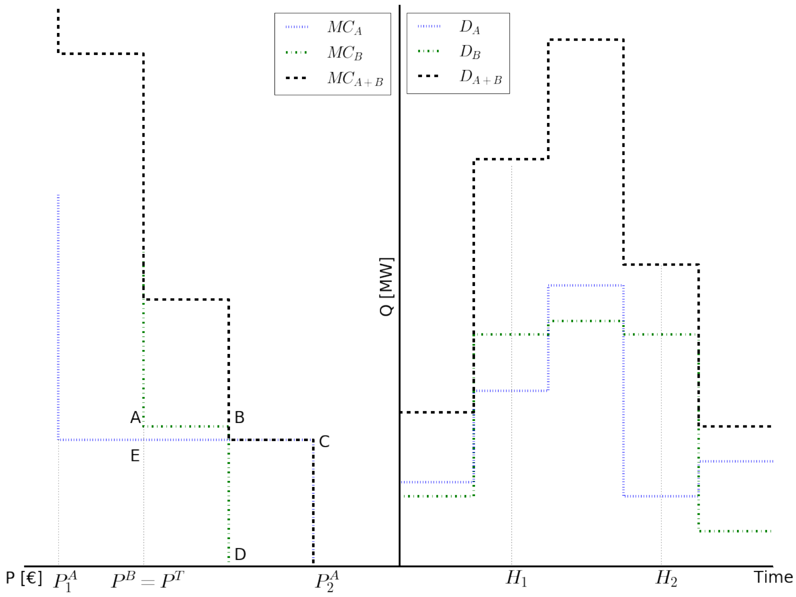
The remainder of the paper is organized as follows. Section I introduces the conceptual framework for our applied policy analysis. Section II provides an empirical background on the key drivers for cross-border electricity trade in Europe. We introduce the equilibrium model, describe the underlying data, and our computational strategy in Section III. Simulation results are summarized in Section IV. We conclude with a summary of results and directions for future research in Section V.

I. Conceptual Framework

A. *Electricity Production, Demand, and Cross-country Trade*

To build intuition for the basic economic forces at work in our empirical setting, we first present a simple, stylized model for electricity production, demand, and trade. Figure 1 shows two countries A and B characterized by marginal cost supply schedules MC_A and MC_B (left quadrant) and demand schedules D_A and D_B over a given time period (right quadrant). Differences in the step-wise supply curves reflect that both countries

Figure 1. Cross-border electricity trade, marginal production costs, installed capacities, and asynchronous demand



differ with respect to the technology mix of installed capacities: the low-cost technology is relatively cheaper in country A whereas the high-cost technology is more costly in country B. Countries also differ with regard to the size of electricity demand at a given point in time implying asynchronous demand schedules. Dashed lines denote the aggregated marginal cost supply function (MC_{A+B}) and aggregated demand over time (D_{A+B}), respectively.

The equilibrium (marginal cost) prices of electricity for A and B at a given point in time, for example, hours H_1 and H_2, can be found by mapping demand to the respective marginal cost schedule (i.e., by drawing a horizontal line from D_A to MC_A).

To meet demand in hour H_1 under autarky—for instance, due to the lack of cross-border transmission infrastructure—country A and B use their high-cost technology yielding respective equilibrium prices of P_1^A and P^B. If international trade becomes possible, the equilibrium price for H_1 in both countries is P^T consistent with MC_{A+B} and D_{A+B}. In this case, country B in H_1 becomes an exporter of electricity while country A now imports electricity at a price $P^T < P_1^A$.

How does an increased share of RE influence cross-border electricity trade? Suppose country A adds a positive amount of electricity production from RE with zero marginal cost while country B leaves its production capacities unchanged. In Figure 1 this could be depicted by a parallel shift of the curve MC_A to the left, or, equivalently, by lowering its demand to represent residual load, i.e. load net of RE production. When we choose the latter representation, this is exactly what is borne out by comparing H_2 to H_1 with demand in country A falling (and leaving demand in B unchanged). As a result, the autarky price in A falls from P_1^A to P_2^A. The trade pattern reverses with A (B) becoming an electricity exporter (importer). Moreover, it is easy to see that the correlation of time profiles between RE generation and electricity demand matters for determining trade.

Figure 1 is useful to shed light on the fundamental economic factors that determine electricity trade and that bring about variations in the sign and magnitude of cross-border trade. Intuitively, electricity trade thus depends on: (i) marginal cost curves, (ii) the position of these curves relative to the aggregate marginal cost curve which is determined by cumulative capacities, (iii) the relation between aggregate marginal cost and aggregate demand where (iv) aggregate demand depends on the (a)synchronicity of country-level demands.

B. *Gains from Trade and Applying the Framework*

Determining the welfare impact due to international electricity trade requires evaluating for each market at time t both the change in producer and consumer surplus; such an assessment is straightforward comparing the areas under the supply and demand curves in Figure 1.[3]

While Figure 1 is a useful first step to understand the economic determinants of cross-border electricity trade and the welfare implications, several of the simplifying assumptions that facilitate the graphical exposition (and in fact the underlying partial equilibrium analysis) have to be relaxed in order to arrive at a realistic assessment. We highlight four of these assumptions here. First, both industrial and private consumers react to price changes. Intuitively, welfare impacts for consumers can look quite different if demand is price-elastic.

Second, demand for electricity is not only a function of electricity price but also depends on consumers' real incomes as well as prices for other energy and non-energy commodities. Not taking into account the effects of electricity firms' profit and changes in the relative price of electricity on demand may lead to a misspecification of the electricity demand response and hence false welfare implications.

Third, in present day real-world economies electricity represents an essential input for the vast majority of production and consumption activities. Thus, to the extent that cross-border electricity trade impacts electricity prices, production costs of other sectors are altered. In particular, this is true as the substitutability between electricity and other forms of energy as well as non-energy inputs (capital, materials etc.) is limited. Changing the cost of electricity impacts both output prices and firms' profits of non-electricity industries, and alters demand and supply for intermediate inputs used in the production of electricity. If these feedback effects from the broader economic system are not considered, the welfare assessment of cross-border electricity trade can look quite different across otherwise similar

[3] As an example, compare equilibria when meeting demand H_2 under autarky or when international trade is allowed. Under autarky, producer surpluses (PS) in both sum to the area $ABDP^B$. With international trade, the total PS is given by the areas $ABDP^T + ECP_2^A P^T$ indicating a gain equal to $ECP_2^A P^T > 0$ which results from increased sub-marginal rents on the low-cost RE technology in country A due to both an increase in the utilization of the low-cost technology and the creation of rents for units that would have already been sold under autarky (since $P^T > P_2^A$). In this example, cross-border electricity trade (weakly) increases the PS for each country. Changes in firms' profits have to be traded off against changes in consumer surplus (CS). Electricity consumers in country B are indifferent between autarky and international free trade since $P^B = P^T$ whereas the CS in country A is reduced as $P_2^A < P^T$.

Table 1. Installed production capacities (availability adjusted), yearly-averaged hourly domestic demand, and average marginal technologies[a]

	Installed production capacity by technology					Average hourly demand	Average marginal technology	Average excess capacity[b] [%]	Demand factor[c] [%]
	Hydro	Nuclear	Coal	Gas CC	Gas Turbine				
Austria	4.9	0.0	1.2	4.3	1.0	7.9	Gas CC	64.1	89.6
Belgium	0.2	4.4	0.8	6.4	0.7	9.7	Gas CC	52.3	96.8
Czech	0.4	3.3	8.0	0.9	0.0	7.2	Coal	75.8	86.1
Denmark	0.0	0.0	3.1	1.8	1.5	3.9	Gas CC	107.9	77.0
Finland	1.9	2.5	2.6	2.7	0.7	9.7	Coal	60.0	93.2
France	7.3	46.2	6.4	8.9	1.4	55.9	Coal	40.5	130.6
Germany	2.7	10.8	44.1	19.4	7.6	61.6	Gas CC	50.7	92.5
Ireland	0.1	0.0	0.8	3.8	0.8	3.0	Gas CC	136.6	66.1
Italy	4.9	0.0	10.3	48.2	5.4	37.5	Gas CC	128.0	64.3
Netherlands	0.0	0.4	3.6	15.7	1.7	12.99	Gas CC	70.7	84.8
Norway	16.3	0.0	0.0	1.4	0.0	14.6	Hydro	22.6	131.0
Poland	0.3	0.0	27.4	0.9	0.1	16.5	Coal	78.9	80.0
Portugal	0.7	0.0	1.6	4.6	0.2	5.6	Coal	77.7	86.3
Spain	2.7	6.7	9.5	30.6	0.4	30.5	Gas CC	91.7	77.8
Sweden	8.9	7.0	0.3	1.0	0.3	16.2	Nuclear	46.1	111.2
Switzerland	4.5	2.8	0.0	0.4	0.0	7.39	Nuclear	11.4	138.8
UK	0.6	7.6	22.5	36.2	2.4	36.2	Gas CC	113.7	74.2
Europe[d]	56.3	91.6	142.2	187.0	23.9	336.3	Gas CC	71.0	88.2

Notes: [a]All numbers are in GW unless otherwise noted. [b]Relative to annual average demand. [c] Defined as the ratio between maximum peak and possible load. Storage capacity is excluded from calculations. [d]Aggregate of the 18 countries listed above.

models of electricity production, consumption, and trade.

Fourth, interactions with the broader economic system trigger changes in producer and consumer surpluses in non-electricity markets that have to be taken into account for a comprehensive welfare assessment.

II. Empirical Determinants of Cross-Country Electricity Trade in Europe

A. *A First Look at The Data*

PRODUCTION CAPACITIES, MARGINAL TECHNOLOGIES, AND DEMAND.—Despite the fact that European countries have (in principle) access to identical generation technologies, the existing technology mix of electricity production capacities varies considerably by country.[4] Technology-specific marginal costs and installed generation capacities define the supply curve for domestically produced electricity in each country. In the absence of international trade, hourly equilibrium prices for electricity in each country are determined by the available capacity of the least-cost technology to meet demand in this hour, i.e. the "price-setting" or "marginal" technology.

Table 1 compares installed generation capacities, ordered by marginal cost[5], with the

[4]While this is not the focus of this paper, observed differences in production capacities are a result of a multitude of factors such as the local abundance of fossil and renewable resources, the size and variation of electricity demand (e.g., driven by industry structure), transmission infrastructure, regulatory conditions, path-dependent historic investment decisions, and political and societal preferences.

[5]Based on Schröder et al. (2013) and Traber and Kemfert (2011), we assume the following marginal cost ranking

yearly average of hourly demand, and lists for each country the average marginal technology needed to cover yearly average demand. Although temporal resolution is suppressed here, Table 1 gives a first idea of cross-country differences in marginal generation costs as determined by size and technology type of installed production capacities and electricity demand. For example, Norway, Germany, France, and Switzerland cover their average domestic demand by relatively cheap hydro, coal, or nuclear generation whereas countries such as Spain, Italy, and the UK use more relatively costly natural gas technology. On average and for the European fleet as a whole, natural gas is the average marginal generator. All countries show an excess in installed generation capacities relative to yearly average demand ranging from 22% to 138%. In absolute terms, in particular France, Germany, and Poland—which are characterized by relatively inexpensive average marginal technologies—show high excess capacities. Existing cross-country differentials in marginal costs together with significant excess capacities indicate large potentials for electricity trade.

While Table 1 masks demand variations at the sub-annual level, Figure 2 shows for the four largest European economies (France, Germany, UK, Spain) the empirically observed frequency distribution of hourly electricity demand (ENTSO-E, 2013*a*) alongside with the marginal technology that would be used in a given hour *assuming that domestic demand would have to be met entirely by domestic production.* The horizontal axis plots cumulative capacity or demand (both in GW). Panel (a) is based on observed hourly demand while Panel (b) shows the distribution of hourly demand net of RE production from wind and solar given the observed hourly production profiles for individual countries in 2012 (see Appendix B for details on data). For example, France is shown to have a total cumulative capacity of almost 80 GW. Given the hourly distribution of electricity demand, about 55 GW of demand would be met in hours with nuclear as the marginal technology. Installed coal-fired capacity is about 5 GW implying that about 60 GW of demand could be met with coal as the marginal technology.[6] The graphs also show the frequency of hours with "uncovered" demand, i.e., hours in which demand exceeds what could be produced with domestic capacities.

A number of key insights emerge from this graph—all suggesting considerable scope for two-way cross-border electricity trade in Europe. First, for a vast majority of hours over a year, nuclear, coal and natural gas are the price-setting, marginal technologies in Europe.[7] Second, there exists considerable excess production capacities for a large number of hours.[8] Third, for some countries (e.g., France), demand cannot be met domestically during a large number of hours over the year. Fourth, the shape of the distribution of hourly load varies considerably across countries which means that hourly demands are imperfectly correlated across countries. Median and variability differ across countries. Fifth, adding RE to the picture—comparing Panel (a) with (b)—shifts marginal costs schedules to the right. For

of technologies (from low to high): hydro, other (mainly biomass and waste), nuclear, coal, natural gas, and oil. See Section III for further details.

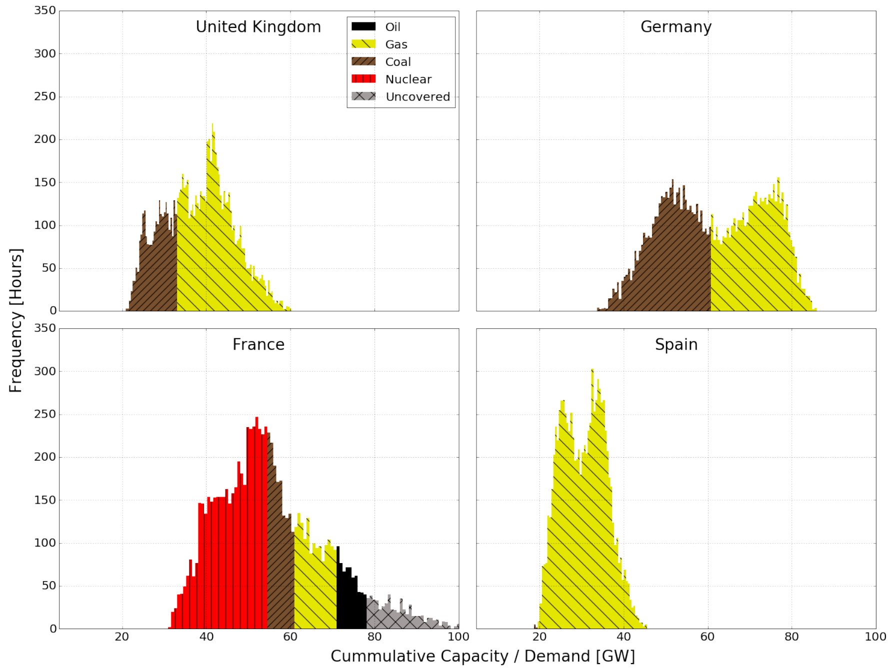
[6] Note that Figure 2 does not show installed production capacities of technologies that are "below" the marginal technology. In the example of France, there is 10 and 20 GW of installed hydro and biomass capacity, respectively.

[7] For some Nordic countries, Switzerland, and Austria that have rich endowments of water resources, there exists a large number of hours in which hydro power is the marginal technology.

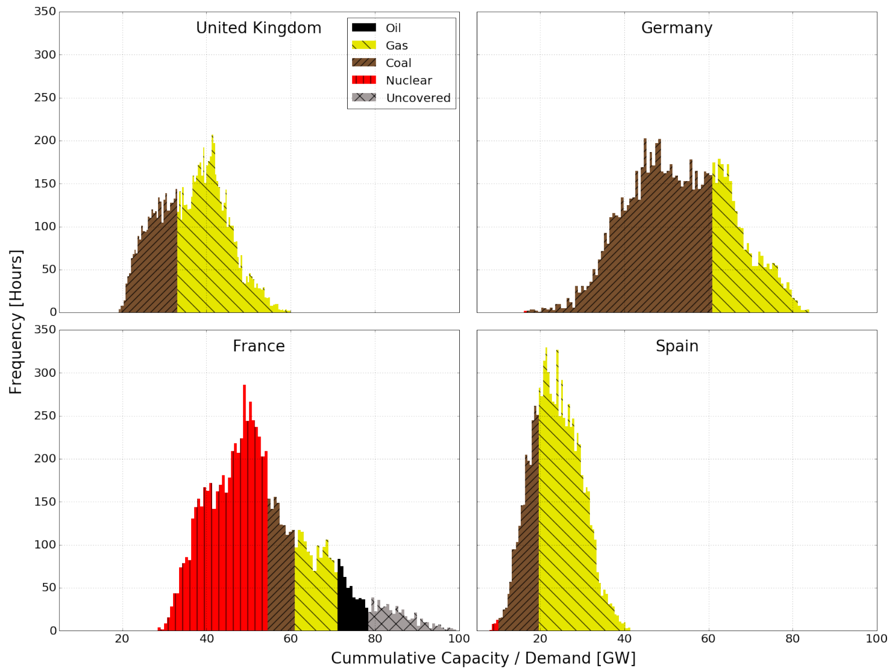
[8] For example, to meet median demand in France and Germany only about 55% and 62% of total capacity, respectively, are needed.

Figure 2. Frequency distribution of hourly electricity demand, (availability-adjusted) installed production capacity, and marginal technologies (for selected European countries)

(a) Demand



(b) Residual demand (i.e., demand net of RE production from wind and solar)



countries with relatively large penetration of RE (e.g., Spain and Germany), this implies a higher frequency of hours in which low-cost nuclear and coal technologies are price-setting. Sixth, for some countries adding RE does also drastically change the shape of the load distribution. Panel (a) shows that the distribution for Germany and Spain exhibits a bi-modal shape reflecting midday and evening peaks. Around midday when demand is high, solar production is at its peak, hence partially "shaving off" the midday demand peak. In fact, Panel (b) shows that the distribution of residual demand looks considerably more uni-modal when RE production is taken into account.

CROSS-COUNTRY CORRELATION OF ELECTRICITY DEMAND.—Ceteris paribus electricity trade between two countries is the larger, the lower is the cross-country correlation between demands. Intuitively, if demand in country A is low while being high in country B, idle production capacity in A can be used to meet high demand in B. If cross-country demands would be perfectly positively correlated, then smaller trade volumes would be expected for given price cross-country differentials.

Empirically, the cross-country correlation coefficients of hourly electricity demand in our sample are significantly below unity. If variability from RE production profiles is added—i.e., considering *residual* demand—cross-country correlations are further decreased. The mean and standard deviation for the distribution of correlation coefficients in our sample is 0.75 and 0.13, respectively; these values are reduced to 0.65 and 0.16, respectively, when RE generation is taken into account.

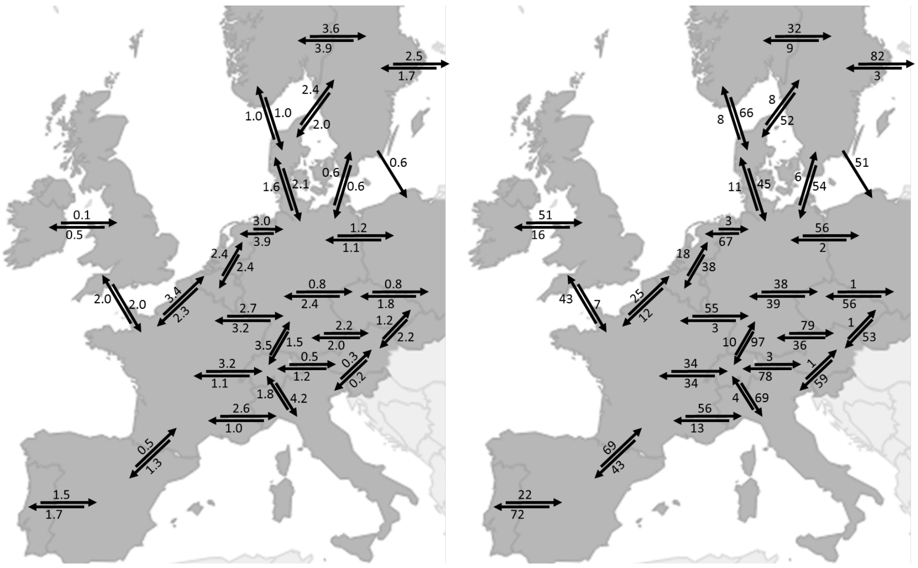
Correlation patterns of electricity demand that extend over seasonal scales are also important drivers of cross-border electricity trade. For example, comparing France and Germany shows that France has incentives to export during summer times but to import during winter times (the latter being mainly due to electricity-based heating). On the other hand, comparing Spain against the UK illustrates the point that South European countries are typically described by an additional demand peak in summer due to cooling demand.

CROSS-BORDER TRANSMISSION CAPACITIES.—Unlike other commodities, electricity trade is grid-bound and restricted by the existing TI. This implies that even if cross-country differences in production cost exists, trade is constrained by limited cross-border transmission capacities. Figure 3a shows the Net Transfer Capacity (NTC) between pairs of geographically contiguous countries for the current European grid;[9] Figure 3b reports average annual utilization rates of NTCs. The picture that emerges from looking at average utilization rates suggest a North-South pattern of electricity trade (for example, cheap electricity flowing from the Scandinavian countries to Germany and via Switzerland further to Italy). Given the existing NTCs, the current European grid features four geographical areas—the Iberian Peninsula, Italy, UK, and the Scandinavian countries—that are relatively poorly connected with the central part of continental Europe which forms itself a relatively tightly integrated electricity market. The degree of electrical insularity for these regions due to low levels of existing NTCs is significant, and is, for example, reflected by

[9]Net Transfer Capacities indicate the maximum amount of electricity that can be transported across an installed electricity line. Importantly, they also take into account the possibility to transport electricity from the border to another node in the electricity network within a region.

Figure 3. Net Transfer Capacitiesa (NTC) and average utilization[b]

(a) NTCs (GW) (b) Annual utilization rates (%)



Notes:[a]Based on ENTSO-E (2011). [b]Average utilization of cross-border transmission capacity is calculated as the percentage fraction of physical energy flows in 2012, as observed by ENTSO-E (2012), divided by the number of hours in a year, relative to installed NTC.

relatively low ratios of the interconnection capacity to peak load.

B. *Gauging the Scope for Cross-Country Trade: How Large Are Price Differentials?*

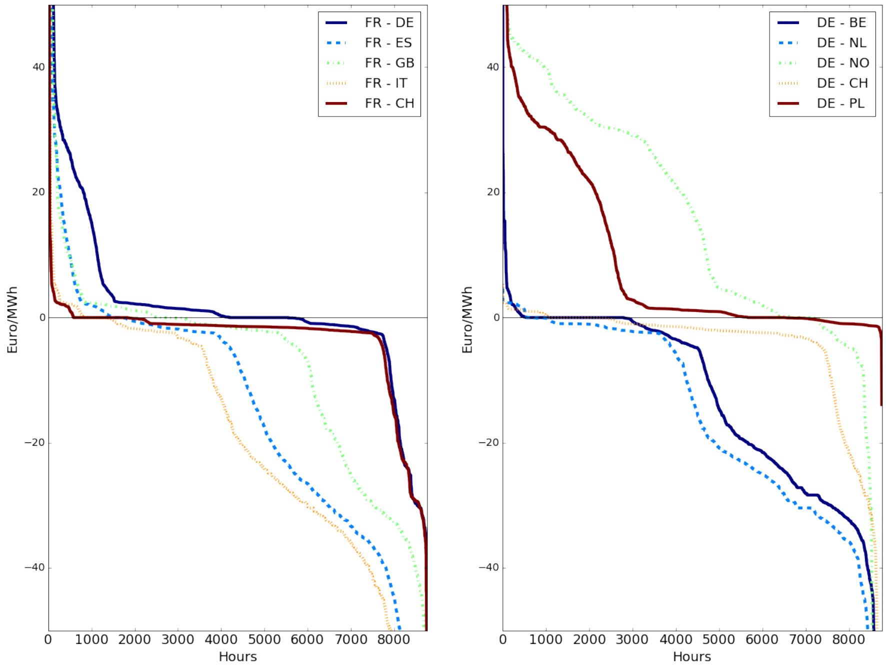
Given the observed cross-country differences in terms of installed production capacities, marginal generation technologies, temporal variations in and imperfect correlations of electricity demand, how large are the economic incentives for international electricity trade between European countries and, hence the scope for TIP directed at promoting trade?

We find that there exist high frequencies of sizeable electricity price differences between countries for which a direct cross-border connection exists.[10] For Europe as a whole, in more than half of hours in 2012, the cross-country price difference exceeded 2 €/MWh, and 35% and 10% of the time price differentials exceeded 10 and 30 €/MWh, respectively.

The aggregate view masks sizeable price differences for specific country pairs. Figure 4 shows the cumulative distribution of hourly cross-country price differences for France

[10]Our price data is based on simulated bulk power wholesale prices obtained from baseline assumptions of our simulation model representing the current situation (as of year 2012) with respect to existing transmission infrastructure, generation capacities, and RE generation. Price differences in our model arise because transmission constraints are binding. If, for a given hour, transmission constraints between any two countries are non-binding, prices are equalized (there is still some deviation as we assume line losses associated with transmission). Section III describes the model and further details the assumptions underlying our simulation analyses.

Figure 4. Cumulative annual frequency of hourly price differences for selected country pairs for current transmission infrastructure and renewable energy production



and Germany and their neighboring countries. The graphs displays for any given price differential (on the vertical axis), the number of hours over the entire year (on the horizontal axis) for which the price difference between France and Germany and one of their respective neighbors was at least as large as the corresponding value on the vertical axis.

Figure 4 bears out a number of important insights. First, hourly price differences are as large as 40 Euro/MWh while yearly average electricity prices are between 50 to 70 Euro/MWh. Second, for many country pairs in our sample, electricity price differentials are not unidirectional. For most countries there exist many hours over the period of a year in which the price is higher and lower than in the neighboring country. For example, for most hours France exhibits a lower price than Italy (mainly due to its abundance of cheap nuclear power); there are, however, some hours in which the price differential is reversed (due to gas or oil instead of nuclear being the price-setting technology in France). Third, for other countries, Figure 4 suggests a strong unidirectional cost advantage. For example, for the majority of hours over a year Germany could import cheap hydro power from Norway while it could export relatively cheap electricity (mainly from coal and RE) to Switzerland, Poland, and the Netherlands.

III. Description of Model and Data

This section describes the numerical general equilibrium model that incorporates the above-mentioned drivers of cross-country electricity trade and which we use to assess the

Table 2. Overview of model resolution: regions, sectors, and electricity generation technologies.

Regions ($r \in R$)	Austria, Belgium, Czech, Denmark, Finland, France, Germany, Ireland, Italy, Netherlands, Norway, Poland, Portugal, Spain, Sweden, Switzerland, UK, Rest of Europe, Rest of World
Sectors ($i \in I$)	Coal, Natural gas, Crude oil, Refined oil, Electricity, Agriculture, Services, Transportation, Energy-intensive industries, Other industries
Electricity generation technologies ($p \in P$)	Coal, Gas, Hydro, Nuclear, Oil, Pump hydro storage facilities, Other (mainly biomass)

economic and CO_2 emissions impacts of enhanced transmission infrastructure. We also briefly describe how we apply data from various sources to our calculations. Appendixes B and C provide additional information on the data sources for RE generation and a complete algebraic characterization of the equilibrium conditions.

A. Complementarity-Based Formulation of Equilibrium Conditions

Following Mathiesen (1985) and Rutherford (1995), we formulate the model as a mixed complementarity problem, i.e., a square system of nonlinear (weak) inequalities that represent the economic equilibrium through zero profit and market balance conditions determining equilibrium quantities and prices. The complementarity format embodies weak inequalities and complementary slackness and hence allows us to naturally accommodate bounds on specific variables which cannot a priori be assumed to operate at positive intensity; for example, hourly generation being limited by production capacities or international electricity trade constrained by the capacity of a cross-border transmission line.

Electricity generation and storage.—Wholesale electricity firms are assumed to operate under perfect competition maximizing profits using production quantities as the decision variable.[11] Generation units are represented at the technology level where the total production of the representative firm using technology $p \in P$ in hour $t \in \{1, \ldots, T\}$ in region $r \in \{1, \ldots, R\}$ is denoted by X_{prt}. We model a full year, hence $T = 8760$. The set P comprises conventional carbon-based, hydro, and biomass electricity generation plants (see Table 2); generation from wind and solar is modelled exogenously. Production at any point in time cannot exceed given (and fixed) installed capacity cap^X_{pr}

$$cap^X_{pr} \geq X_{prt} \quad \perp \quad PX_{prt} \geq 0 \quad \forall p, r, t\,, \tag{1}$$

where PX_{prt} is the shadow price of capacity for firm p in region r at point t. The marginal cost, c^X_{pr}, of a modeled generation unit depend on its direct fuel, environmental, and variable operation and maintenance (VO&M) costs. Marginal cost are assumed to be constant in output but vary depending on fuel, capital, and labor prices. In addition, firms incur asymmetric adjustment cost associated with increasing their output. This feature reflects flexibility restrictions at the plant level and gives rise to dynamic (marginal) cost

[11] We thus abstract from price regulation and imperfect competition in the electricity sector. We leave for future work the careful comparison of how alternative assumptions about market structure may influence model results.

curves.[12] The increase in output, i.e. the load gradient or ramping amount, between $t-1$ and t is given by[13]

$$X^{+}_{prt} \geq X_{prt} - X_{pr(t-1)} \quad \perp \quad \lambda_{prt} \geq 0 \quad \forall p, r, t\,, \tag{2}$$

where the increase in generation, X^{+}_{prt}, cannot exceed the maximum increase per hour, l_p (expressed in percentage of installed capacity)

$$l_p\, cap^{X}_{pr} \geq X^{+}_{prt} \quad \perp \quad PX^{+}_{prt} \geq 0 \quad \forall p, r, t\,. \tag{3}$$

The amount of generation increase is positive (zero) if the sum of unit ramping costs, c^{+}_{pr}, and the shadow price on the maximum ramping constraint, PX^{+}_{prt}, is equal to (larger than) the shadow value of generation ramping, λ_{prt},

$$c^{+}_{pr} + PX^{+}_{prt} \geq \lambda_{prt} \quad \perp \quad X^{+}_{prt} \geq 0 \quad \forall p, r, t\,. \tag{4}$$

Using marginal generation costs, shadow prices for capacity and ramping, and the price for electricity in region r at time t, PE_{rt}, electricity generation in equilibrium is then determined by the following zero profit condition:

$$c^{X}_{pr} + PX_{prt} + \left(\lambda_{prt} - \lambda_{pr(t+1)}\right) \geq PE_{rt} \quad \perp \quad X_{prt} \geq 0 \quad \forall p, r, t\,. \tag{5}$$

Electricity can be stored using pump hydro storage facilities. Storage facilities are restricted by the size of the reservoir, the installed pumping equipment, and the installed generators. While electricity storage does not incur direct cost, indirect cost are given by the efficiency of the pumping facilities, i.e., storing one unit of energy causes energy losses. The law of motion for the storage's energy content determines the current period energy content depending on the last period storage content and the net storage taking into account losses caused by energy storage. Energy net storage is denoted by N_{rt}.[14]

INTERNATIONAL ELECTRICITY TRADE.—Trade from region r to $\tilde{r}$ is restricted by the fixed and given net transfer capacity between these two regions, $ntc_{r\tilde{r}}$. In line with the idea of "iceberg transport cost" (Samuelson, 1954; Krugman, 1991) and the concept of line losses in electricity network models, some of the cost of cross-border transports of electricity are paid with a portion ϵ of the transported good. The market balancing for net transfer capacities ensures that the transmission line capacity between regions is sufficient to cover

[12] The inclusion of technological restrictions of power plants is a fundamental challenge in electricity dispatch modeling. Gas power plants are usually assumed to be more flexible than nuclear plants in the sense that they can change their output more rapidly. Flexibility restrictions are often represented in unit-commitments models (Baldick, 1995; Padhy, 2004). Due to the usage of binary variables in order to express the status of power plants, unit-commitment modeling is computationally demanding. We thus use a continuous approximation of an unit-commitment model that imposes costs and constraints on output changes per hour to reflect (implicit) flexibility restrictions (see Abrell, Kunz and Weigt, 2008, for a comparison of different approximation approaches).

[13] The load gradient is defined to be positive.

[14] For ease of exposition, we include the conditions determining the equilibrium level of electricity storage N_{rt} in Appendix A.

the trade flows, $T_{r\tilde{r}t}$,

$$ntc_{r\tilde{r}} \geq T_{r\tilde{r}t} \quad \perp \quad PT_{r\tilde{r}t} \geq 0 \quad \forall r, \tilde{r}, t\,, \tag{6}$$

where $PT_{r\tilde{r}t}$ is the shadow price on the transmission line from r to $\tilde{r}$ at a given point in time. Equivalently, $PT_{r\tilde{r}t}$ indicates the degree of congestion on a given transmission line. The model determines the equilibrium patterns of hourly cross-border electricity flows between any pair of regions. Trade flows from region r to $\tilde{r}$ are positive if unit revenue net of transport costs in $\tilde{r}$ is equal to the unit cost (inclusive of a congestion rent) in r, i.e.,

$$PE_{rt} + PT_{r\tilde{r}t} \geq (1-\epsilon)\, PE_{\tilde{r}t} \quad \perp \quad T_{r\tilde{r}t} \geq 0 \quad \forall r, \tilde{r}, t\,. \tag{7}$$

Trade costs of electricity hence comprise line losses which depend on the exogenous parameter ϵ as well as endogenous congestion costs which in equilibrium reflect the utilization of the existing transmission infrastructure.

HOURLY ELECTRICITY MARKET BALANCE AND CURTAILMENT.—Markets for electricity for a given hour and region balance if supply—given by the sum of generation, net storage, and net imports—is equal to residual demand

$$\begin{aligned} &\sum_p X_{prt} + N_{rt} + \sum_{\tilde{r}} \left[(1-\epsilon)\, T_{\tilde{r}rt} - T_{r\tilde{r}t}\right] \\ &\qquad = \beta_{rt} A_{ELEr} - (ren_{rt} - CR_{rt}) \quad \perp \quad PE_{rt} \text{ “}free'' \quad \forall r, t\,. \end{aligned} \tag{8}$$

Residual demand is defined as demand, $\beta_{rt} A_{ELEr}$, net of non-dispatchable renewable energies supply from wind and solar, ren_{rt} and gross of curtailment of wind and solar energy[15], CR_{rt}. The parameter β_{rt} [%] indicates which fraction of yearly demand in region r is distributed to period t. Therefore, we implicitly assume that the demand profile over the year is fixed but the total yearly demand can vary. The supply of wind and solar by region and hour is fixed and exogenous. We allow for the possibility of negative electricity prices, so PE_{rt} is unrestricted in sign, but we assume a lower price bound equal to $p^{min} < 0$ that is uniform across regions and time. The equilibrium level of curtailment for wind and solar is determined by the following condition

$$PE_{rt} \geq p^{min} \quad \perp \quad CR_{rt} \geq 0 \quad \forall r, t\,. \tag{9}$$

PRODUCTION, CONSUMPTION, AND TRADE IN COMMODITIES OTHER THAN ELECTRICITY.— Firms' decisions about electricity generation and international trade are fully integrated into a multi-region multi-sector static general equilibrium model for Europe. The model resolves the major countries in Europe as individual regions and incorporates rich detail in

[15]Curtailment is defined as the amount of renewable energy that is not used to satisfy demand. Although RE are provided with zero marginal costs, it can be optimal to not use them in order to balance demand and supply. This is accommodated by formulating the market clearing condition for electricity as a strict equality which rules out excess supply.

energy use and carbon emissions related to the combustion of fossil fuels (see Table 2 for an overview of the regional and sectoral model resolution). While we focus on a non-algebraic description of the key model features here, Appendix C contains a list of model variables and parameters and provides a complete characterization of the equilibrium conditions. In short, the model solves for mutually consistent profit- and utility-maximizing decisions by firms and households for production, consumption, and international trade of non-electricity commodities that are consistent with market balance conditions.

In each region, consumption and savings result from the decisions of a continuum of identical households maximizing utility subject to a budget constraint requiring that full consumption equals income. Households in each region receive income from two primary factors of production, capital and labor, which are supplied inelastically.[16] Both factors of production are treated as perfectly mobile between sectors within a region, but not mobile between regions. The energy goods identified in the model include coal, gas, crude oil, refined oil products, and electricity. In addition, the model features energy-intensive sectors which are potentially most affected by changes in the price of electricity. All industries are characterized by constant returns to scale and are traded in perfectly competitive markets. Consumer preferences and production technologies are represented by nested constant-elasticity-of-substitution (CES) functions (see Appendix C for more details).

Bilateral international trade by commodity is represented following the Armington (1969) approach where like goods produced at different locations (i.e., domestically or abroad) are treated as imperfect substitutes. Each consumption good is a CES aggregate of domestically-produced and imported varieties. The domestic variety is nested with within-region imported variety where the latter is itself an aggregation of imported varieties from different regions. Investment demand and the foreign account balance are assumed to be fixed.

A single government entity in each region approximates government activities at all levels. The government collects revenues from income and commodity taxation and international trade taxes. Public revenues generated in a given country are used to finance government consumption and domestic (lump-sum) transfers to households (such transfers occur, for example, through social security systems). Aggregate government consumption is represented by a Leontief composite, i.e. inputs are combined in fixed proportions.

Linking electricity supply and economy-wide activities.—The key conceptual challenge for integrating "bottom-up" electricity supply relates to reconciling the different time scales in which we treat electricity generation and economy-wide activities. For each region and hour, the electricity model determines the net supply of electricity, i.e., domestic production (including exogenous RE production, net output from storage, and curtailment of RE sources) plus net international electricity trade. In contrast, economy-wide activities operate on an annual time step.

Using benchmark data on hourly electricity demand (β_{rt}) and denoting the yearly (quantity weighted) average electricity price as PA_{ELEr}, the equilibrium net *annual* supply of

[16] Factor payments to resources are not identified separately but are instead lumped with broad capital.

electricity, A_{ELEr}, is determined by the following zero-profit condition:

$$\sum_t \beta_{rt} PE_{rt} \geq PA_{ELEr} \quad \perp \quad A_{ELEr} \geq 0 \quad \forall r\,. \tag{10}$$

Equation (10) embodies the assumption that consumers' demand reacts on the yearly average of hourly electricity prices our implicit assumption that demand in each hour is scaled proportionally, i.e., own-price demand elasticities are uniform across time. A_{ELEr} appears on the supply side of the market clearing condition for *annual* electricity (see equation (C8) in Appendix C) which, together with endogenously derived demands for final demand categories determines PA_{ELEr}.

On the cost side, electricity firms' decisions depend on marginal costs for generation and ramping, c^X_{pr} and c^+_{pr} (see equations (4) and (5)), which are functions of prices for capital (PK), labor (PL), fuel, and materials inputs (PAE_i):

$$c^X_{pr} = F\left(PAE_{ir}; \eta_p, \alpha_{ip}\right) \qquad \text{and} \qquad c^+_{pr} = G\left(PK_r, PAE_{ir}; \beta_p, \gamma_p\right)\,.$$

η, α, β, and γ are parameters that reflect technology characteristics of electricity generation and ramping technologies (η=heat efficiency, α=variable operation and maintenance (VO&M) costs in generation, β=capital depreciation costs for ramping, and γ=fuel costs for ramping). We assume that electricity generation and ramping technologies are identical between regions. Section III.B provides more detail on our empirical specification of the functions F and G.

The final element for integrating the electricity generation dispatch and trade model into a general equilibrium framework pertains to including income effects for the representative consumer in each region arising from binding constraints on generation, ramping, and cross-border transmission capacity. Note that income effects from binding constraints comprise profits of electricity producers that they earn in the form of sub-marginal rents on installed generation capacity. Moreover, while electricity trade is modelled at the level of the bottom-up model, we do include impacts for the trade balance of each country in the economy-wide equilibrium model through adjusting the income of the representative agent in that region.

B. *Data and Empirical Specification*

SPECIFICATION OF ECONOMY-WIDE ACTIVITIES.—This study makes use of a comprehensive energy-economy dataset that features a consistent representation of energy markets in physical units as well as detailed accounts of regional production and bilateral trade. Social accounting matrices in our hybrid dataset are based on data from version 9 of the Global Trade Analysis Project (GTAP) (Narayanan, Badri and McDougall, 2012). The GTAP9 dataset provides consistent global accounts of production, consumption, and bilateral trade as well as consistent accounts of physical energy flows and energy prices. Version 8 of the database (Narayanan et al., 2012), which is benchmarked to 2011, identifies 129 countries and regions and 57 commodities. We aggregate the GTAP dataset to 20 regions (18

Table 3. Characteristics of electricity generation technologies

Technology ($p \in P$)	Coal	Gas	Hydro	Nuclear	Oil	Other	PSP
Heat efficiency [%] (η_p)	0.4	0.5	–	0.3	0.4	0.5	0.8
Variable OM cost [€/MWh] (α_{ip})	2.6	1.5	2.6	1.0	1.5	2.6	–
Load gradient [% of capacity] (l_p)	0.1	0.5	–	0.0	0.5	0.1	–
Ramping							
Additional depreciation [€/MW] (β_p)	0.2	10.0	–	1.7	5.0	1.7	–
Additional fuel use [MWh/MW] (γ_p)	6.2	4.0	–	16.7	4.0	6.2	–

European countries, and two aggregated regions representing the rest of Europe and the rest of the world) and 10 commodity groups (see Table 2). Primary factors in the dataset include labor and capital.

We use prices and quantities from the integrated economy-energy dataset to calibrate the value share and level parameters using the standard approach described in Rutherford (1998). Response parameters in the functional forms which describe production technologies and consumer preferences are determined by exogenous elasticity parameters. Table C3 in the appendix lists the substitution elasticities and assumed parameter values in the model. Household elasticities are adopted from Paltsev et al. (2005) and commodity-specific Armington trade elasticity estimates for the domestic to international trade-off are taken from GTAP as estimated in Hertel et al. (2007). The remaining elasticities are own estimates consistent with the relevant literature.

ELECTRICITY TECHNOLOGIES, DEMAND, AND CROSS-BORDER TRANSMISSION.—We model the year 2012 with hourly resolution. Hourly demand is based on data from ENTSO-E (2013*a*).[17] For most countries data on hourly renewable generation is available from national transmission grid operators. For cases in which no data is available, we (i) use data on monthly supplies from ENTSO-E (2013*b*), and (ii) derive the hourly profile by imposing the data from the neighboring country.[18] Generation facilities are aggregated on a fuel basis according to the technology categories shown in Table 3.

Parameters of the electricity-sector optimization model are based on engineering cost information and chosen such that observed generation shares by technology and by region are consistent with observed data. Installed generation capacities by fuel type and country are based on the Platts (2013) database. Table 3 displays technology characteristics (heat efficiencies, variable operation and maintenance costs (VO&M), and ramping cost specifications) which are adopted from Schröder et al. (2013) and Traber and Kemfert (2011). Cost functions for generation (F) and the ramping (G) are assumed to be Leontief. NTCs are provided by ENTSO-E (2011). Line losses caused by cross-border electricity trade are assumed to be one percent, i.e. $\epsilon = 0.01$.[19]

[17]ENTSO-E load values are adjusted such that annual totals are consistent published numbers by EUROSTAT.
[18]Table B1 in an appendix details the data sources.
[19]Note that transmission line losses in our model should be viewed as additional losses incurred for cross-border trade on high voltages lines. High voltages lines reduce the fraction of energy lost to resistance relative to low voltage lines. In particular, we do not include losses associated with domestic transmission and distribution for which empirical estimates would be around 5-6% (Energy Information Administration, 2015).

C. Computational Strategy

We formulate the model as a system of nonlinear inequalities and represent the economic equilibrium through two classes of conditions: zero profit and market clearance. The former class determines activity levels and the latter determines price levels. In equilibrium, each of these variables is linked to one inequality condition: an activity level to an exhaustion of product constraint and a commodity price to a market clearance condition. Following Mathiesen (1985) and Rutherford (1995), we formulate the model as a mixed complementarity problem. Numerically, we solve the model in GAMS using the PATH solver (Dirkse and Ferris, 1995).

The aim of the solution method is to compute the vector of price and quantities that solves the system of simultaneous equations given by the equilibrium conditions (1)–(10) and (C1)–(C16). Given the highly non-linear nature and large dimensionality of the numerical problem at hand, an integrated solution approach is not feasible. Moreover, the bottom-up model involves a large number of bounds on decision variables, and the explicit representation of associated income effects becomes intractable if directly solved within a general equilibrium framework. We make use of recent advances in decomposition methods to numerically compute the general equilibrium of the integrated model in the presence of a policy shock.

DECOMPOSITION METHOD.—The electricity sector and economy-wide general equilibrium components are solved based on a block decomposition algorithm by Boehringer and Rutherford (2009).[20] The algorithm involves sequentially solving both components under the same policy shock, ensuring consistency between general equilibrium prices and quantity of electricity produced and associated demand of inputs determined in the electricity generation model.

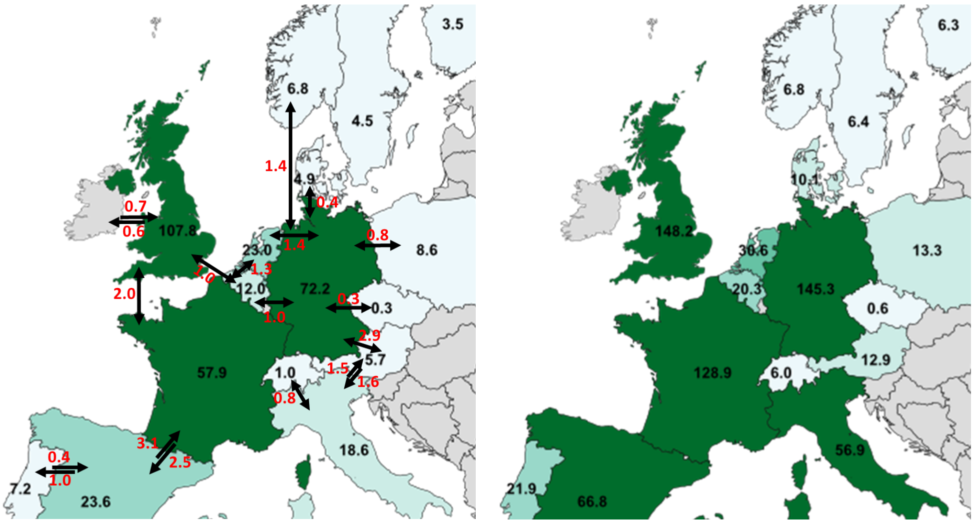
A first step for implementation concerns the calibration of the two sub-models to a consistent benchmark point.[21] To produce a "micro-consistent" SAM, a benchmarking routine was developed for the base-year wherein the electricity market model was solved with historical (fixed) prices for capital, labor, and fuel as well as fixed regional electricity demands. Given electricity supplies and inputs demands, we adjust the SAM data holding fixed the (simulated) electric sector data. Each iteration in the decomposition algorithm comprises two steps, exchanging information for "linking variables" between models. Step 1 solves a version of the CGE model with exogenous electricity production where electricity sector outputs and input demands for fuels, capital, labor, and other materials, are parametrized based on the previous solution of the electricity model. The next solution of the electricity model in Step 2 is based on a locally calibrated set of regional demand functions for electricity and a vector of candidate equilibrium prices for fuels, capital, labor, and materials.

[20]The decomposition method has been applied in a large-scale empirical settings (see, for example, Sugandha et al., 2009, and Rausch and Mowers, 2014).

[21]Initial agreement in the base-year is achieved if bottom-up electricity sector outputs and inputs for all regions and generators are consistent with the aggregate representation of the electric sector in the SAM data.

Figure 5. Increases in cross-border transmission capacities (red, GW) and annual renewable electricity production for wind and solar (black, TWh) underlying the simulation dynamics

(a) Year 2020 (b) Year 2030



Notes: Assumed increases in cross-border transmission capacities for 2030 are identical to those for 2020 and are hence not shown in Panel (b). Not shown is also an additional transmission extension of 700 GW at the border between Belgium and Luxembourg. Figures for NTC increases are shown next to arrows, figures for RE production increases are shown in center of each country.

IV. Simulation Results

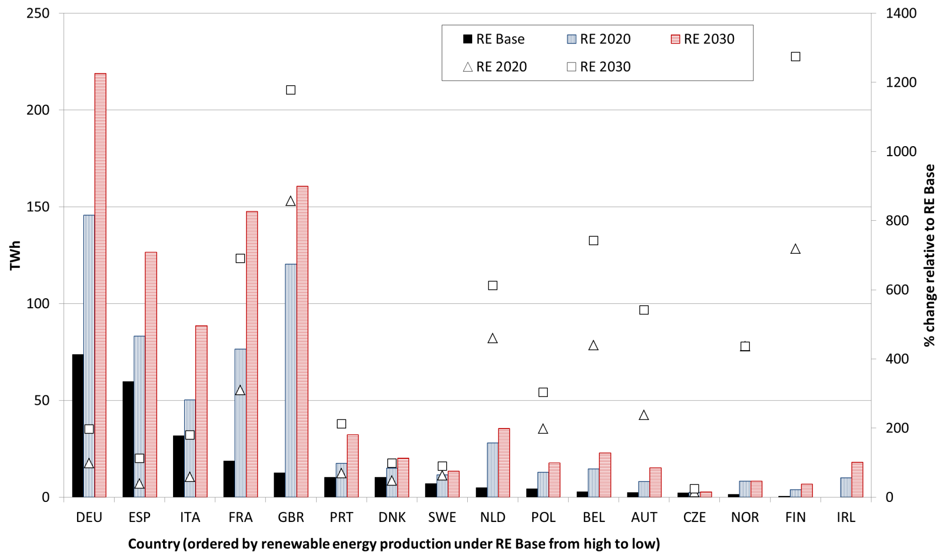
A. *Counter-factual Scenarios*

Given the observed and substantial cross-country differences in terms of installed production capacities, the generation mix, marginal generation technologies, temporal variations in and significantly less-than-perfect correlations of electricity demand, how large is the scope for cross-country electricity trade between European countries? What are the welfare gains if cross-border transmission capacities would be increased from today's levels (or even be non-binding in the limiting case)? To what extent do gains from trade depend on the assumed levels RE production across countries?

We investigate these questions through a series of counter-factual scenarios that are structured along two dimensions. First, we consider exogenously changing the cross-country net transfer transmission capacities represented by the parameter $ntc_{r\tilde{r}}$ in equation (6). The following three cases are chosen to reflect the current transmission network, a future network as under the *Ten Year Network Development Plan*, and a hypothetical case with no constraints placed on the international transmission network:

(i) *"Current"* represents the European cross-border transmission infrastructure existing in 2012.

Figure 6. Historic (year 2012) and targeted (year 2020 and 2030) renewable energy (wind and solar) production by country according to EU Commission (2013)'s climate policy targets



Notes: Squares and triangles show percentage changes which refer to the secondary vertical axis.

(ii) *"TYNDP"* is designed to reflect the (ongoing and planned) expansion of cross-border transmission lines under the *Ten Year Network Development Plan* (ENTSO-E, 2014). Figure 5a visualized the assumed NTC changes underlying the *"TYNDP"* scenario. If fully implemented, the TYNDP will increase total cross-country transmission capacities in Europe from currently 93 to 132 GW, an increase of 41%.

(iii) *"Full integration"* assumes a fully integrated European electricity market where no binding restrictions for cross-border transmission between any pair of countries exist.

A second dimension of the analysis explores the role of alternative levels of RE production from wind and solar for gains from trade due to relaxing cross-country transmission constraints. Increases in exogenous RE production are modeled by changing the parameter ren_{rt} in equation (8). The following cases are chosen to reflect current levels of RE production, and future levels in year 2020 and 2030 as targeted according to EU climate policy:

(i) *"RE Base"* represents a scenario which assumes the 2012 levels of RE production based on historically observed production levels in the year 2012. Hourly RE generation is based on data from national transmission operators; data sources and assumptions are detailed in Section III.B and Appendix B.

(ii) *"RE 2020"* and (3) *"RE 2030"* assume that annual production from RE by country is in line with the official RE 2020 and 2030 targets set forth by the EU Commission (2013), respectively. Figure 5 displays the assumed increases in total annual RE production by country and Figure 6 relates these to the size of existing production from RE.[22] The magnitudes of planned increases are very substantial, especially when viewed relative to current production levels. In summary, annual electricity production from wind and solar at the aggregate European level increases by a factor of 2.5 (3.9) from currently 242 TWh to about 368 (700) TWh in 2020 (2030). Correspondingly, the share of wind and solar in total electricity generation increases from currently 8.3% to roughly 20.4% (31%) in 2020 (2030).

The economic effects of enhanced transmission infrastructure depend on the baseline conditions of economies in 2020 and 2030. In our comparative-static framework, we infer the baseline structure of the model regions for 2012 based on historic data sources (as described in Section III.B). In a second step, we do a forward calibration of the 2012 economies to the target year (2020 or 2030), employing estimates for GDP growth and emissions as well as projections about generation capacities by region and technology and electricity demand based on Energy Information Administration (2013).[23] Finally, the production of RE is treated in an exogenous manner as hourly electricity demand is reduced by hourly generation from wind and solar based on historically observed production data. Moreover, the hourly profiles are assumed to be constant, i.e., given the hourly profiles of RE 2012, we scale them with the expected future levels in 2020 and 2030.

B. *Equilibrium Price and Quantity Impacts for Electricity*

AGGREGATE EUROPEAN-LEVEL IMPACTS.—Table 4 presents the impacts of the TIPs under alternative assumptions about RE production on European-level electricity production, trade, and price. Not surprisingly, increased NTCs induce higher volumes of electricity flows traded among European countries. Under current levels of RE production (*RE Base*), the transmission infrastructure extensions planned under the TYNDP lead to an increase in total within-Europe electricity exports of 67 TWh or 25%; the share of exports in total production increases from 8.9 to 11.2%. While the size of increases in exports brought about by the TYNDP is the bigger, the higher is the level of RE production, the percentage increase in electricity exports does not vary much with RE production. The reason is that, for a given configuration of the European cross-country transmission network, more renewables alone already imply higher levels of trade as the increasing number of zero marginal-cost production possibilities induces higher cross-country price differentials, and hence increases trade incentives (and actual trade flows).

The major impact of increased cross-country TI on the generation dispatch at the European level is to induce a substitution from natural gas to coal-fired electricity. Following the introduction of the TYNDP, the share of natural gas in total electricity production reduces by about 1.0 percentage points with an offsetting increase in coal generation. As more transmission infrastructure is added, a large fraction of the under-utilized and cheap

[22]Hourly production profiles for wind and solar are derived by scaling baseline generation profiles such that annual production targets in 2020 and 2030 are met.

[23]This forward calibration procedure has been used, for example, in Böhringer and Rutherford (2002).

Table 4. Aggregate (European-level) electricity sector impacts

	Renewable energy production								
	RE Base			*RE 2020*			*RE 2030*		
	Cross-country transmission infrastructure								
	Current	*TYNDP*	*Full*	*Current*	*TYNDP*	*Full*	*Current*	*TYNDP*	*Full*
Exports (TWh)	264.3	331.0	485.4	278.5	349.2	507.4	293.8	370.2	531.3
$\%\Delta^a$	–	25.2	83.7	–	25.5	82.1	–	26.0	81.0
Share of exports in production (%)	8.9	11.2	16.4	8.6	10.8	15.7	8.2	10.4	14.9
Generation shares by technology (%)									
Coal	33.7	34.7	36.8	26.6	27.3	28.8	21.5	21.8	22.0
Gas	9.0	7.7	5.0	7.6	6.4	4.0	7.0	6.0	3.9
Nuclear	27.2	27.2	27.3	25.6	25.7	26.0	24.9	25.3	26.3
Solar	2.2	2.2	2.2	4.2	4.2	4.1	5.5	5.5	5.5
Wind	6.0	6.0	6.0	14.7	14.7	14.7	20.9	20.9	20.9
Price (€/MWh)[b]	55.2	56.0	55.9	52.4	52.4	52.3	51.0	50.8	50.9
$\%\Delta^a$	–	1.5	1.1	–	-0.2	-0.4	–	-0.3	-0.2
Curtailment									
% of RE prod.	0.01	0.01	0	0.16	0.09	0	0.61	0.43	0
$\%\Delta^a$	–	-21.7	-100	–	-45.4	-100	–	-30.8	-100.0
Congestion (Γ)	2.2	1.7	0	2.5	2.1	0	3.0	2.6	0
$\%\Delta^a$	–	-24.0	-100	–	-18.4	-100	–	-14.0	-100

Notes: [a]Changes refer to case with current cross-country transmission infrastructure. [b]Yearly load-weighted average of hourly prices.

coal generation capacity is used to export electricity to other countries.

The planned infrastructure extensions under the TYNDP are found to decrease the degree of congestion on the European cross-country transmission system which we measure by the transmission capacity-weighted average of hourly shadow prices that are associated with country-to-country NTC restrictions, Γ.[24] If the TYNDP is introduced, congestion is reduced by 24% under current levels of RE production. The reduction in congestion following the implementation of the TYNDP, however, is decreasing with the level of RE production as more renewables induce higher volumes of cross-country trade for a given transmission infrastructure.

REGIONAL ELECTRICITY PRICE IMPACTS.—Figure 7 shows impacts on yearly-averaged electricity prices by country along the three by three scenario matrix. The top-left panel shows price levels (in €/MWh) under the current TI and year-2012 levels of wind and solar production. Given that cross-country trade is hampered by the existing TI, there exist sizeable cross-country price differences since the technology mix of production capacities and ensuing fuel and generation mixes vary across countries. The central part of continental Europe (Germany, France, Austria, Switzerland) form (more or less) one price zone exhibiting only relatively small price differentials on an annual basis. In contrast, the Iberian Peninsula, Italy, Great Britain, and the Benelux countries each represent a distinct price zone with higher prices than in the central part of Europe. The Scandinavian countries show on average lower prices due to cheap hydro power capacities. Poland and the Czech Republic have lower prices due to cheap coal and nuclear electricity production.

The identified prize zones continue to exist if RE production is increased from current levels to 2020 or 2030 levels, and under future economic conditions, as long as cross-country TI is held fixed (i.e., moving along the first row from left to right in Figure 7). While prices fall for all countries, cross-country price differentials increase. The reason is that the planned additions in RE production are introduced quite asymmetrically across countries (see Figure 6), hence the price decrease induced by RE production, i.e. the merit order effect, varies across countries. Increases in future electricity demand are relatively similar across countries.

Relaxing cross-country TI constraints implies a partial convergence of electricity prices across European countries (i.e., moving down a given column in Figure 7). Countries with initially low prices (Germany, France, Switzerland, Austria, Poland, Czech Republic) experience price increases whereas initially high-price countries (Spain, Italy, UK, Benelux) experience decreases.

While the qualitative pattern of price changes is similar for different TI policies and levels of RE, price impacts vary substantially in size. In general, the higher is the level of RE production, the smaller are the price impacts for a given TI extension. For current levels

[24] In formal terms Γ is defined as

$$\Gamma = \sum_r \sum_{\tilde{r}} \frac{ntc_{r\tilde{r}}}{\sum_{r'\tilde{r}'} ntc_{r'\tilde{r}'}} \frac{\sum_t PT_{r\tilde{r}t}}{T}$$

where T is the total number of hours in a year, and $\lambda_{r\tilde{r}t}$ denotes the hourly equilibrium shadow price on the transmission line from country r to country $\tilde{r}$ at time t. In equilibrium, $PT_{r\tilde{r}t}$ exhibits complementary slackness with respect to condition (6). If the $(r\tilde{r}t)$-transmission constraint is binding (slack), then $PT_{r\tilde{r}t} > 0$ ($PT_{r\tilde{r}t} = 0$).

Table 5. Impact of transmission infrastructure policy on aggregate and regional electric-sector CO_2 emissions under alternative assumptions about renewable energy production

	Renewable energy production					
	RE Base		*RE 2020*		*RE 2030*	
Panel (a)						
Reference emissions under current TIP (mill. tons CO_2)	1027.5		891.3		811.1	
	Cross-country transmission infrastructure					
	TYNDP	*Full*	*TYNDP*	*Full*	*TYNDP*	*Full*
Panel (b): Aggregate (European) level						
Reductions due to RE expansion + TIP[a]						
Δ mill. tons	9.4	30.3	-140.5	-123.5	-222.8	-250.5
Δ%	0.9	3.0	-12.8	-12.0	-21.7	-24.4
Reductions due to TIP alone[a]						
Δ mill. tons	9.4	30.3	5.1	12.7	-6.3	-34.0
Δ%	0.9	3.0	0.6	1.4	-0.8	-4.2
Panel (c): Country level						
Percentage reductions due to TIP alone (for eight largest emitters)[a]						
Germany	2.6	1.5	2.6	4.3	1.9	-0.7
UK	-0.1	1.7	1.9	16.7	-2.0	9.1
Italy	-4.0	-19.4	-4.7	-24.4	-5.0	-32.2
Poland	3.5	29.6	2.4	4.7	1.4	-2.5
Spain	-3.7	-5.9	-5.7	-11.0	-7.8	-15.6
Netherlands	-8.1	-19.7	-7.4	-16.6	-9.6	-18.7
Czech Republic	10.0	20.6	6.3	10.5	3.6	1.4
France	10.7	18.9	10.5	36.1	9.3	52.5

Notes: [a]Changes are relative to case with current cross-country transmission infrastructure.

of RE production, the *TYNDP* induces price changes of up to 5.5 €/MWh. Price impacts tend to get smaller for *RE 2020* and *RE 2030* levels. The reason is that higher levels of RE already induce lower prices for the current TI. The limiting case of *Full integration* is described by substantial price decreases in the Southern countries (in the range of 4-16 €/MWh depending on the level of RE production). In contrast, Scandinavian countries show large price increases on the order of 7-14 €/MWh, countries in the central part of Europe exhibit intermediate price increase of about 1-5 €/MWh.

C. CO_2 *Emissions Impacts of Transmission Infrastructure Policy*

Table 5 presents the aggregate and country-level CO_2 emissions impacts of TIP for different levels of RE production. One rationale for TIP is to help reduce CO_2 emissions from electricity production by using more efficiently "clean" RE which can replace "dirty" fossil-based electricity. Our main finding is that whether or not TIP can bring about a reduction in electric-sector emissions depends on the level of RE production. For low and intermediate levels of RE (*Base* and *RE 2020*), CO_2 emissions increase irrespective of the magnitude of the transmission infrastructure expansion (*TYNDP* or *Full integration*). The

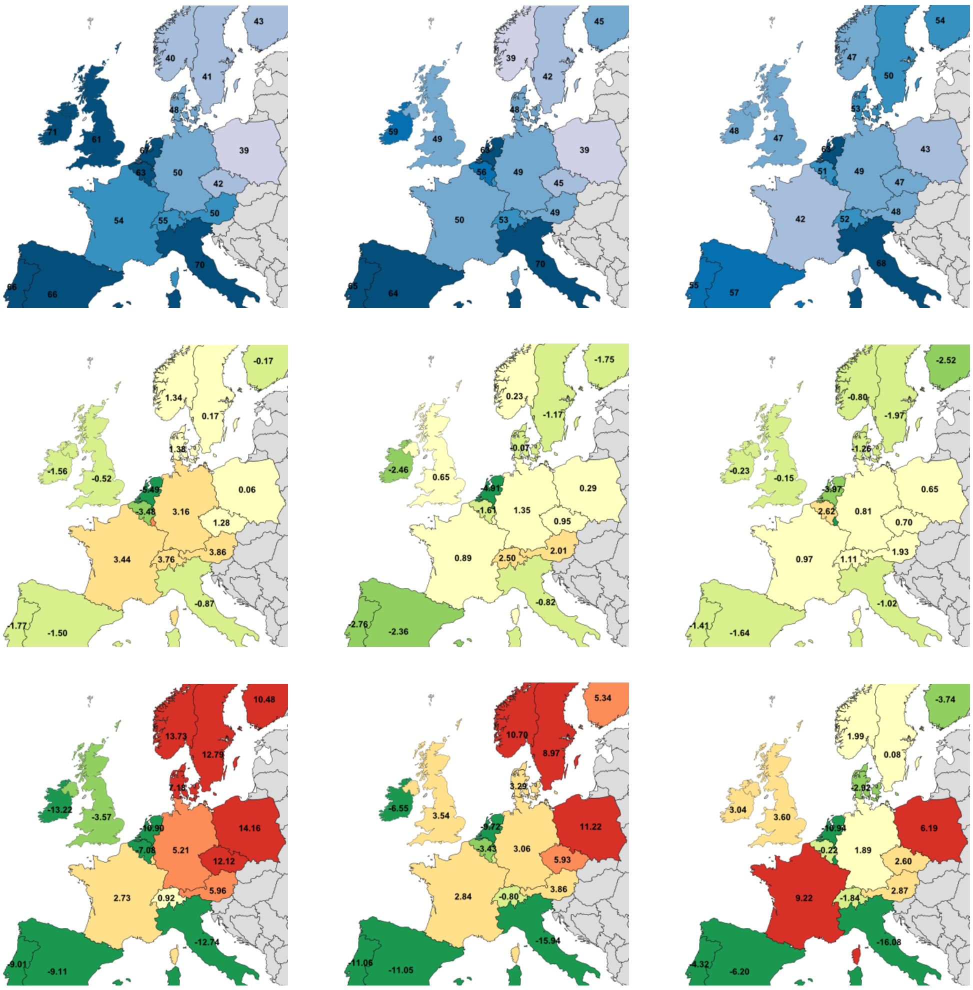


Figure 7. Regional electricity price impacts

Notes: Rows show different assumptions about transmission infrastructure policy: 1^{st}=*Current*, 2^{nd}=*TYNDP*, 3^{rd}=*Full integration*. Columns show alternative levels for RE production and future economic conditions: 1^{st}=*RE Base*, 2^{nd}=*RE 2020*, 3^{rd}=*RE 2030*. First row shows absolute electricity prices (in €/MWh); second and third rows show, for a given column, differences in electricity prices relative to first row.

main driver of this result is that TIP increases economic incentives to produce and export cheap coal-fired electricity resulting in a decrease of gas-fired production. A second effect driving the emissions increase is the boost in overall economic activities brought about by the efficiency gains from cross-country electricity trade. Even for already relatively ambitious level of RE production as envisaged under 2020 EU climate policy targets, we thus find that the TYNDP fails to yield reductions in CO_2 emissions at the European level. In fact, increasing TI beyond what is planned under TYNDP further increases emissions.

For sufficiently large amounts of RE production, however, the TIP is effective in reducing CO_2 emissions as the adverse coal substitution effect is diminished (see Table 4). A larger TI then implies that RE sources—with marginal costs below those for coal—replace coal-fired electricity. Under "*RE 2030*" assumptions, the cross-border transmission expansion consistent with the TYNDP reduces emissions in the European electricity sector by about 1% (relative to the current cross-country transmission system); in the limiting case of fully integrated national electricity markets, the emissions reduction could be as high as 4%. Electricity TIP may thus in the long-term be viewed as an effective complementary measure to EU climate policy objectives; in the transition toward an energy system with high levels of RE sources, reductions in CO_2 emissions are not guaranteed.

TIP creates sizable increases and decreases in CO_2 emissions even if large levels of RE production are assumed. In general, countries with initially low prices and a relatively carbon-intensive electricity mix such as Germany, France, and Poland benefit from enhanced TI by increasing exports and hence emissions. In contrast, countries such as Italy, Spain, and the Netherlands with initially high prices increase there electricity imports which results in a reduction of emissions. We find that under year-2030 RE production the TYNDP creates the smallest increases (or largest decreases) in CO_2 emissions for all countries as compared to cases with low and year-2020 levels of RE production. This suggests that an enhanced TI only benefits environmental outcomes if the level of RE that can be more effectively dispatched is high enough.

D. *Aggregate (European-level) Welfare Impacts*

TRANSMISSION INFRASTRUCTURE POLICY UNDER CURRENT LEVELS OF RE PRODUCTION.— Table 6, Panel (a), presents the welfare impacts from increased cross-border TI at the aggregate European level (as measured by the change in Hicksian equivalent variation). Assuming that RE production would remain at today's levels, increasing the transmission capacity in line with the TYNDP is found to produce efficiency gains on the order of 0.02 percent or 1.62 billion\$ per year. Not surprisingly, the macro-economic welfare impacts are small as the value share of electricity output in economy-wide consumption (or GDP) is relatively small (around 4%).[25] Profits in the electricity sector increase substantially by about 20%.

Our analysis suggests that substantially higher gains from international electricity trade are possible if additional cross-border lines, beyond what is envisaged under the TYNDP, would be implemented. In the limiting case of fully integrated electricity markets—while assuming current levels of renewable electricity production—the efficiency gains could be on the order of 0.06 percent (measured as Hicksian equivalent variation in percent of full

[25] Booz & Company and Noel (2013, p.4) analyze the potential for market coupling in the European electricity sector and find comparable gains on the order of 2.5-4 billion €. Neuhoff et al. (2013) estimate that annual savings in system variable costs from full electricity market integration in Europe range from 0.8-2 billion €. One should bear in mind, however, that a comparison between different studies is notoriously difficult. For example, Booz & Company and Noel (2013) consider the gains from European market coupling, which in addition to an enhanced network, also comprises harmonizing market design and other elements. Further, our welfare metric is based on general equilibrium approach whereas they use a partial equilibrium analysis.

Table 6. Aggregate welfare gains from transmission infrastructure policy (relative to current infrastructure) under alternative assumptions about renewable energy production

	Renewable energy production					
	RE Base		*RE 2020*		*RE 2030*	
	Cross-country transmission infrastructure					
	TYNDP	*Full*	*TYNDP*	*Full*	*TYNDP*	*Full*
Panel (a): Impacts on welfare and electricity sector profits						
Annual welfare gains						
%Δ in Hicksian Equivalent Variation	0.02	0.06	0.02	0.07	0.02	0.08
Billion$	1.62	6.49	2.62	8.45	3.31	11.63
Percentage change in electricity-sector profits	20.2	46.3	6.9	20.6	3.5	10.3
Panel (b): Decomposition of income changes (bill.$)						
Income changes due to electricity-sector adjustments						
Revenues from domestic & foreign (intra-EU) trade	1.61	2.67	0.11	0.32	-0.14	-1.10
Production cost savings	2.13	5.91	2.24	6.65	2.56	8.26
Income changes due to economy-wide adjustments[b]	-2.12	-2.09	0.27	1.48	0.89	4.44

Notes: [b]Calculated as residual of difference between total welfare change (in billion$) and sum of income changes due to electricity-sector adjustments.

income) or about 6.49 billion$ per year.[26] While such a case of course remains hypothetical, it points to the inefficiencies of the existing European electricity market which stem from the limited interconnectedness of the many national electricity markets. Loosening up cross-country trade restrictions over and above the planned TI expansion under TYNDP would allow countries to more efficiently share resources for and exploit cost advantages of producing electricity with ensuing positive effects on (European) welfare.[27]

ALTERNATIVE LEVELS OF RE PRODUCTION.—A key insight of Table 6, Panel (a), is that for a given increase in cross-border transmission capacities, welfare gains are the higher, the larger is the level of RE production. Gains from trade due to the TYNDP increase by 62% and 204% for 2020 and 2030 targets relative to the *RE Base* scenario. Intuitively, as many countries add significant amounts of RE production from wind and solar, the number of zero (or low) marginal-cost production possibilities increases. Given an increase in cross-country TI, low marginal-cost production possibilities can be more efficiently shared via international electricity trade, in turn implying larger welfare gains as compared to a situation with less RE production.

Cross-country electricity trade, enabled by an enhanced TI, is therefore pivotal for capturing the benefits from RE generation. International electricity trade represents a flexibility mechanism which can lower the costs associated with the deployment of RE. At the same time, the economic value of cross-border transmission capacity increases with the level of RE production.

DECOMPOSITION OF REAL INCOME CHANGES.—What drives welfare impacts? How large

[26]Of course, these would have to be traded-off against the investment costs for building the corresponding TI. We refrain here deliberately from providing what would be highly uncertain and arbitrary investment cost estimates for "unlimited" TI.

[27]It is beyond the scope of this paper to determine the optimal cross-country transmission infrastructure, including the question which lines between any country pair would yield the largest welfare gains.

are interactions between the electricity sector and the broader economy? In order to obtain insights into these questions, we decompose real income changes into the following four components: (1) revenue changes from domestic and foreign electricity trade, (2) electricity production cost changes, and (3) income changes due to economy-wide adjustments.[28] The first two components indicate income changes due to adjustments in firms' behavior in the electricity sector; the difference between the revenues and production cost in the electricity sector provides a measure of the change in electricity firms' profits. The third component in the decomposition capture changes arising from general equilibrium interactions with the macro-economy.

Table 6, Panel (b), provides a decomposition of real income changes at the aggregate (European) level. Not surprisingly, the TI extension brings about a reduction in the costs of electricity production in all scenarios as increased trade opportunities mean that low cost production options can be more efficiently used across countries. For a given TI expansion, the positive impact on production cost savings increases with the level of RE production as zero (low) marginal-cost production possibilities from wind and solar can be utilized more efficiently. In the aggregate European perspective, revenues from domestic and foreign (intra-EU) electricity trade increase contributing positively to real income. This may seem at first glance counter-intuitive as one might expect that increased cross-border electricity trade tends to reduce prices, so given small changes in the quantity of electricity demanded, the change in revenues should be negative. However, overall revenues increase because large countries such as Germany and France experience price increases that overcompensate negative revenue changes in relatively small countries (compare with Figure 7). For higher levels of RE production, the positive contribution to welfare from revenue increases diminishes as price increases tend to be smaller and the overall quantity of electricity traded slightly reduces. In summary, changes in electricity-sector profits (i.e., change in revenues plus cost savings) increase by about 9 to 45% depending on the TIP and the level of RE production.

Real income changes due to economy-wide interactions are quantitatively significant relative to changes stemming from electricity-sector adjustments. Electricity prices increase in most of the large countries which leads to increases in consumer prices implying a loss at the aggregate level. Increases in electricity-sector profits and decreases in electricity prices in some countries boost economic production driving up capital and labor demand with a positive effect on real income. While at the aggregate level the combined effect on real income is small relative to electricity-sector effects, the importance of capturing the full general equilibrium welfare effects will become more apparent at the regional level.

E. *Country-level Welfare Impacts*

Figure 8 presents regional welfare impacts from increasing TI as assumed in the *TYNDP* and *Full integration* scenarios (i.e., moving down a given column) for alternative levels of RE production as is reflected by current, year-2020, and year-2030 scenarios (i.e., moving

[28]Given the issue that any welfare decomposition in a general equilibrium model depends on the choice of numeraire, we focus here on decomposition changes in real income.

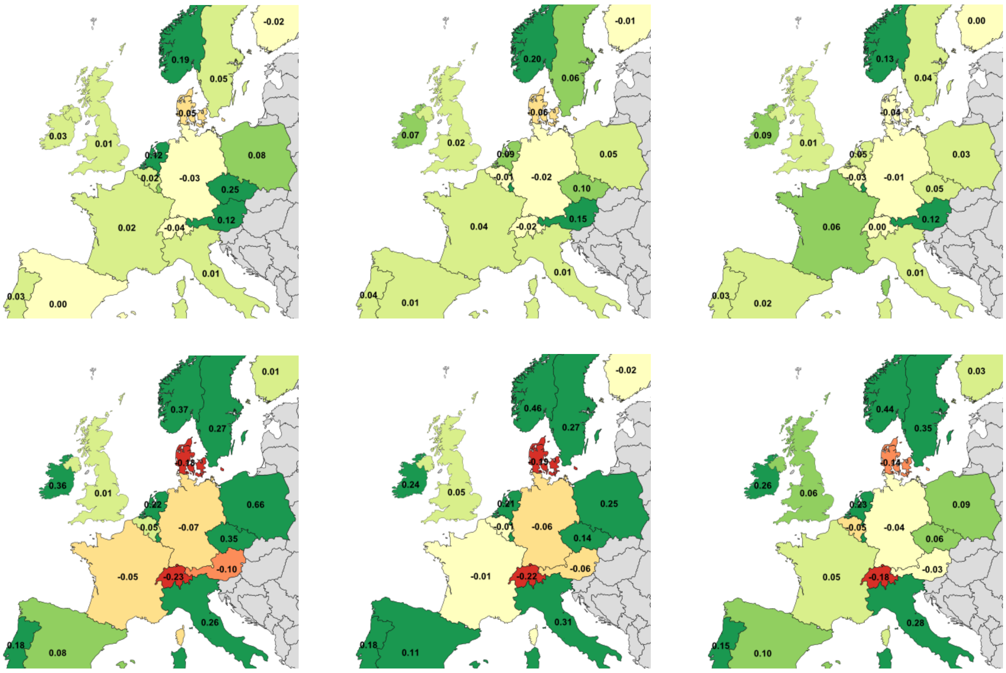


Figure 8. Welfare impacts of TIP by country for alternative assumption about RE production

Notes: Rows show different assumptions about TIP: 1^{st}=*TYNDP*, 2^{nd}=*Full integration*. Columns show alternative cases for RE production: 1^{st}=*RE Base*, 2^{nd}=*RE 2020*, 3^{rd}=*RE 2030*. For a given level of RE production, welfare impacts are expressed in percentage changes relative to the base case reflecting assumption about the current European TI.

from left to right for a given row). The following key insights are borne out by Figure 8. First, the vast majority of countries gain from TI expansion under the TYNDP (first row).[29] The mostly positive regional incidence suggests that regional equity concerns may be not constitute a major obstacle for the implementation of the TYNDP, i.e., most of the projects indeed create mutually beneficial outcomes—even when taking into account broader socio-economic impacts beyond the electricity sector. Second, consistent with the aggregate welfare perspective, regional gains tend to be larger, the higher is the level of RE production. This again underscores the importance of the planned TI extension in light of increased future RE production. Third, while most countries gain, some countries, namely Germany, Denmark, and Switzerland, experience welfare losses from the TYNDP.

What explains the differences in sign and magnitudes of country-level welfare impacts? Economic drivers of welfare impacts can be best understood by grouping countries into three categories: (1) exporting countries, (2) importing countries, and (3) "wheeling" or transit countries. For each category, we provide (at least) one example of a particular

[29]We abstract from the regional incidence of investment costs from enhanced transmission infrastructure.

Table 7. Regional welfare impacts and decomposition of income changes for selected countries from TYNDP transmission infrastructure policy under year-2020 renewable energy production[a]

Country	Denmark	Germany	France	Italy	Spain
Total welfare impact	-0.12	-0.46	0.83	0.10	0.09
Income changes due to electricity-sector adjustments					
Revenues from domestic & foreign trade	-0.01	0.49	0.26	-0.18	-0.38
Production cost savings	-0.04	-0.26	-0.12	1.19	0.74
Exports	0.11	1.06	0.90	0.00	0.07
Imports	-0.15	-0.84	-0.07	-1.20	-0.86
Income changes due to economy-wide adjustments[b]	-0.17	-2.36	-1.93	-1.01	-0.50

Notes: [a]All numbers refer to welfare change in billion$ relative to current transmission infrastructure. [b]Calculated as residual of difference between total welfare change (in billion $) and sum of income changes due to electricity-sector adjustments.

country and decompose the drivers of welfare impacts in Table 7. Among the countries which experience the highest welfare gains are both exporting and importing countries. For example, Italy as a large net importer benefits from significant cost savings in domestic production and increases in factor income created by higher activity following a decrease in electricity prices. In contrast, France as a large net exporter, gains due to increases in both electricity-sector profits and revenues from international electricity trade, overcompensating welfare losses due to a higher CPI and reductions in factor income. Similarly, exporting countries such as Norway, Austria, Poland, and Czech Republic overall gain largely due to selling their relatively cheap electricity produced from hydro, coal, or nuclear power.

Denmark and Switzerland as large "wheeling" countries for electricity lose under the *TYNDP*. As a result of the new transmission line from Norway to Germany, Norway obtains at the expense of Denmark rents from international electricity trade with Germany. In addition, electricity prices in Denmark increase implying negative CPI and factor income effects. Similarly, Switzerland experiences losses due to significant transmission infrastructure added at the Austrian-Italian border implying that Austria can sell cheap hydro power directly to Italy thus circumventing Switzerland. Germany, as a net exporter (on an annual basis), experiences a welfare loss despite increased revenues from international trade as higher electricity prices negatively impact welfare due large negative economy-wide adjustments.

Fourth, the pattern of the regional distribution of gains from increased cross-country electricity trade is roughly similar for the *Full integration* cases as compared to the *TYNDP* scenario. While welfare losses for the "wheeling" countries become larger, the gains for importing countries (such as Italy and Spain) and net exporters in the Scandinavian countries and Eastern Europe (Poland and Czech Republic) increase. The large net exporting countries Germany and France which initially exhibit relatively low electricity prices, however, incur larger losses or smaller gains as compared to the *TYNDP* scenario as electricity prices increase strongly hence resulting in negative welfare impacts due to economy-wide interactions from factor income and CPI.

V. Conclusions

This paper has developed a multi-country multi-sector general equilibrium framework, integrating high-frequency electricity dispatch and trade decisions, to study the effects of electricity transmission infrastructure expansion and renewable energy penetration in Europe for the regional distribution of gains from trade and CO_2 emissions from electricity production.

Our analysis highlights the central role played by infrastructure for environmental outcomes. An enhanced transmission infrastructure for electricity might, on the one hand, complement emissions abatement by mitigating dispatch problems associated with renewables but may, on the other hand, promote higher average generation using carbon-intensive low-cost fossils (e.g., coal). Importantly, how transmission infrastructure impacts emissions depends on contemporaneous renewable energy policy affecting the amount of low-cost renewables which can be more effectively distributed in an enhanced grid. Using a calibrated general equilibrium model, we find that planned transmission infrastructure in Europe increases emissions even for relatively high levels of renewables as targeted for the year 2020 under European energy and climate policy; only for high levels as targeted for the year 2030, we find that emissions decline. An important implication of our analysis is that "environmentally friendly" but spatially uncoordinated RE policies in a highly developed grid bear the risk of unintended consequences in the form of degraded environmental outcomes and emissions leakage. While the problem is only transient and will eventually disappear once the RE penetration is sufficiently large, our findings point to the need to consider a coordinated emissions and infrastructure policy.

Another important finding is that enhanced transmission infrastructure has the potential to bring about sizeable gains from trade at the aggregate (European level), estimated to be on the order of 1.6-2.6 billion 2011$ per year (corresponding to an 0.02-0.03% increase in annual welfare). Gains from trade depend positively on renewable energy penetration. On the regional dimensions, enhanced transmission infrastructure brings about gains from trade for the large majority of countries with only small loss for some "wheeling" (electricity transit) countries. This supports the view that increased electricity trade through transmission infrastructure policy increases efficiency and does not result in strong adverse equity implications.

Our paper is a first step toward analyzing the interactions between transmission infrastructure, renewable energy penetration, and environmental outcomes. Several directions for future research appear fruitful—while at the same time pointing to the caveats for the analysis presented here. First, the model is consistent with the notion of an operational equilibrium but not an investment equilibrium as investments in generation capacity are represented exogenously. It is, however, not clear in what direction investment incentives would be affected by an enhanced transmission infrastructure. A part of this answer depends on a number of aspects related to RE from which we have abstracted. First, we do not incorporate technological change which could further lower the costs of RE technologies relative to conventional technologies. Second, while our model captures the hourly variability of RE production and impacts on curtailment, it cannot deal with effects arising from stochastic intermittency issues such as, for example, a decreasing forecast error of wind due to a more effective dispatch of RE over an enhanced grid exploiting imperfect correlations across geographically more dispersed sites. As a result, an expanded grid could boost the availability factor of RE as a technology class and importantly lowers their cost. This could weaken our finding that enhanced transmission infrastructure, in the short-run, degrades environmental outcomes (i.e., increases CO_2 emissions). At the same time, however, much of the existing excess coal capacity is already depreciated and would hence not be retired (even if investment and retirement decisions were endogenous). On the other hand, price convergence triggered by enhanced infrastructure increases (decreases) electricity prices for initially low (high) price countries. Without a systematic model, it is hard to gauge how investments, in particular on a regional level, would be affected in a system of electricity markets that becomes increasingly interconnected.

Second, local costs associated from the siting and construction of transmission infrastructure are not considered as part of the investment cost. Third, our analysis focuses on centralized generation. Breakthroughs in distributed generation could have yet another important effect on the value of transmission capacity. Lastly, it would be interesting to study more closely the interactions between climate and energy policies and transmission infrastructure policy.

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Appendix A: Equilibrium Conditions for Electricity Storage

Storage facilities are restricted by the size of the reservoir cap_r^L, the installed pumping equipment cap_r^W, and the installed generators cap_r^V according to:

(A1) $$cap_r^L \geq L_{rt} \quad \perp \quad PS_{rt}^L \geq 0 \quad \forall r, t\,,$$

(A2) $$cap_r^W \geq W_{rt} \quad \perp \quad PS_{rt}^W \geq 0 \quad \forall r, t\,,$$

(A3) $$cap_r^V \geq V_{rt} \quad \perp \quad PS_{rt}^V \geq 0 \quad \forall r, t\,,$$

where PS_{rt}^L, PS_{rt}^W, and PS_{rt}^V denote the respective shadow prices on the capacity constraints. While electricity storage does not incur direct cost, indirect cost are given by the efficiency of the pumping facilities η. Thus, storing one unit of energy causes losses of $1-\eta$ units. The law of motion for the storage's energy content (**??**) determines the current period energy content depending on the last period storage content and the net storage taking into account losses caused by energy storage and expressed by the efficiency η:

(A4) $$L_{r(t-1)} + \eta W_{rt} - V_{rt} = L_{rt} \quad \perp \quad PS_{rt}\text{free} \quad \forall r, t\,.$$

Net storage is defined as $N_{rt} = V_{rt} - W_{rt}$. The equilibrium level of the reservoir, pumping, and the storage output are given, respectively, by following conditions:

(A5) $$PS_{r(t+1)} + PS_{rt}^L \geq PS_{rt} \quad \perp \quad L_{rt} \geq 0 \quad \forall p, r, t\,,$$

(A6) $$PE_{rt} + PS_{rt}^W \geq PS_{rt} \quad \perp \quad W_{rt} \geq 0 \quad \forall p, r, t\,,$$

(A7) $$\eta PS_{rt} + PS_{rt}^V \geq PE_{rt} \quad \perp \quad V_{rt} \geq 0 \quad \forall p, r, t.$$

Appendix B: Data on Renewable (Wind and Solar) Generation

We have collected renewable generation profiles over the year 2012 for European countries from websites of the respective grid operators. Table B1 shows the sources used for wind and solar data. Most operators provide an hourly or finer resolution of these data. For countries with unavailable data, the hourly profile of next neighbor available together with monthly generation provided by ENTSO-E is used. In order to merge the different data source to a consistent data set, we first aggregate all renewable data to an hourly basis. Moreover, all values are converted to the UTC timezone taking regional daylight saving rule into account. 2012 was a leap year but the additional day is not provided in all data source. Thus, the additional leap day is removed from the data.

Table B1. Data sources for hourly wind and solar generation

Country	Source	Hourly profile	Total 2012 [TWh]
Wind			
Austria	APG webpage	Given	2.404
Belgium	ELIA webpage	Given	2.793
Czech Republic	CEPS webpage	Given	2.781
Germany	Amprion webpage	Given	45.86
	Tennet webpage		
	TransnetBW webpage		
	50Hertz webpage		
Spain	RED webpage	Given	61.352
France	RTE webpage	Given	14.907
Ireland	EirGrid webpage	Given	4.102
Italy	TERNA webpage	Given	16.156
Portugal	REN webpage	Given	10.029
United Kingdom	Gridwatch webpage	Given	12.616
Denmark	EnergiNetDK webpage	Given	10.265
Netherlands	ENTSO-E, monthly generation	Based on BE	4.998
Poland	ENTSO-E, monthly generation	Based on DE	4.381
Sweden	ENTSO-E, monthly generation	Based on DK	7.11
Switzerland	ENTSO-E, monthly generation	Based on AT	0.072
Norway	ENTSO-E, monthly generation	Based on DK	1.56
Finland	ENTSO-E, monthly generation	Based on DK	0.493
Solar			
Austria	ENTSO-E, monthly generation		0
Belgium	ENTSO-E, monthly generation	Based on FR	1.628
Czech Republic	CEPS webpage	Given	2.087
Germany	Amprion webpage	Given	27.887
	Tennet webpage		
	TransnetBW webpage		
	50Hertz webpage		
Spain	RED webpage	Given	11.615
France	RTE webpage	Given	3.782
Ireland	ENTSO-E, monthly generation		0
Italy	TSO website, hourly	Given	18.600
Portugal	TSO website, hourly	Given	0.327
United Kingdom	ENTSO-E, monthly generation		0
Denmark	ENTSO-E, monthly generation		0
Netherlands	ENTSO-E, monthly generation		0
Poland	ENTSO-E, monthly generation		0
Sweden	ENTSO-E, monthly generation		0
Switzerland	ENTSO-E, monthly generation		0
Norway	ENTSO-E, monthly generation		0
Finland	ENTSO-E, monthly generation		0

Appendix C: Equilibrium Conditions for Numerical General Equilibrium Model

We formulate the model as a system of nonlinear inequalities and characterize the economic equilibrium by two classes of conditions: zero profit and market clearance. Zero-profit conditions exhibit complementarity with respect to activity variables (quantities) and market clearance conditions exhibit complementarity with respect to price variables.[30] We use the $\perp$ operate to indicate complementarity between equilibrium conditions and variables. Model variables and parameters are defined in Tables C1, C2, and C3.

Zero-profit conditions for the model are given by:

$$\text{(C1)} \qquad c_r^C \geq PC_r \qquad \perp \quad C_r \geq 0 \qquad \forall r$$

$$\text{(C2)} \qquad c_{ir} \geq PY_{ir} \qquad \perp \quad Y_{ir} \geq 0 \qquad \forall i, r$$

$$\text{(C3)} \qquad c_r^G \geq PG_r \qquad \perp \quad G_r \geq 0 \qquad \forall r$$

$$\text{(C4)} \qquad c_r^I \geq PI_r \qquad \perp \quad I_r \geq 0 \qquad \forall r$$

$$\text{(C5)} \qquad c_{ir}^A \geq PA_{ir} \qquad \perp \quad A_{ir} \geq 0 \qquad \forall i, r$$

$$\text{(C6)} \qquad c_i^T \geq PT_i \qquad \perp \quad T_i \geq 0 \qquad \forall r$$

where c denotes a cost function. For electricity, i.e. $i = ELE$, equation is replaced by equation (10). According to the nesting structures shown in Figure C1b, the expenditure function for consumers is defined as:[31]

$$c_r^C := \left[\theta_r^{CON} (c_r^{CENE})^{1-\sigma^{ctop}} + \left(1 - \theta_r^{CON}\right) (c_r^{CCON})^{1-\sigma^{ctop}}\right]^{\frac{1}{1-\sigma^{ctop}}}$$

where

$$c_r^{CENE} := \left[\sum_{i \in cene} \theta_{ir}^{CENE} \left(\frac{PAE_{ir}}{\overline{pae}_{ir}}\right)^{1-\sigma^{cene}}\right]^{\frac{1}{1-\sigma^{cene}}}$$

$$c_r^{CCON} := \left[\sum_{i \in ccon} \theta_{ir}^{CON} \left(\frac{PAE_{ir}}{\overline{pae}_{ir}}\right)^{1-\sigma^{ccon}}\right]^{\frac{1}{1-\sigma^{ccon}}},$$

and where PAE_{ir} denotes the tax inclusive Armington prices defined as:[32] $PAE_{ir} := (1 + ti_{ir})\, PA_{ir}$.

Unit cost functions for production activities are given as:

$$c_{ir} := \left[\sum_{j \in mat} \theta_{jir}^{ytop} \left(\frac{PAE_{jr}}{\overline{pae}_{jr}}\right)^{1-\sigma^{top}} - \left(1 - \sum_{j \in mat} \theta_{jir}^{ytop}\right) (c_{ir}^{VAE})^{1-\sigma^{top}}\right]^{\frac{1}{1-\sigma^{top}}}$$

where

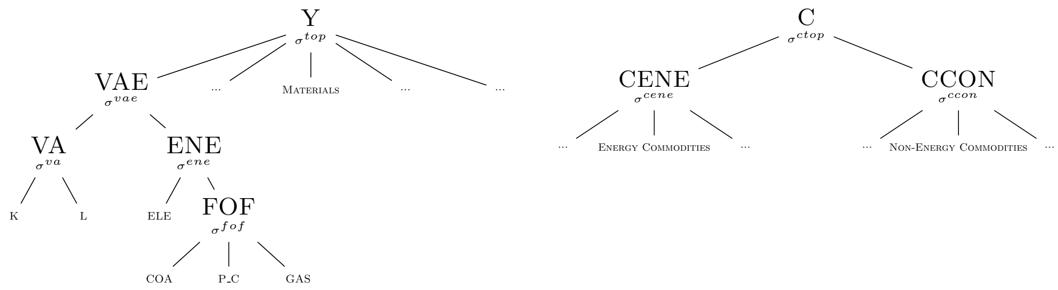
[30] A characteristic of many economic models is that they can be cast as a complementary problem, i.e. given a function $F\colon \mathbb{R}^n \longrightarrow \mathbb{R}^n$, find $z \in \mathbb{R}^n$ such that $F(z) \geq 0$, $z \geq 0$, and $z^T F(z) = 0$, or, in short-hand notation, $F(z) \geq 0 \perp z \geq 0$.

[31] Prices denoted with an upper bar generally refer to baseline prices observed in the benchmark equilibrium. θ generally refers to share parameters.

[32] We abstract here from cost for carbon which are added to the price and suppress for ease of notation the fact that taxes are differentiated by agent.

Figure C1. Nested Structure for Production and Consumption

(a) Production (b) Final Consumption



$$c_{ir}^{VAE} := \left[\theta_{ir}^{VAE} (c_{ir}^{VA})^{1-\sigma^{vae}} + \left(1-\theta_{ir}^{VAE}\right) (c_{ir}^{ENE})^{1-\sigma^{vae}}\right]^{\frac{1}{1-\sigma^{vae}}}$$

$$c_{ir}^{VA} := \left[\theta_{ir}^{VA} \left(\frac{(1+tl_{ir})PL_r}{\overline{pl_{ir}}}\right)^{1-\sigma^{va}} + \left(1-\theta_{ir}^{VA}\right) \left(\frac{(1+tk_{ir})PK_r}{\overline{pk_{ir}}}\right)^{1-\sigma^{va}}\right]^{\frac{1}{1-\sigma^{va}}}$$

$$c_{ir}^{ENE} := \left[\sum_{j\in ele} \theta_{jir}^{ENE} \left(\frac{PAE_{jr}}{\overline{pae_{jr}}}\right)^{1-\sigma^{ene}} + \left(1-\sum_{j\in ele}\theta_{jir}^{ENE}\right) (c^{FOF})^{1-\sigma^{ene}}\right]^{\frac{1}{1-\sigma^{ene}}}$$

$$c_{ir}^{FOF} := \left[\sum_{j\in fof} \theta_{jir}^{FOF} \left(\frac{PAE_{jr}}{\overline{pae_{jr}}}\right)^{1-\sigma^{fof}}\right]^{\frac{1}{1-\sigma^{fof}}} .$$

For government and investment consumption, fixed production shares are assumed:

$$c_r^G := \sum_i \theta_{ir}^G \frac{PAE_{ir}}{\overline{pae_{ir}}}$$

$$c_r^I := \sum_i \theta_{ir}^I \frac{PAE_{ir}}{\overline{pae_{ir}}} .$$

Trading commodity i from region r to region s requires the usage of transport margin j. Accordingly, the tax and transport margin inclusive import price for commodity i produced in region r and shipped to region s is given as: $PM_{irs} := (1+te_{ir})\,PY_{ir} + \phi_{jirs}^T PT_j$. te_{ir} is the export tax raised in region r and θ_{jirs}^T is the amount of commodity j needed to transport the commodity. The unit cost function for the Armington commodity is:

$$c_{ir}^{A} := \left[\theta_{ir}^{A} PY_{ir}^{1-\sigma^{dm}} + \left(1-\theta_{ir}^{A}\right) (c_{ir}^{M})^{1-\sigma^{dm}}\right]^{\frac{1}{1-\sigma^{dm}}}$$

where

$$c_{ir}^{M} := \left[\sum_s \theta_{is}^{M} \left((1+tm_{ir})\,\frac{PM_{is}}{\overline{pm_{is}}}\right)^{1-\sigma^{m}}\right]^{\frac{1}{1-\sigma^{m}}} .$$

International transport services are assumed to be produced with transport services from each region according to a Cobb-Douglas function:

$$c_i^T := \prod_s PY_{is}^{\theta_{is}^T}\,.$$

Denoting consumers' initial endowments of labor and capital as $\overline{L}_r$ and $\overline{K}_r$, respectively, and using Shephard's lemma, market clearing equations become:

$$\text{(C7)} \qquad Y_{ir} \geq \sum_s \frac{\partial c_{is}^A}{\partial PY_{ir}} A_{is} + \frac{\partial c_i^T}{\partial PY_{ir}} T_i \qquad \perp \quad PY_{ir} \geq 0 \qquad \forall i, r$$

$$\text{(C8)} \qquad A_{ir} \geq \sum_j \frac{\partial c_{jr}}{\partial PA_{ir}} Y_{jr} + \frac{\partial c_r^C}{\partial PA_{ir}} C_r + \frac{\partial c_r^G}{\partial PA_{ir}} G_r + \frac{\partial c_r^I}{\partial PA_{ir}} I_r \qquad \perp \quad PA_{ir} \geq 0 \qquad \forall i, r$$

$$\text{(C9)} \qquad \overline{L}_r \geq \sum_i \frac{\partial c_{ir}}{\partial PL_r} Y_{ir} \qquad \perp \quad PL_r \geq 0 \qquad \forall r$$

$$\text{(C10)} \qquad \overline{K}_r \geq \sum_i \frac{\partial c_{ir}}{\partial PK_r} Y_{ir} \qquad \perp \quad PK_r \geq 0 \qquad \forall r$$

$$\text{(C11)} \qquad T_i \geq \sum_{j,r} \frac{\partial c_{jr}^A}{\partial PT_i} A_{jr} \qquad \perp \quad PT_i \geq 0 \qquad \forall r$$

$$\text{(C12)} \qquad I_r \geq \bar{i}_r \qquad \perp \quad PI_r \geq 0 \qquad \forall r$$

$$\text{(C13)} \qquad C_r \geq \frac{INC_r^C}{PC_r} \qquad \perp \quad PC_r \geq 0 \qquad \forall r$$

$$\text{(C14)} \qquad G_r \geq \frac{INC_r^G}{PG_r} \qquad \perp \quad PG_r \geq 0 \qquad \forall r\,.$$

Private income is given as factor income net of investment expenditure and a lumpsum or direct tax payment to the local government. Public income is given as the sum of all tax revenues:

$$\text{(C15)} \qquad INC_r^C := PL_r \overline{L}_r + PK_r \overline{K}_r - PI_r \bar{i}_r - htax_r$$

$$\begin{aligned}\text{(C16)} \qquad INC_r^G := &\sum_i ti_{ir} PA_{ir} \left[\sum_j \frac{\partial c_{jr}}{\partial PA_{ir}} Y_{jr} + \frac{\partial c_r^C}{\partial PA_{ir}} C_r + \frac{\partial c_r^G}{\partial PA_{ir}} G_r + \frac{\partial c_r^I}{\partial PA_{ir}} I_r \right] \\ &+ \sum_i Y_{ir} \left[tl_r PL_r \frac{\partial c_{ir}}{\partial PL_r} + tk_r PK_r \frac{\partial c_{ir}}{\partial PK_r} \right] \\ &+ \sum_{i,s} \left[te_{ir} PY_{ir} \frac{\partial c_{is}^A}{\partial PY_{ir}} A_{is} + tm_{ir} \left(1 + te_{is}\right) PY_{is} \frac{\partial c_{ir}^A}{\partial PY_{is}} A_{ir} \right] \\ &+ htax_r\,.\end{aligned}$$

Table C1. Sets, and price and quantity variables

Symbol	Description
Sets	
$i \in I$	Commodities
$r \in R$	Regions
$ccon \subset I$	Non-energy consumption commodities
$cene \subset I$	Energy consumption commodities
$mat \subset I$	Material input commodities
$ele \subset I$	Electricity input commodities
Prices and quantities	
PA_{ir}	Armington price of commodity i in region r
PL_r	Wage rate in region r
PC_r	Consumer price index in region r
PG_r	Public consumption price index in region r
PI_r	Investment consumption price index in region r
G_r	Public consumption index in region r
C_r	Private consumption index in region r
A_{ir}	Armington index of commodity i in region r
INC_r^C	Private income in region r
INC_r^G	Public income in region r
I_r	Investment consumption index in region r
Y_{ir}	Production index sector i in region r
T_i	Production index international transport service i
PT_i	Price index international transport service i
PK_r	Capital rental rate in region r
PY_{ir}	Domestic commodity i output price in region r
PM_{irs}	Price of commodity i import produced in region r and shipped to region s
PAE_{ir}	Tax and carbon cost inclusive Armington price of commodity i in region r

Table C2. Model parameters

Symbol	Description
Elasticity of substitution parameters	
σ_r^{ctop}	Top level consumption (energy vs. non-energy consumption)
σ_r^{cene}	Final consumption energy commodities
σ_r^{ccon}	Final consumption non-energy commodities
σ_{ir}^{top}	Top level (material vs. value added/energy inputs) in sector i
σ_{ir}^{va}	Value added composite in production sector i
σ_{ir}^{vae}	Value added vs. energy composite in production sector i
σ_{ir}^{ene}	Energy composite in production sector i
σ_{ir}^{fof}	Fossil fuels in production sector i
σ_{ir}^{dm}	Domestic vs. imported commodity i
σ_{ir}^{m}	Imports of commodity i
Other parameters	
$\bar{i}_r$	Reference investment level
$htax_r$	Direct tax from household to local government
$\overline{pae_{ir}}$	Armington price inclusive of reference tax and carbon cost
$\overline{pl_{ir}}$	Tax-inclusive reference price for labor in production i
$\overline{pk_{ir}}$	Tax-inclusive reference price for capital in production i
$\overline{pm_{irs}}$	Tax-inclusive import price commodity i shipped to region s
tl_{ir}	Labor use tax in production i
tk_{ir}	Capital use tax in production i
ti_{ir}	Use tax for commodity i
te_{ir}	Export tax for commodity i
tm_{ir}	Import tax for commodity i
θ_r^{CON}	Expenditure share of energy commodities in total expenditure
θ_{ir}^{CENE}	Expenditure share of commodities i in total energy expenditure
θ_{ir}^{CON}	Expenditure share of commodities i in total non-energy expenditure
θ_{jir}^{ytop}	Share of commodity j in top-level production i
θ_{ir}^{VAE}	Share of value-added cost in value-added/energy cost bundle
θ_{ir}^{VA}	Share of labor cost value added cost bundle in production i
θ_{jir}^{ENE}	Share of commodity j cost in energy bundle in production i
θ_{jir}^{FOF}	Share of commodity j cost in fossil fuel bundle in production i
ϕ_{jirs}^{T}	Amount of commodity j needed to transport commodity i from r to s
θ_{ir}^{G}	Expenditure share commodity i public consumption
θ_{ir}^{I}	Expenditure share commodity i investment consumption

Table C3. Parameter values for substitution elasticities in production and consumption

Parameter	Description	Value
Production		
σ^{YTOP}	Materials vs. energy/value-added bundle	0.20
σ^{YMAT}	Materials	0.30
σ^{KLE}	Value-added vs. energy bundle	0.25
σ^{KL}	Capital vs. labor	0.30-1.50
σ^{ENE}	Primary energy vs. electricity	0.30
σ^{FOF}	Fossil fuels	0.80
Consumption		
σ^{top}	Energy vs. non-energy consumption	0.25
σ^{ene}	Energy commodities	0.40
σ^{oth}	Non-energy commodities	0.50

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