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2018 update

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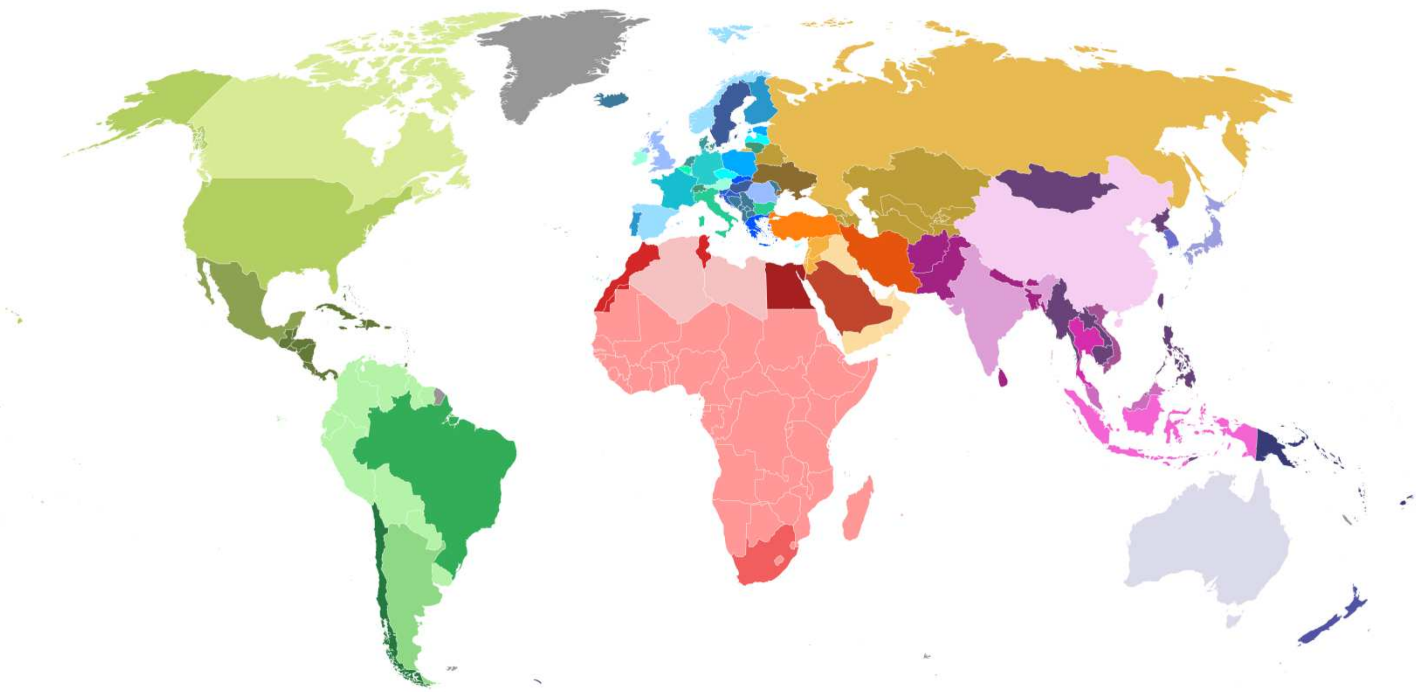

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Contents

Foreword

This document presents the Prospective Outlook on Long-term Energy Systems (POLES) model of the Joint Research Centre, as used in the 2018 edition of the Global Energy and Climate Outlook (GECO).

The model has been updated compared to the 2017 edition (Keramidas 2017), in particular in the building demand, power sector and the oil and gas sectors.

Acknowledgements

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Abstract

This report is a public manual for the POLES-JRC model, the European Commission in-house tool for global and long-term analysis of greenhouse gas (GHG) mitigation policies and evolution of energy markets. The model includes a comprehensive description of the energy system and related GHG emissions for a large set of significant economies and residual regions, covering the world and including international bunkers. Through linkage with specialised tools it also provides a full coverage of GHG emissions, including from land use and agriculture, as well as of air pollutant emissions.

The POLES-JRC model builds on years of development of the POLES model while adding specific features developed internally within the JRC.

The model version presented in this report is used in particular to produce the JRC Global Energy and Climate Outlook (GECO) edition of 2018.

Complementary information can be found on the following JRC Science Hub websites:

http://ec.europa.eu/jrc/poles
http://ec.europa.eu/jrc/geco

1 Introduction

The use of quantitative models of the energy sector in supporting policymaking has been increasing drastically in recent decades. The global partial equilibrium model POLES has a strong track record in providing analyses for the preparation of policy proposals in the area of climate change and energy. To this end, the model has continuously evolved so as to better match the needs of the policymakers.

The POLES (Prospective Outlook on Long-term Energy System) model has been used for more than two decades as an analytical tool for providing energy scenarios that inform the energy policy trade-offs for sustainable energy development at both world and EU levels. It was initially developed in the 1990s at the University of Grenoble (France) in the then IEPE laboratory ([1]) and was first funded under the JOULE II and JOULE III programmes of Directorate-General XII of the European Commission and under the Ecotech programme of the French CNRS. The model then was transferred to a simulation software by the Joint Research Centre (JRC).

Since then the model has been improved and extended on several occasions to capture the most recent market and policy developments. Modelling upgrades include final energy demand, electricity production, the role of hydrogen as an energy vector, the oil, gas and coal international markets and GHG emission projections.

Its features and the extensive range of results produced have been used to support a number of studies on energy prospects and on GHG emission mitigation policies for various European, international and national institutions over the last 20 years.

The JRC has co-developed the model for some time and recently issued the POLES-JRC version.

This report documents the latest version of the POLES-JRC model as of early 2017, which shares elements with other versions of the POLES model used by other institutions ([2]). Following a general description of the model and the economic activity, it details the approach implemented in the various end-use and supply sectors. Considering the application of the model in assessing global GHG emission scenarios, specific sections address the calculation of emissions and of scenario building. This version is used for the JRC Global Energy and Climate Outlook series (GECO) ([3]).

([1]) Now part of the GAEL laboratory: https://gael.univ-grenoble-alpes.fr/?language=en
([2]) GAEL (French research laboratory) https://gael.univ-grenoble-alpes.fr/research-areas/energy-axis?language=en; Enerdata https://www.enerdata.net/
([3]) www.ec.europa.eu/jrc/geco, see GECO 2016 (Kitous et al. 2016).

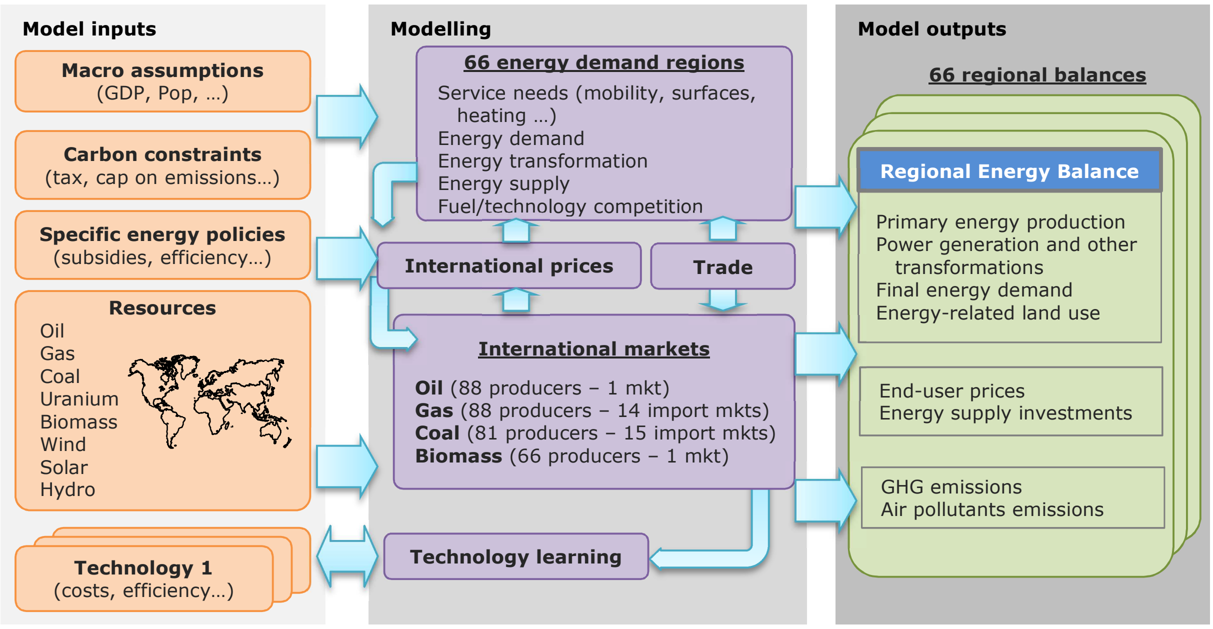
2 General description

This section gives an overview of the model in terms of scope and objectives, modelling principles and geographical breakdown.

The POLES-JRC is a simulation model designed for energy and climate policy analysis. Its main features are the following:

- full description of the energy sector:
    - demand and supply linked through prices,
    - detailed representation of end-use sectors, power generation and other transformation sectors and primary supply,
    - disaggregation to all types of energy fuels,
    - explicit technology dynamics,
    - historically calibrated behaviour of economic agents;
- energy and non-energy related emissions of GHGs and air pollutants;
- a global coverage while keeping regional detail;
- updated information (historical data up to current year – 1);
- an annual time step and typical projection horizon until 2050.

Figure 1. Schematic representation of the POLES-JRC model architecture



2.1 Scope and objective

The POLES-JRC model is a simulation model for the development of long-term energy supply and demand scenarios, including related emissions, for the different regions of the world. It simulates technology dynamics and follows the discrete choice modelling paradigm in the decision-making process. It determines market shares (portfolio approach) of competing options (technologies, fuels) based on their relative cost and performance while also capturing non-cost elements like preferences or policy choices.

POLES-JRC covers the entire energy sector, from production to trade, transformation and final use for a wide range of fuels and sectors. In addition, non-energy greenhouse gases as well as air pollutants are covered, be they associated with the energy sector or with other economic activities ([4]).

The model's scope is global, with an explicit representation of 66 geographical entities (see Section 2.3).

The POLES-JRC model runs in annual time steps, with the model's outlooks typically extending from 1990 to 2050, the time horizon for which the technological representation is most relevant; for very long-term climate mitigation assessments the model can be run to 2100.

The model is conceived for the purpose of providing analytical support on the following:

- Assessment of policies related to the energy sector

The model is used to quantify the impact of policies on the evolution of the energy sector compared to its evolution without that intervention or with an alternative policy formulation. This is achieved through the comparison of scenarios concerning possible future developments of world energy consumption and corresponding GHG emissions under different assumed policy frameworks. Policies that can be assessed include: energy efficiency, support to renewables, energy taxation/subsidy, technology push or prohibition, access to energy resources, etc.

- Greenhouse gas emissions abatement strategies

The model can assist the formulation of GHG emissions reduction strategies in a national or international perspective. The high sectoral and technological detail of the model can help in identifying and prioritising strategic areas of action for mitigation through the comparative analysis of multiple reduction scenario pathways in terms of emissions and costs. Additionally, it can be used to assess the costs of compliance with global, national and sectoral emission targets.

Finally, the model allows assessment of the impact of energy and climate policies on air pollutants ([5]) (see Section 6.2).

- Technology dynamics

The model can assess the market uptake and development of various new and established energy technologies as a function of changing scenario conditions. The key parameters characterising the costs and performances as well as the diffusion process of these technologies are incorporated in the model for power generation, hydrogen production, vehicles and buildings.

The global coverage allows an adequate capture of the learning effects that usually occur in global markets. In particular the modelling of power production technologies is associated with dynamic technology learning.

- International fuel markets and price feedback

The model can provide insights into the evolution of the global primary energy markets and the related international and regional fuel prices under different scenario assumptions. To this end, it includes a detailed representation of the costs in primary energy supply (in particular oil, gas and coal supply), for both conventional and unconventional resources. At the same time, the (regional) demand for the various fuels is simulated and matched through price adjustments.

The model can therefore be used to analyse the impacts of energy and climate policies and energy taxation/subsidy phase-in/out on the international energy markets. The

([4]) The model provides a full coverage of GHG emissions: detailed emissions from the energy sector and industrial processes are derived directly from the core modelling, while emissions from agricultural activities and LULUCF (land use, land use change and forestry) are derived from a linkage with the GLOBIOM model (IIASA 2016a) (see Section 6.1.5).

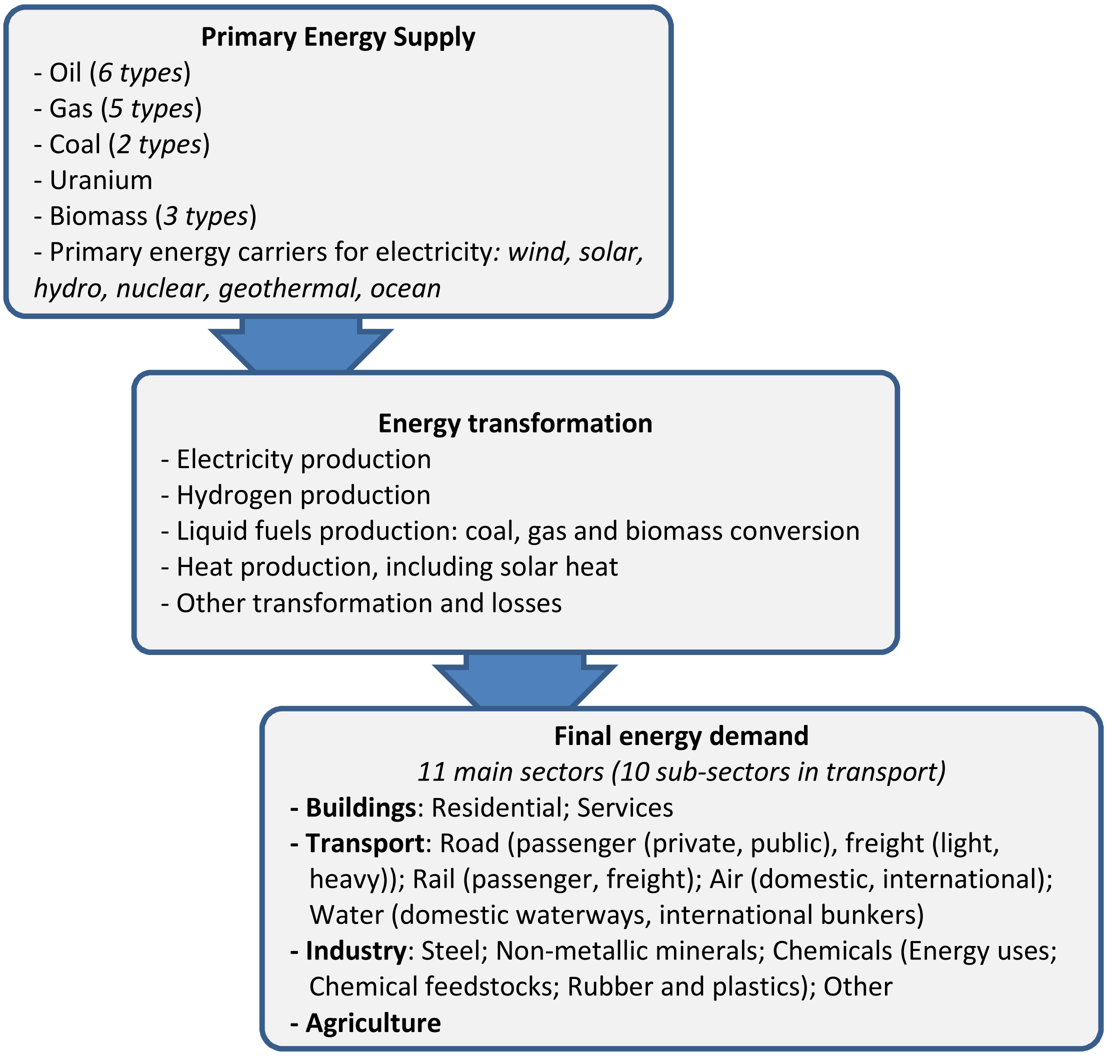
([5]) Through a linkage with the GAINS model (IIASA 2016b) interaction of regions and energy fuels allows for the study of the effects of policies on producers' revenues, of the price feedback on consumers or of carbon leakage.

2.2 Modelling principles and methodology

2.2.1 Model structure

POLES-JRC is a partial equilibrium model of the energy system (i.e. without feedback on the economic system) using recursive simulation.

Figure 2. Schematic representation of the POLES-JRC sectors



Energy demand by region and sector is derived from socioeconomic developments (exogenous assumptions), policy conditions and the evolution of international energy prices. It is met by the operation of the installed equipment, be it transformed or primary energy. Simultaneously the model identifies expected future energy needs and determines the required capacity to cover these needs, accounting for the decommissioning or underutilisation of existing equipment.

Primary energy consumption by region is given by the aggregated sectors' final energy demand and energy used in transformation. It is supplied by domestic energy production via international markets. The comparison of demand dynamics and export capacities for each market establishes the market equilibrium and the determination of the price for the following period, which impacts future demand and supply with lagged variables.

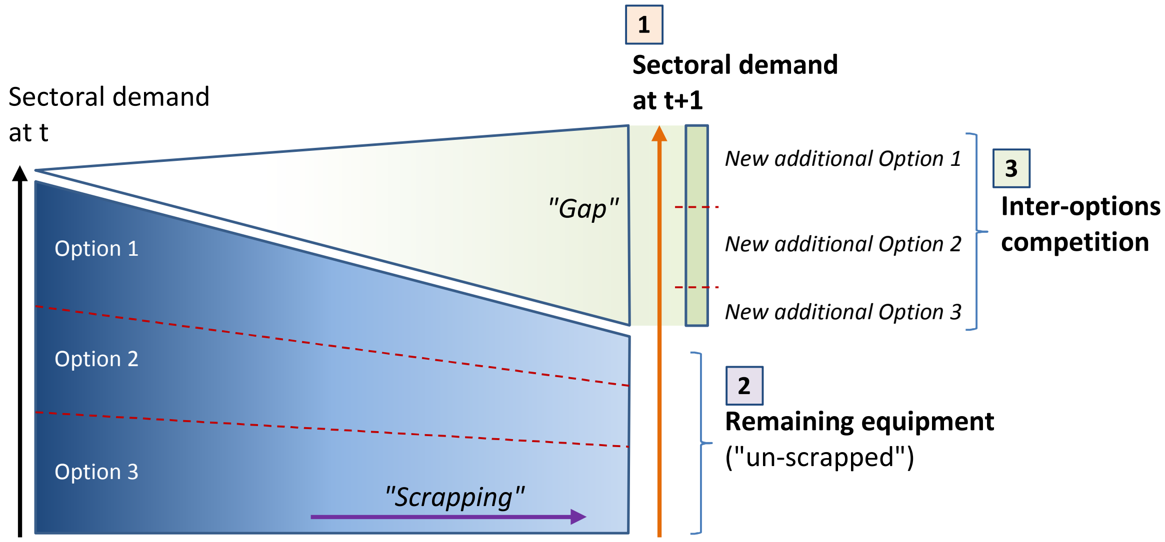
For each region, the model represents three main modules, themselves with several sub-modules, as described in the **Figure 2**. This structure allows for the simulation of an energy balance for each region.

2.2.2 New equipment and competition across options

The model makes use of a common modelling approach across sectors in order to represent the need for new energy equipment and the competition across options:

1. The evolution of the total stock (or capacity) is set by activity drivers, energy prices and technological development;
2. The installed equipment can meet part of the total demand, once depreciation (scrapping) has been taken into account;
3. The remaining needs after contribution of the un-scrapped equipment is covered by a competition between options (fuels or technologies).

Figure 3. Schematic representation of the energy needs and depreciation procedure in POLES-JRC



1. The *standard demand equation* follows the general form:

$$\boldsymbol{Demand} = \boldsymbol{Activity}^{\boldsymbol{ey}} \times \boldsymbol{f}[(\boldsymbol{Avg.Price})^{-\boldsymbol{es}}] \times \boldsymbol{f}[(\boldsymbol{Avg.Price})^{-\boldsymbol{el}}] \times \boldsymbol{Trend}$$

It combines:

- an income or activity effect, through an activity elasticity (ey): the activity variables are sector-specific: income per capita, sectoral value added, household surfaces etc;
- price effects: the structure of the equations allows for taking into account both short-term (es) and long-term (el) price elasticities, with a distributed lag structure over time and possible asymmetries between the increasing or decreasing price effect;
- an autonomous technological trend that reflects non-price-dependent evolution of the equipment performance, due to purely technological advancements or to non-price policies (e.g. efficiency standards);
- the fact that the activity elasticity and the trend can be dynamic so as to capture saturation effects.

2. Installed equipment is determined by a survival law that considers the general dynamics of total demand, the average lifetime of the equipment and the evolution of the relative cost of use of the option compared to others.

3. In order to take into account the flexibilities and rigidities introduced by existing capital stocks, the competition between options takes place only in the space created between the total needs and the un-scrapped equipment: a 'gap' to be filled by new equipment ('putty-clay' demand function).

Fuel or technology market shares are calculated in a cost-based competition process using a discrete choice formulation.

It takes into account:

- the user cost of the different options (C_i), which includes the investment cost, the lifetime, a time discounting factor (6), the fuel utilisation efficiency and the fuel price;
- a weighting factor to capture the observed deviation from pure cost-based competition (a_i), calibrated on historical market shares and reflecting non-economic preferences; it can evolve exogenously over the simulation to capture infrastructure developments, technology choices, etc.

$$\boldsymbol{Market\ share}_{\boldsymbol{option\ i}} = \frac{\boldsymbol{a_i} \times \boldsymbol{C_i}^{-\boldsymbol{e}}}{\sum_i \boldsymbol{a_i} \times \boldsymbol{C_i}^{-\boldsymbol{e}}}$$

The total demand by option is then the sum of remaining demand after depreciation and of the new demand.

This formulation is found in the final demand sectors and in fossil fuel supply.

The planning of power capacities follows a similar logic, except that the competition takes place over the entire expected demand looking 10 years ahead. This expected demand takes into account investors' expectations on the evolution of the policy framework, as well as fuel prices; expectations are based on extrapolations of historical trends, and therefore do not constitute a perfect foresight. Since the capacity planning in power generation is of a recursive nature, investment decisions taken in year t can be modified in year t + 1 except for those installations for which construction was assumed to have started already (a tenth of the total).

2.2.3 Energy technology dynamics

The concept of technology learning (7) links the improvements in performance, productivity and/or cost of a technology to the accumulation of experience. Instead of trying to disentangle the technology cost reductions to multiple items, the model uses the 'One-factor-learning-curve' (8) approach that links the unit cost development of a technology to the evolution of the accumulated production of that technology.

Due to the global nature of the power equipment market, learning is assumed to take place as a function of the worldwide installed capacity of a certain technology (in W). Depending on the scenario settings, which affect the deployment of a given technology, different trajectories of the technology costs can be derived.

(6) The time discounting factor used for investment decisions includes a discount rate and a sector-specific risk preference factor.
(7) See for example Wright (1936).
(8) The literature identifies more complex formulations, which include for instance learning by researching, learning by using, learning by scaling and learning by copying (i.e. knowledge spillovers) (Sagar and van der Zwaan, 2006). The 'learning by searching' in particular (linked to R & D expenditures) has been explored with the POLES model — see the SAPIENT, SAPIENTIA and CASCADE MINTS projects. However Wiesenthal et al. (2012) show that lack of historical data and robust projections of the associated drivers make them difficult to handle.

$$C_t = Q_t^{ln(1-LR_t)/ln(2)}$$

with C = Costs of unit production (€/W)

Q = Cumulative Production (W)

LR = Learning rate

t = Technology

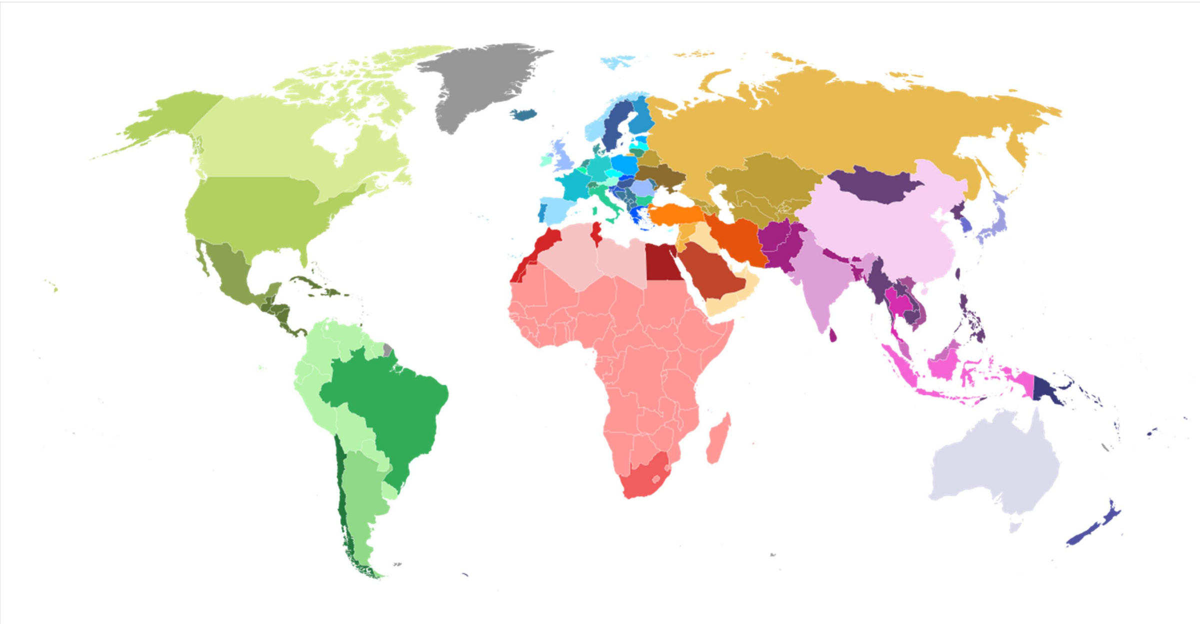
Learning rates (LR) correspond to the percentage decrease of investment cost of a technology when the installed cumulated capacity of the technology doubles.

For Carbon Capture and Storage (CCS) plants, different learning applies to the power production facility on the one hand and to the carbon capture component on the other hand. Similarly, in concentrated solar power plants, the investment cost of storage is separated from the learning in the rest of the plant.

2.3 Geographical breakdown

The world energy consumption is decomposed into 66 *geographical entities (*see **Figure 4***)*: the EU-28, 26 large economies (including detailed OECD countries, G20 and emerging Asian countries) and 12 country aggregates. International bunkers (air and maritime) are also taken into account.

Figure 4. POLES-JRC geographic breakdown



The geographical decompositions for oil, gas and coal production are different, in order to represent resource-rich countries in greater detail, with more than 80 individual producers. Mappings are provided in Annex 2: Country mappings.

2.4 Main activity drivers

Population and economic activity expressed as GDP (gross domestic product) — together with a sectoral decomposition of the value added — are direct inputs to the model driving the evolution of sectoral energy-consuming activity variables. The main information sources used are (see also Section 8 on data):

- for the EU: the Ageing Report (European Commission 2015);

- for non-EU regions: UN for population (UN 2015), IMF and OECD for economic growth (respectively IMF 2016 and OECD 2014).

The evolution of other socioeconomic variables like housing needs (number, size) and mobility (both passengers and freight) is also derived from the inputs on population and growth of GDP per capita

Economic variables are expressed in real monetary terms (constant US dollars). Data on GDP and sectoral value added are expressed in purchasing power parity.

3 Final energy demand

Final energy demand in the model is dealt with explicitly for four sectors: industry, residential and services, transport and agriculture. This chapter describes for each of them the related activity drivers and resulting energy needs. In addition, one section is dedicated to the formulation of energy prices, which play an important role in the dynamics of energy demand.

3.1 Industry

3.1.1 Disaggregation and general approach

Industry is disaggregated into different manufacturing sectors and mining and construction ([9]). In line with the IEA/Eurostat balances, industrial energy consumption does not include transport used by industry (which is reported under transport); it also excludes the fuel input for auto-production but includes the auto-produced electricity.

Final energy demand in industry is divided into four energy sectors:

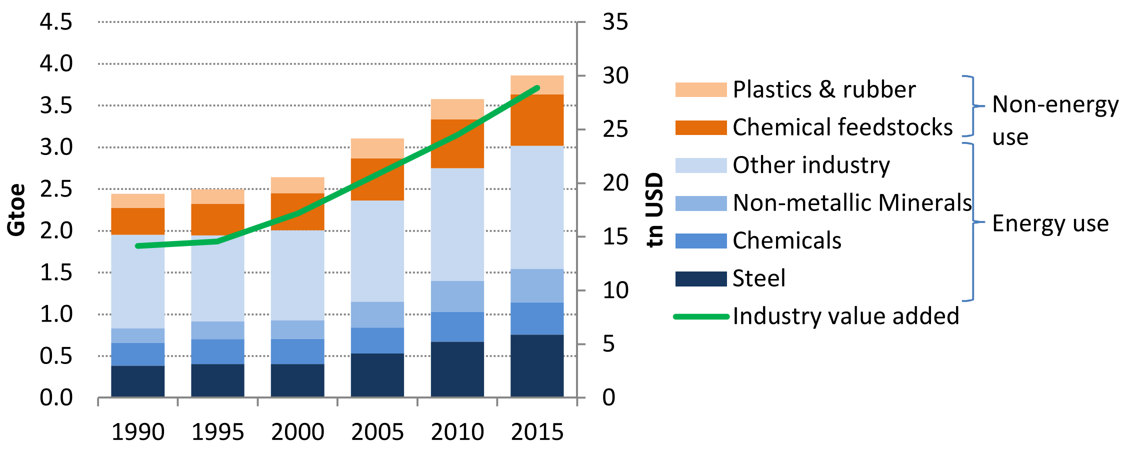
- iron and steel;
- chemicals;
- non-metallic minerals (NMM): cement, lime, glass, ceramics and other NMM;
- other industry: other manufacturing, mining and construction.

The industrial sectors that are modelled individually were chosen because of their energy-intensive processes; they represented approximately 50 % of the energy consumption ([10]) of industry at world level in 2010.

Additionally, the consumption of fuels for non-energy uses is captured for two types of products: chemical fertilisers and plastics and rubber.

Figure 5 shows the evolution of total input fuels (both for energy uses and non-energy-use) and industry value added since 1990. The sector undertook a decoupling with total value added more than doubling while fuel inputs increased only by 60 % over the period.

Figure 5. World consumption of industry per sector (left) and industry value added (right)



Source: IEA 2017a, Enerdata 2017a

([9]) The energy transformation industry (transformation of energy fuels, including the power sector) is treated separately from the industry that is a *final energy consumer*.
([10]) Energy uses only, see Enerdata (2015a)

3.1.2 Steel sector

3.1.2.1 Steel activity

The activity indicator for the steel industry is the tonnes of steel produced.

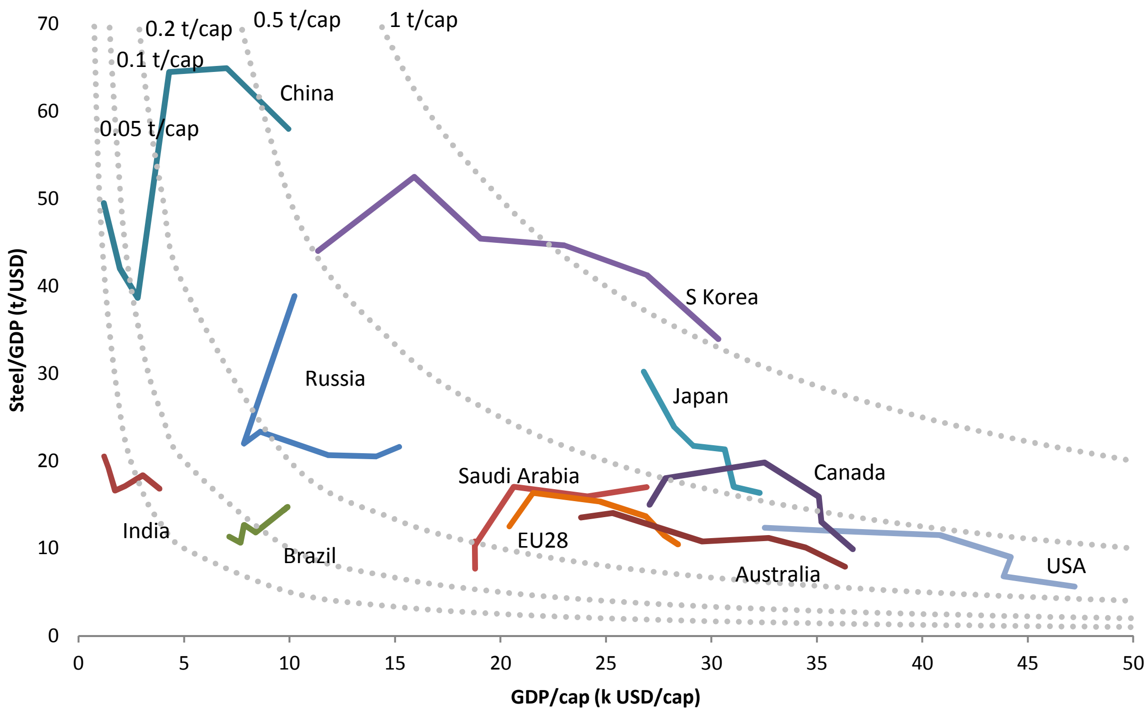
Regional steel demand is modelled using the concept of intensity of use (van Vuuren et al. 1999; Hidalgo et al. 2003): consumption per unit of GDP first increases through a rapid equipment phase and industrialisation, then peaks and goes through an extended decreasing phase as the economy shifts to services. It is modelled with the following equation:

$$\frac{\boldsymbol{Cons}}{\boldsymbol{GDP}} = \boldsymbol{f}\left(\frac{\mathbf{1}}{\frac{\boldsymbol{GDP}}{\boldsymbol{Pop}}}\right), \boldsymbol{f}\left(\frac{\boldsymbol{GDP}}{\boldsymbol{Pop}}\right), \boldsymbol{Floor}$$

This behaviour is calibrated for each world region (see **Figure 6**).

The model evaluates the stock of steel in the economy and the amount of scrap available each year, considering obsolescence factors in the different sectors consuming steel.

Figure 6. Apparent steel consumption per unit of GDP versus income per capita for select G20 countries, 1990-2015



Source: WSA 2015

NB: Russia's high point in steel/GDP corresponds to 1992 figure. GDP is in USD 2005 PPP.

The model differentiates between secondary steel (electric arc furnaces), which depends on the amount of scrap available (estimated from the stock of steel and average lifetime of use in the different sectors), and primary steel (from thermal processes) that makes the difference from total steel production needs.

After consideration of the decommissioning of existing capacities, the additional production capacities — distinguished between electric arc and integrated steel production — are allocated across all regions with a competition based on pre-existing capacities, evolution of local steel consumption and steel production cost (energy cost and a fixed infrastructure cost).

3.1.2.2 Steel industry energy demand

The consumption of each fuel is distributed between thermal processes and electric processes considering tonnes produced by process, theoretical energy needs per tonne and fuel conversion efficiency in the case of auto-production of electricity. Coking coal and marketed heat are always assigned to thermal processes.

In each of the two processes, total demand for non-electric fuels in competition and electricity follows a standard demand equation, determined by the evolution of the tonnes of steel and the energy price. Within non-electric fuels in competition (oil, gas, coal and biomass), the fuel substitution processes and the equipment lifetime are similar to those in the other industrial sectors.

Coking coal in thermal processes follows its own standard demand equation, influenced by the price of coking coal. Blast furnace gas produced during the combustion of coke and used as a fuel input in steel processing is also calculated based on coke consumption. This is taken into account in the emissions from the sector (see 6.1.2 Energy-related emissions).

3.1.3 Other industrial sectors

This section applies to the three non-steel industrial sectors: chemistry, non-metallic minerals and other industry. In each case the activity indicator is the sector's value added.

For each sector, total demand for process heat is calculated with a standard demand equation, influenced by the sector's value added and the average price of the fuels in competition. Within that total, a cost-based competition takes place between oil, gas, coal and biomass. For each fuel, costs include fixed infrastructure costs, a fuel utilisation efficiency and fuel-specific weighting factors reflecting the initial historical distribution of fuel demand and evolving towards cost-only competition.

Demand for electricity is calculated separately, with a standard demand equation.

3.1.4 Non-energy uses of fuels

Two economic activities using fuels as raw material are differentiated:

- chemical fertilisers that can consume oil, gas and coal;
- plastics and rubber that can consume oil and biomass.

The activity indicator is the chemical industry value added.

Related process and end-use CO_2 emissions are covered.

3.2 Residential and services

The residential sector and the services sector share a number of common features, since these activities are mostly related to buildings. Their energy consumption is modelled per end-use. The energy demand in each end-use is based on observed correlations between energy consumption data and specific activity variables or potential driving indicators (number and surface of residential dwellings, surface of service buildings, services sectoral value added), GDP, energy prices and technology costs (insulation, heaters and boilers). When relevant, climate indicators (degree days) are also used to account for the effects of climate change on the residential and service sector.

The calibration work is made difficult by the low consistency of data, due to differences in reporting, methodologies and country specificities ([11]). The modelling methodology is briefly described below.

3.2.1 Space heating

The space heating energy consumption is based on building surfaces, impacted by the evolution of population, number of people per household and surface per dwelling. For services it is driven by the share of the population working in the service sector.

Residential space heating is computed based on the total heating comfort, which indicates what useful energy a house with no insulation at all will consume, or how much insulation comfort is needed for a house to be passive (not requiring any useful heating consumption). It is either achieved through insulation comfort or useful energy consumption:

$$Total\ heating\ comfort = Insulation\ comfort + Useful\ energy\ consumption$$

The **total heating comfort** needs is shown to depend on the Heating Degree Days (HDD). HDD is an indicator based on the summation of the difference between external temperatures and a reference temperature ([12]); they reflect the energy needed to heat a building.

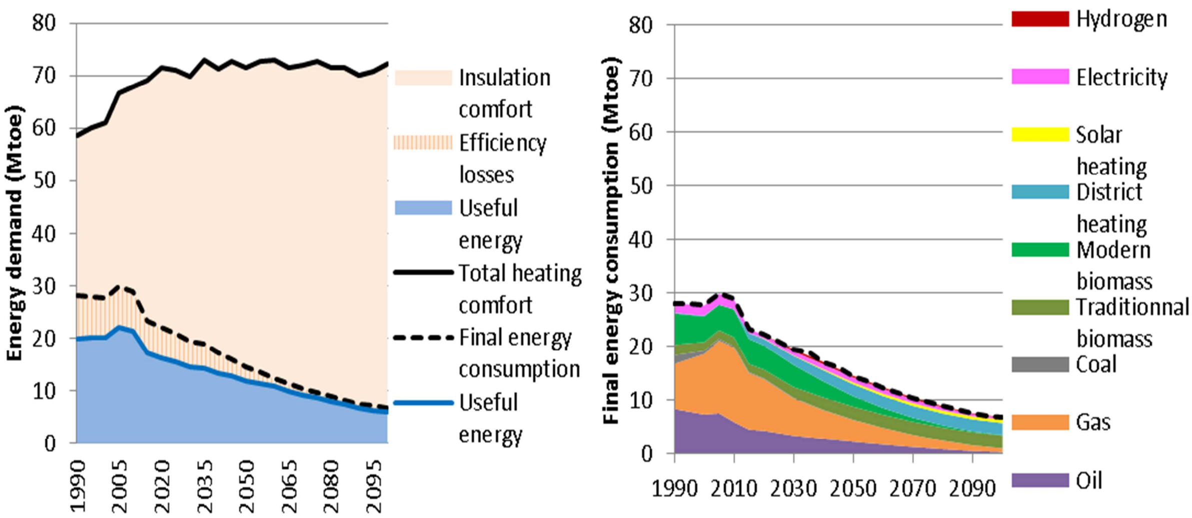
$$Total\ heating\ comfort\ per\ surface = 0.005 * HDD^{1.4} \qquad (in\ kWh/m^2)$$

The **insulation comfort** is calculated from the U-value (in W/m2/K), which defines the insulation of each component of a building assuming a standard building envelope *and* approximating the temperature difference between inside and outside. The insulation comfort diffuses across the building stock depending on the new demand and renovation of building surfaces. The insulation comfort of new buildings is assumed to be more ambitious than renovated buildings (easier works).

Useful energy consumption is the result of energy consumed multiplied by its efficiency.

An illustration of the decomposition of the total heating comfort is shown in **Figure 7**.

Figure 7. Decomposition of the final energy consumption for space heating, for France in the reference scenarios, decomposition of the total heating needs (left) and by fuel demand (right)



Source: GECO 2018 (Keramidas 2018).

([11]) The calibration in the residential and service sectors is based on available data from the IDEES (Mantzos 2018) and ODYSSEE database together with some estimates of end-use decomposition by Enerdata.
([12]) The reference temperature for computing HDD is 18°C.

Space heating in service buildings follows the same building codes and trends than the residential buildings (based on the residential heating comfort, insulation and U-value), but are also impacted by their own evolution of surfaces.

The evolution of useful energy needs (and therefore, final energy consumption) takes into account the retirement of obsolete equipment and new needs. Coal, traditional biomass and district heat are represented separately, following exogenous trends calibrated on historical data and fuel-specific constraints:

- Coal is sensitive to the carbon price and its trend decreases progressively between 2020 and 2050;
- traditional biomass is sensitive to the biomass potential.

Low temperature solar heat is also separated, based on its return on investment and constrained by its potential.

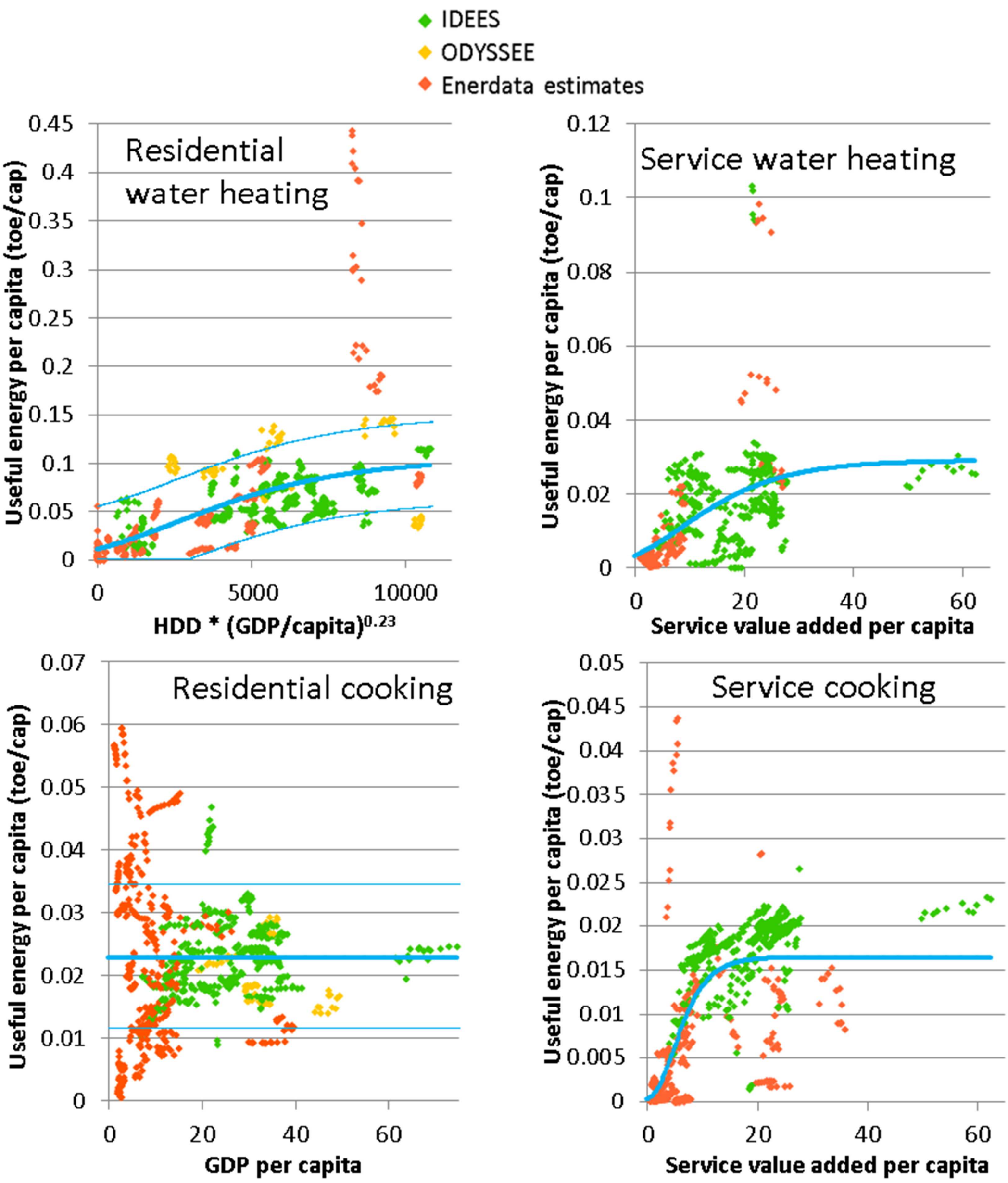
The remaining needs for new heating equipment are split between oil, gaseous fuels (natural gas and hydrogen), electricity (resistive heating and heat pump) and modern biomass as follows:

- If there is no need for further heating equipment, each energy source is shrunk proportionately to its importance.
- Otherwise, the choice of fuels is based on a competition between fuels based on fuel efficiency and costs, installation costs and infrastructure cost, combined with a historically calibrated factor, to cover for elements going beyond the purely cost-based modelling, such as consumer preferences.

3.2.2 Water heating and cooking

The water heating and cooking energy consumption are calibrated and expressed as functions of population, HDD, GDP (for residential buildings) and service value added (for service buildings), as shown in **Figure 8** (the corresponding equations are detailed in annex 3).

Figure 8. Water heating (top) and cooking (bottom) useful energy per capita, in residential (left) and service (right) buildings.



Source: based on IDEES, ODYSSEE and some estimates by Enerdata, 2000 – 2010.

The main outlying data are countries with a relatively low reliability, and usually show a trend of converging towards the identified formula. For both water heating and cooking in the residential sector, the countries with the highest difference with the rest of data sources are corrected and brought to a range around the formula, defined by the standard deviation of all available data. For the few countries without historical data, the formulas are used.

The new useful energy needs is obtained by following the same absolute variation as the formula. There is a ceiling (level of the formula for 80 k$/cap of GDP/cap for residential or 80 k$/cap of service value added for services).

The need for new energy installations per fuel is calculated as with space heating. Coal, traditional biomass and heat follow their dynamic, while oil, gas and hydrogen, modern biomass and electricity are in competition for filling the gap created by the updated consumption and the remaining non-decommissioned equipment.

3.2.3 Space cooling

The factors impacting space cooling are Cooling Degree Days (CDD) ([13]), electricity prices and economic development (GDP for the residential sector, service value added for the service sector).

The consumption of space cooling in the residential sector is decomposed in two factors: the Air Conditioning (AC) equipment rate of households (itself decomposed into maximum penetration potential and actual equipment saturation) and the consumption per equipped household.

The maximum penetration is calibrated on existing data.

The actual level of saturation is dependent on the starting point and on time.

$$Saturation_{AC,Time} = \frac{Equipped households}{Maximum\ penetration_{AC}}$$

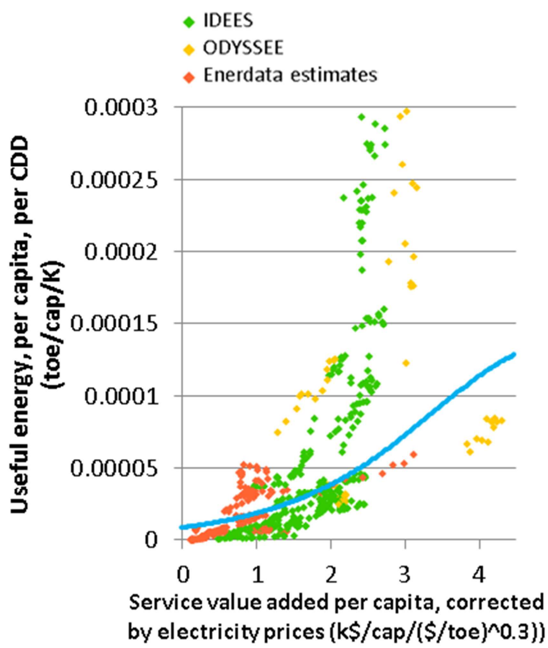
The energy consumption of a single equipped household is assumed to be dependent on the climate (CDD) but also on the proportion of the household expenditures dedicated to space cooling: the budgetary coefficient.

$$Budgetary\ coefficient\ of\ space\ cooling\ useful\ energy\ of\ equipped\ households = \frac{Space\ cooling\ electricity\ consumption}{Equipped\ dwelling * efficiency} * \frac{electricity\ price}{GDP}$$

This coefficient follows its historical trend of evolution at the beginning of the scenario, but then converges towards the formula.

The space cooling energy used in services is linked to value added of services, CDD and to a price effect, as shown in **Figure 9** (see also annex 3 for full equations).

Figure 9. Service space cooling, with suggested formula.



Source: based on IDEES, ODYSSEE and some estimates by Enerdata, 2000 – 2010. Countries with CDD under 150 were excluded.

The useful energy used in services for space cooling evolves with the same absolute variations as the formula (therefore reacting to changes in CDD, population, service

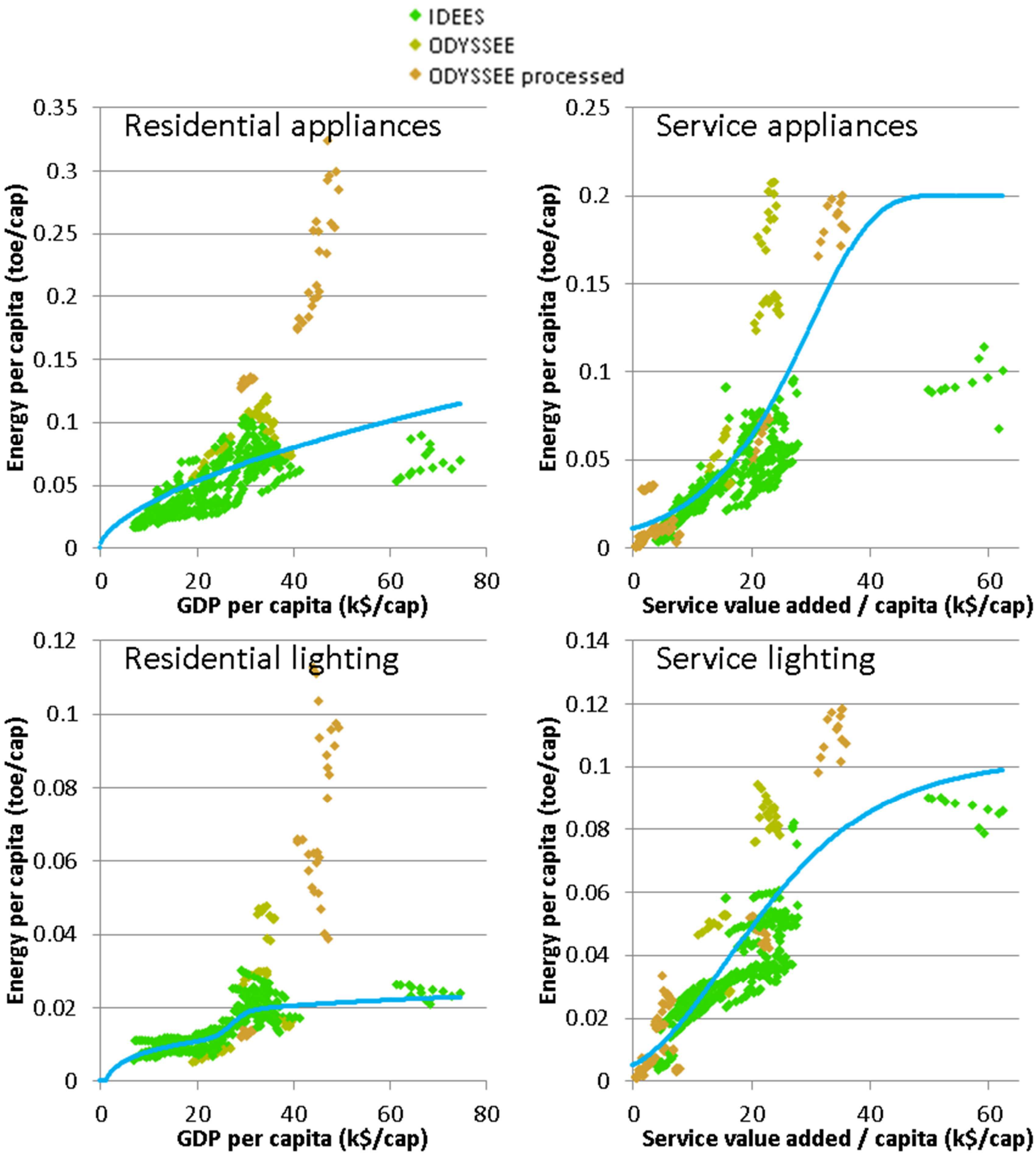
([13]) The reference temperature for computing CDD is 18°C.

value added and electricity prices). There is also a ceiling of the effect of service value added (80k$/cap, like in service water heating and cooking).

3.2.4 Appliances and lighting

Based on IDEES and ODYSSEE databases, appliances and lighting can be linked to wealth (GDP per capita for residential sector, service value added for services). The suggested formulas are chosen to fit better the IDEES and ODYSSEE data points (see **Figure 10** and annex 3 for the corresponding equations).

Figure 10. Appliances (top) and lighting (bottom) energy consumption per capita in residential (left) and service (right) sectors



Source: based on IDEES and ODYSSEE data and (Fleischmann, 2015), 2000 - 2014.

The evolution in time of the per-capita consumption of appliances and lighting shows additional characteristics. Countries with low per-capita revenues are picking up on richer countries in terms of modern appliances (television, mobile phones, refrigerators, etc.). Therefore this additional component is added on top of the formula for appliances.

For lighting, the overall trend is negative but no specific driver was found, with a general improvement of efficiency across all countries.

There is also a price effect (elasticities of -0.33 for appliances and -0.7 for lighting) and an additional impact of carbon policies for appliances, which represent improved energy regulation of appliances. The trajectories of per-capita consumption of all countries and regions are influenced by the historical starting point and historical trend.

As a result of this modelling, a developing country will see a measurable increase in consumption as the GDP increases, but will then stabilise or decrease.

3.3 Transport

POLES-JRC projects vehicle stocks per engine type, related energy use and GHG emissions. It allows a comparison of energy consumption and emissions across all modes and regions for different scenarios.

Transport energy demand satisfies the needs of passenger mobility and freight. In road transport, the modelling includes a detailed representation of the vehicle stock and propulsion technologies; in rail, air and water transport energy demand is directly related to the activity indicators.

3.3.1 Mobility

3.3.1.1 Passengers

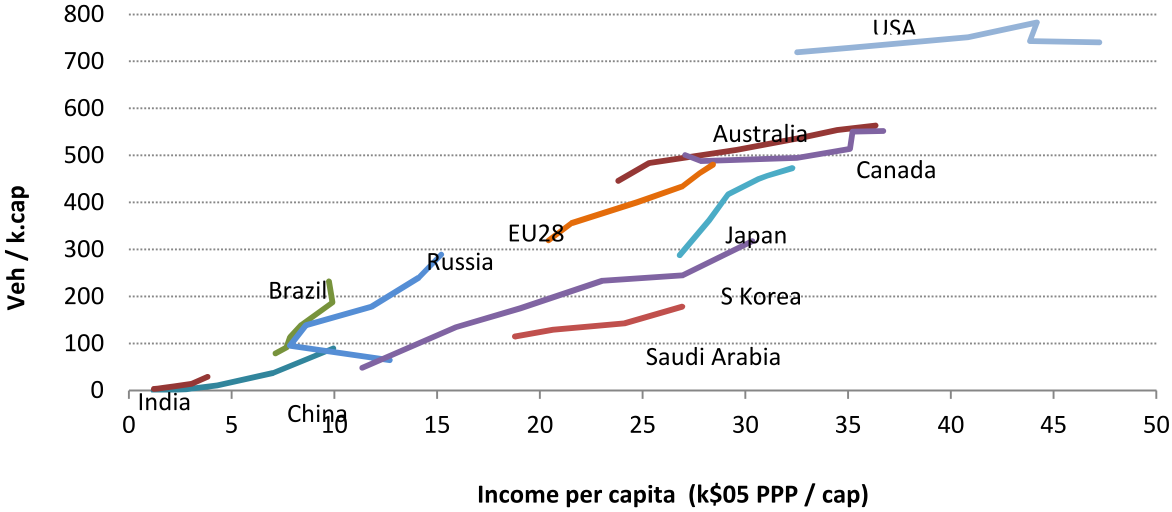
Passenger mobility is expressed in passenger-kilometres and takes place on land (road, rail) and by air. It is driven by income and energy prices in the different modes, with partial substitution taking place across modes: private means (cars, motorcycles) or public means (buses, rail, air).

For private means, the vehicles are modelled explicitly, with a vehicle stock and new annual sales. The total mobility is the product of the vehicle stock and the average mileage per vehicle.

The vehicle stock is defined by a per capita equipment rate, influenced by income and capped by a saturation level; for motorcycles, the equipment rate decreases with the income per capita.

The average mileage per vehicle is driven by the equipment rate (more vehicles translates into lower usage per vehicle) and average fuel price (decrease of use with higher prices). Motorcycles are bundled with private cars by translating their mobility into a ‘car equivalent’.

Figure 11. Equipment rate vs. income per capita for select G20 countries, 1990-2015



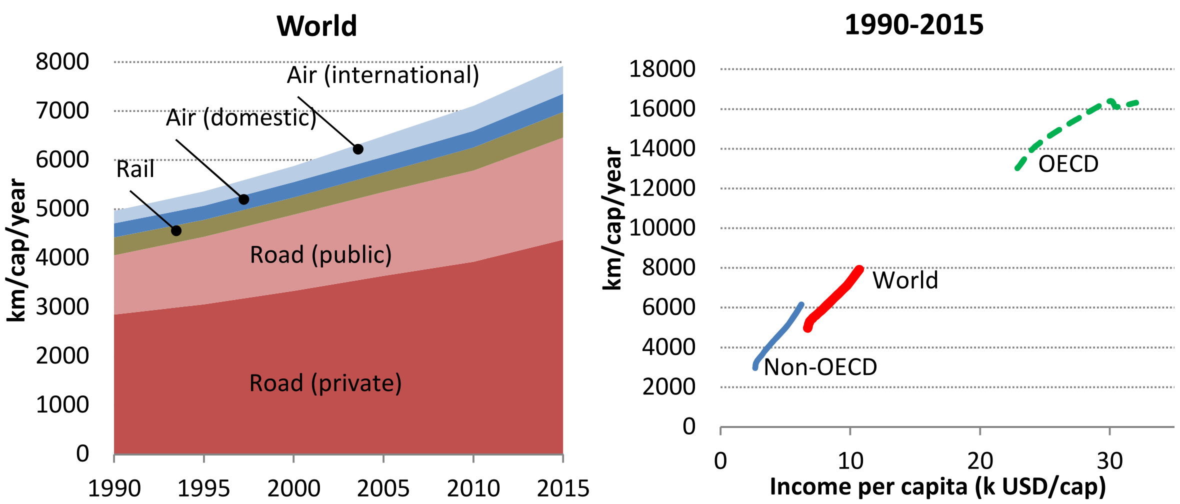
Source: equipment rate (Eurostat, 2015), (OECD, 2014).

The land-based mobility by public means (buses, rail) is driven by per capita income and average fuel prices through a positive elasticity which translates partial substitution with private means.

Air mobility grows with GDP per capita (positively) and by the average fuel price (negatively, considering both fossil-based kerosene and liquid biofuel). A distinction is made between domestic and international air transport. An additional distinction is made for intra-EU air transport.

Figure 12 shows the average evolution at world level, which has increased from 5 000 km per capita in 1990 to about 8 000 km in 2015. While there is still a large potential for mobility increase in non-OECD countries with increasing income per capita, it seems to have stabilised over the last few years in OECD countries.

Figure 12. Passenger mobility, average by mode (left), as a function of income (right)



Source: Road (public & private) from (Eurostat, 2015), (OECD, 2014), Rail (UIC, 2014), Air (ICAO, 2017).

3.3.1.2 Freight

The model describes freight transport in road, rail, air and maritime ships.

Rail and road freight in each country and region evolve with GDP, with saturation depending on population size. Road transport distinguishes between light trucks (up to 0.5 tonnes) and heavy trucks.

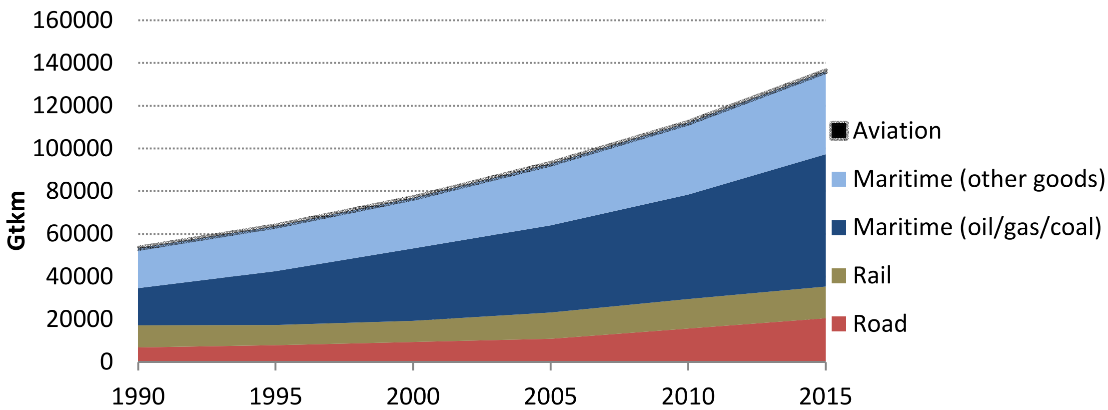
Air freight transport grows with GDP (positively) and is negatively impacted by the average fuel price (which is a blend of fossil-based kerosene and liquid biofuel).

Maritime transport is modelled at the global level and differentiated per commodity (UNCTAD 2015). The development of maritime transport is influenced by commodity-specific drivers.

Table 1. Commodities of maritime transport and their drivers

Commodity	Driver
Oil and liquid biofuel	Export and import of oil and biofuel
Coal and solid biomass	Export and import of coal and biomass
LNG	LNG flows
Iron	Primary steel production
Chemical industry	Value added of chemical industry
Other industry	Value added of other industry
Containers	Value added of all industry
Grain	Cereal trade[14]

Figure 13. Freight mobility, world



Source: Road (public & private) from (Eurostat, 2015), (OECD, 2014), Rail (UIC, 2014), Maritime (UNCTAD, 2015), Air (ICAO, 2017).

([14]) Based on look-up curves that take into account the reaction of cereals trade to the price of carbon and the price of biomass-for-energy, derived from the GLOBIOM model (IIASA 2016a)

3.3.2 Energy consumption in transport

3.3.2.1 Road

In road transport, energy service needs (for passenger mobility or freight tonnage) are separated in five vehicle types: cars, motorcycles, buses, light trucks and heavy trucks.

The model describes six different engine technologies:

Table 2. Vehicle types

Vehicle types	Description
Conventional vehicles	Internal Combustion Engine (ICE), which can function with gasoline or diesel or a blend of either with liquid biofuels
Plug-in hybrid vehicles	Combine an ICE engine and an electric battery that consumes electricity
Full-electric vehicles	Full electric battery vehicle
Gas vehicles	Compressed natural gas (CNG) driven vehicle
Hydrogen fuel cell vehicles	Fuel cell with a hydrogen tank and storage
Other fuel cell vehicles	Fuel cell, in which the hydrogen is produced on-board by using e.g. natural gas, methane, ethanol, methanol or other carbohydrates

Liquid biofuels can penetrate as blends with oil-based liquid fuels, in the consumption of ICE and hybrid vehicles. Their penetration is driven by price considerations or standards and is capped by a technical maximum blending (differentiated for biodiesel and bioethanol).

In each time step, the total demand for vehicles and the remaining vehicles per engine type after scrapping are calculated, determining the needs for new sales within each vehicle type.

Investment costs for vehicles with different engine technologies are determined based on separate cost developments of their components body, powertrain and engine.

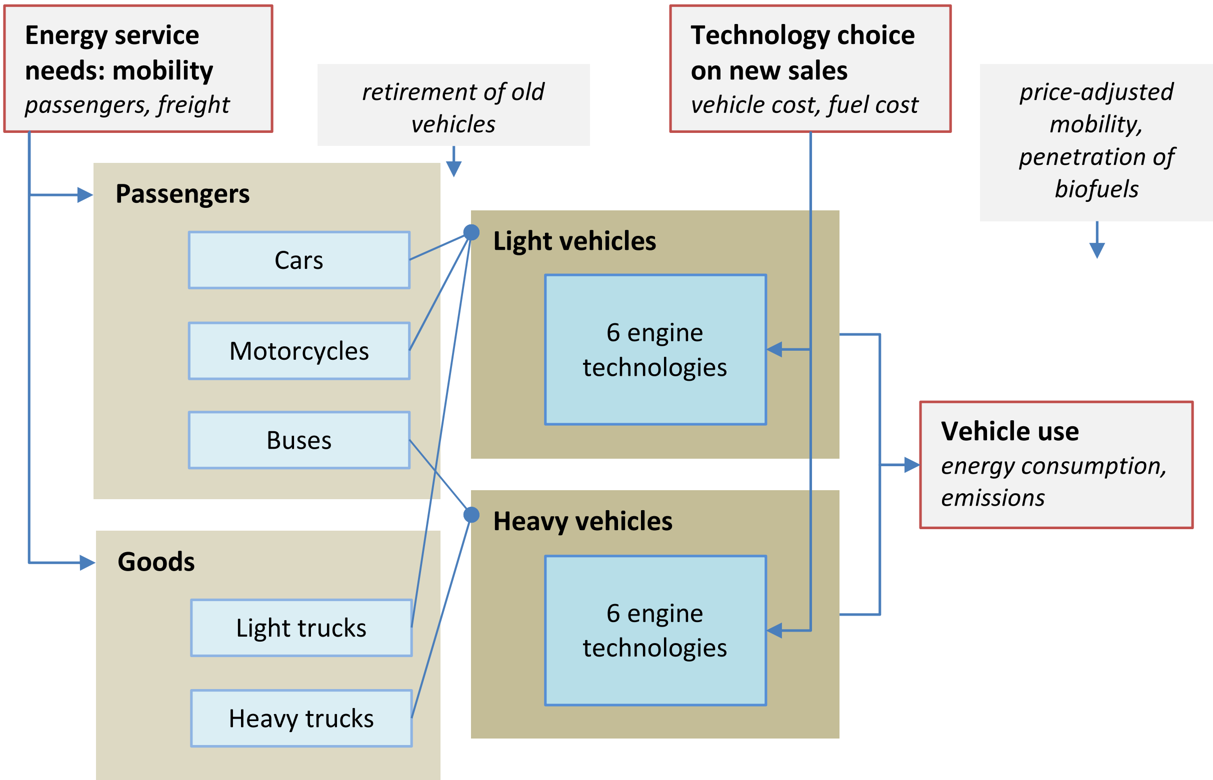
Table 3. Vehicle components

Vehicle component	Parts
Body	Body (e.g. cabin), exterior (e.g. doors), interior (e.g. seats), chassis (e.g. breaking system), electronics (e.g. convenience electronics)
Powertrain	Powertrain (e.g. transmission, electric motor) Electronics (e.g. drive electronics, board network)
Engine	Engine (e.g. base engine, engine cooling system, fuel system, battery) Electronics (e.g. engine management)

For each vehicle type a cost development on the component level was assumed. The assumptions consider the cost development of e.g. batteries, electric motor, hydrogen tank and fuel cell.

Technology substitution among the engine technologies occurs in the new sales, based on the vehicles' cost of use considering the annualised fixed cost (investment, a sector-specific time discounting factor ([15]) and lifetime) as well the variable cost (consumption and fuel price). An additional maturity factor accelerates or decelerates the adoption of new technologies, reflecting the development of new infrastructure and consumer preference.

Figure 14. Schematic representation of road transport in POLES-JRC



Fuel efficiency evolves with a price effect. Fuel or emission standards on new vehicles can be imposed.

Private and commercial vehicles use different prices for oil products as a consequence of distinct taxation regimes they are exposed to.

Actual energy consumed and GHG emissions are the result of the use of the vehicle stock considering behavioural effects via short-term price elasticities.

3.3.2.2 Rail

Rail satisfies energy services for passengers (passenger-kilometres grow with GDP and with price of road transport) and for freight (tonne-kilometres grow with GDP).

Total rail transport energy demand then follows the evolution of the total rail mobility need. It can be satisfied by three different types of fuels: electricity, oil and coal, with the last two following historically calibrated trends.

([15]) See footnote 6.

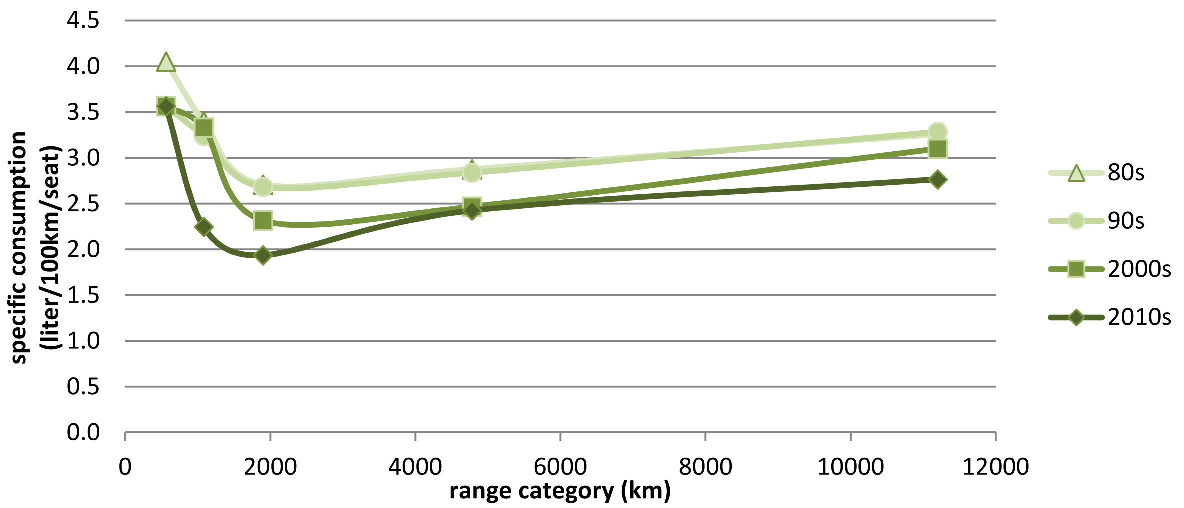
3.3.2.3 Air transport

Energy consumption for air transport is driven by the evolution of air transport demand (in passenger-kilometres and tonne-kilometres) and fuel efficiency of aircrafts.

The aircraft fleets are determined by the existing fleet, new aircrafts and scrapping. Each year a certain share of planes is scrapped (1/lifetime). New planes are brought into the market to fill the gap of scrapping and to meet the new demand.

Efficiency parameters are calculated for both the fleet and the new purchased aircraft. Flights with low ranges (e.g. 560 km) have a rather low efficiency (around 4 liter/100 seat-km). The specific consumption decreases with higher ranges and has its optimum at around 2000 km, increasing thereafter due to the increase of the weight of fuel on large distance flights.

Figure 15. Fuel efficiency of new aircrafts



Source: own calculation based on various sources from manufacturers.

To capture the effect of the link between fuel efficiency and range, new aircrafts are distinguished between five distance classes. For each country, the average flight distances for domestic and international air transport are exogenously calculated (based on statistics) by dividing passenger traffic (in passenger-kilometres) by the number of passengers carried.

The efficiency can further improve, based on the fuel price of the region or country ([16]). This is determined using Marginal Abatement Cost Curves (MACC) for new aircrafts and for the existing fleet (IATA 2013; Dahlmann et al. 2016). Among the most important measures for the existing fleet are a change of flight patterns (lower altitudes for planes), air traffic management (including ground handling), engine retrofit and cabin weight reductions. For new aircrafts the focus is set on the next generation aircrafts, redesigned for new flight patterns and more efficient engines. The implementation time for these measures depends on the region or country income per capita (10 years for highest income; 20 years for lowest income). In addition, best technologies and practices diffuse to third countries with a 10 year time lag.

The energy consumption is derived from the air transport activity combined with the overall efficiency (existing fleet and new aircrafts). Calibration factors are used to adjust the theoretical fuel efficiencies with the real fuel consumption. As the efficiency is measured in energy per seat-kilometre, air transport activity has to be converted from

([16]) New aircrafts are not designed specifically for the most expensive countries or regions, therefore in the computation the effect of fuel price in these countries is capped.

passenger-kilometre to seat-km, using a country-specific occupancy rate, which remains constant over time. In a similar way, activity in ton-km is translated into pkm assuming a weight of each passenger of 100kg (including baggage). Furthermore it is considered that half of the freight transport is carried by passenger aircrafts and the other half by dedicated freight aircrafts. These are around 10% more fuel efficient than passenger aircrafts.

Finally, energy needs for air transport are split between kerosene and aviation biofuel, based on a price competition.

3.3.2.4 Waterways

Oil consumption for domestic water transport (domestic sea lines, inland water transport) is determined by GDP and by fuel prices.

3.3.2.5 International maritime bunkers

Energy consumption for maritime bunkers is driven by the evolution of maritime transport (in tkm) and fuel efficiency of ships (in toe/tkm).

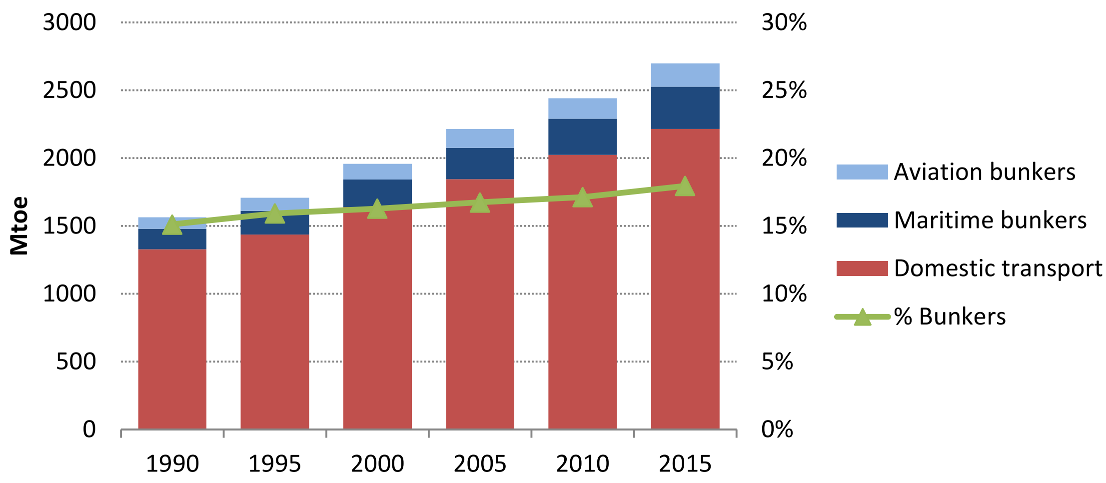
The determination of ship fleets considers the existing fleet, new ships and scrapping. Each year a certain share of ships is scrapped (1/lifetime). New ships are brought into the market to fill the gap of scrapping and to meet the new demand.

Driven by bunker fuel prices, the efficiency can improve along two MACC, one for new ships and one for the fleet (IMO 2015). Among the most important measures for the existing fleet are speed reduction, retrofit (e.g. hull), propeller maintenance and operational measures. For new ships the focus is set on propeller and propulsion measures, hull coating and air lubrication.

Energy consumption for maritime bunkers is determined by the demand for maritime transport (expressed in tonne-kilometres) and by fuel efficiency. The global maritime transport volume is split into countries and regions based on the drivers listed in Table 1 of the freight mobility section 3.3.1.2 (e.g. export and import of oil of country A is divided by global export and import of oil).

The fuel consumption is distributed between oil, gas, biofuel and hydrogen depending on the relative prices of those fuels and some additional limitations (e.g. oil tankers use mostly oil, LNG tankers mostly gas).

Figure 16. International bunkers' energy consumption and their share in total transport energy consumption



Sources: IEA 2017a, Enerdata 2017a

3.4 Agriculture

This sector actually encompasses energy consumed in the agriculture sector, fishing and forestry. It includes oil demand for running tractors and agricultural equipment.

For each fuel, total energy demand is determined by the value added of agriculture and an additional trend depending on income per capita, which reflects the potential intensification of agricultural production.

Climate policies negatively affect oil and gas consumption that are substituted by biomass and electricity.

3.5 Energy prices

Final user energy prices are calculated from the variation of import prices (themselves derived from the variation of international prices) to which is applied:

- the value added tax (in percentage),
- scenario-specific energy fiscal policy evolution (taxes, subsidies),
- environmental policy elements (e.g. carbon pricing).

By default the volumes of price components not explicitly represented in the model remain the same as historical levels (excise taxes, transport and distribution duties, other taxes and duties).

Subsidised fuels are identified at the start of the simulation by comparing final user prices with a fuel-specific reference price, which is the import price or the fuel price at the closest energy market (for fuel exporters), plus value added tax. The subsidies ratio can then be kept constant or can be progressively phased out.

Domestic final user prices of transformed fuels (electricity, hydrogen, synthetic liquids) are deduced from the evolution of production costs. Transport and distribution costs as well as excise taxes are assumed to remain constant. For electricity, the production costs of base load production are assigned to the price for industry and those of peak load to residential services.

4 Energy transformation

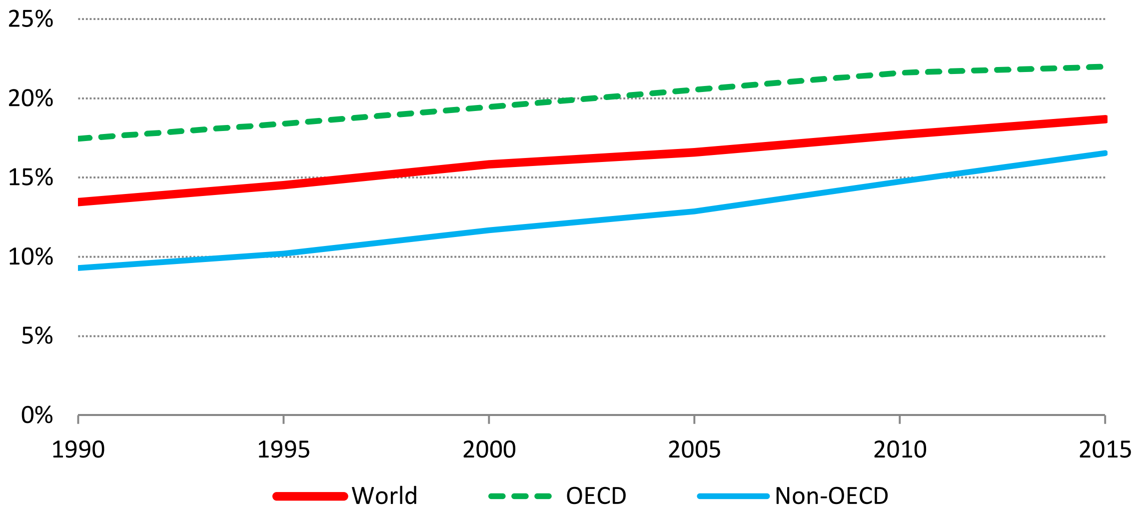
Energy transformation comprises all activities of energy conversion from primary forms of energy to end-use energy. Energy transformation consists of several sectors ([17]): refining of oil and gas, production of electricity, heat (and co-generation with electricity), hydrogen and synthetic liquid fuels from coal, gas and biomass. Most prominent within energy transformation is the electricity sector, in which a broad range of energy carriers/fuels are converted to electricity.

4.1 Electricity sector

Electricity is an energy carrier that has been experiencing an increasing role in the final energy demand, driven by the evolution of the economy towards services, electrification in industry and the widespread uptake of electronic consumer devices (including ICT applications). Figure 17 shows that this applies to all regions and that non-OECD countries in particular are catching up quickly.

At the same time, the power generation sector appears as a key sector for decarbonisation with various mitigation options that are relatively easy to implement compared to the end-user side. This further supports electrification as a way to meet carbon constraints.

Figure 17. Share of electricity in total final energy consumption, 1990-2015



Sources: IEA 2017a, Enerdata 2017a

4.1.1 Technologies for power supply

The electricity generating technologies (Table 4) include existing technologies as well as emerging or future technologies. They are categorised as either *centralised technologies*, for which operation and investments are based on a competition between grid-level plants, or *decentralised technologies*, which compete with the retail prices perceived by consumers.

The technologies are initialised for each country with the installed capacities and its vintage (Platts 2015), share of new capacities, electricity generated by technology and fuel as well as observed load factors.

([17]) The transformation of coking coal is not covered in this sector but in the iron and steel industry sector. Final energy consumption in that sector includes coal consumption for its conversion into coke in coking ovens.

Each technology has the following technical characteristics: input fuel, transformation efficiency, lifetime, self-consumption rate and CO_2 capture rate, *if applicable*.

The economic characteristics are:

- Fixed cost:
    - investment, which evolves according to technology learning curves (see Section 2.2.3 Energy technology dynamics),
    - operation and maintenance (O&M),
    - subsidies or taxes on investments,
    - for CCS technologies, CO_2 capture costs and related loss of efficiency;
- Variable cost:
    - fuel cost,
    - variable O&M cost,
    - subsidies or taxes on power output or fuel input (including a potential carbon value),
    - for CCS technologies, CO_2 transport and storage costs,
- Discount rate.

In addition, renewables have a maximum resource potential (see Chapter 5 on renewable potential). Similarly, the deployment of CCS technologies is linked to region-specific geological storage potential (and how saturation is anticipated over time).

In addition to these technical and economic characteristics, non-cost factors are calibrated to capture the historical relative attractiveness of each technology for each country, in terms of investments and of operational dispatch. In the scenarios, these coefficients evolve depending on assumptions of future societal, political and market factors. Some future technologies become mature in the future (CCS, new nuclear).

Considering a learning curve (cost component) and an increasing cost-based competition (decreased role of the non-cost component), the diffusion process follows a truly dynamic approach with path-dependency.

Table 4. Electricity generating technologies

Fuel	Technologies	Option with CCS
Nuclear	Conventional nuclear design	
	New nuclear design (e.g. Generation IV)	
Coal	Lignite conventional thermal	
	Coal conventional thermal	
	Pulverized coal supercritical	Yes
	Integrated coal gasification with combined cycle	Yes
Gas	Gas conventional thermal	
	Gas turbine	
	Gas combined cycle	Yes
	Gas fuel cell*	
	Combined Heat and Power (CHP) (*) (**)	
Oil	Oil conventional thermal	
	Oil-fired gas turbine	
Water	Large hydro	
	Small hydro (< 10 MW)	
	Tidal and wave	
Geothermal	Geothermal power	
Biomass	Biomass conventional thermal	
	Biomass gasification	Yes
Wind	Wind onshore (3 different resource quality areas (***))	
	Wind offshore (3 different resource quality areas (***))	
Solar	Photovoltaic (PV) power plant (centralised)	
	Decentralised PV (*)	
	Solar thermal power plant	
	Solar thermal power plant with thermal storage	
Hydrogen	Hydrogen fuel cell (*)	

(*) These technologies are considered as decentralised; they compete with grid electricity.
(**) Gas-fired CHP is considered as driven by electricity needs, heat co-generation is a by-product. More information on heat production can be found in Section 4.2.

(***) The onshore and offshore wind technologies have each been divided into three types of wind resource potential, based on the average wind speed for onshore technologies and on the average wind speed and distance to the coast for offshore technologies.

4.1.2 Electricity demand

The total electricity demand is computed by adding the electricity demand from each sector presented in the previous section: residential, services, transport, industry and agriculture. This is complemented by 'other consumptions', which include the self-consumption of power plants by technology (or of other energy transformation sectors), the grid losses, the water electrolysis consumption (for hydrogen production) and the net electricity exports.

The evolution over time of the sectoral electricity demand is driven by the activity of each sector, as well as by the relative fuel prices for energy needs where electricity is in direct competition with other energy carriers.

The specific challenges of the power system require a detailed representation of the electricity demand. In particular, with increasing shares of wind and solar power in the system, the load to be covered by dispatchable sources is ever more impacted by the non-dispatchable, intermittent wind and solar supply. Therefore when building the electricity load curve, we account for:

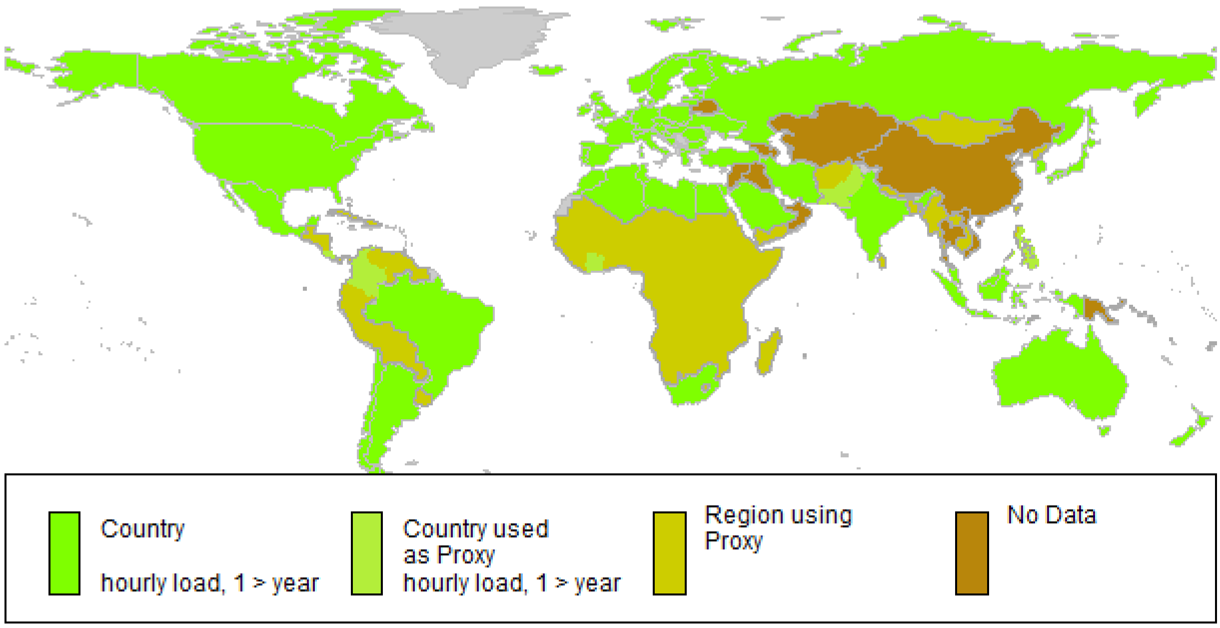
- the hourly variations (demand, wind, solar),
- the daily patterns (demand and solar),
- and the simultaneity between demand and generation from wind & solar.

These characteristics are described by a set of representative days with an hourly time-step from which the annual load curve is approximated.

4.1.2.1 Data used

The electricity load data was collected for a wide range of countries around the world, shown in **Figure 18**.

Figure 18. Map of the electricity load data collected



For some countries and regions, the electricity load is based on a neighbouring country or a representative country within the region. In this way we reconstitute reasonable hourly load profiles for all POLES countries and regions.

The meteorological data used to compute the hourly production of wind and solar capacities (wind speeds, solar irradiation, temperature) is based on NASA data (MERRA2 database, (NASA 2015a, 2015b)), which provided a global set of gridded data. The wind and solar production is then computed based on a typical production curve and a mix of current and future expected locations of plants (impacted by today's population density and the areas with high resource).

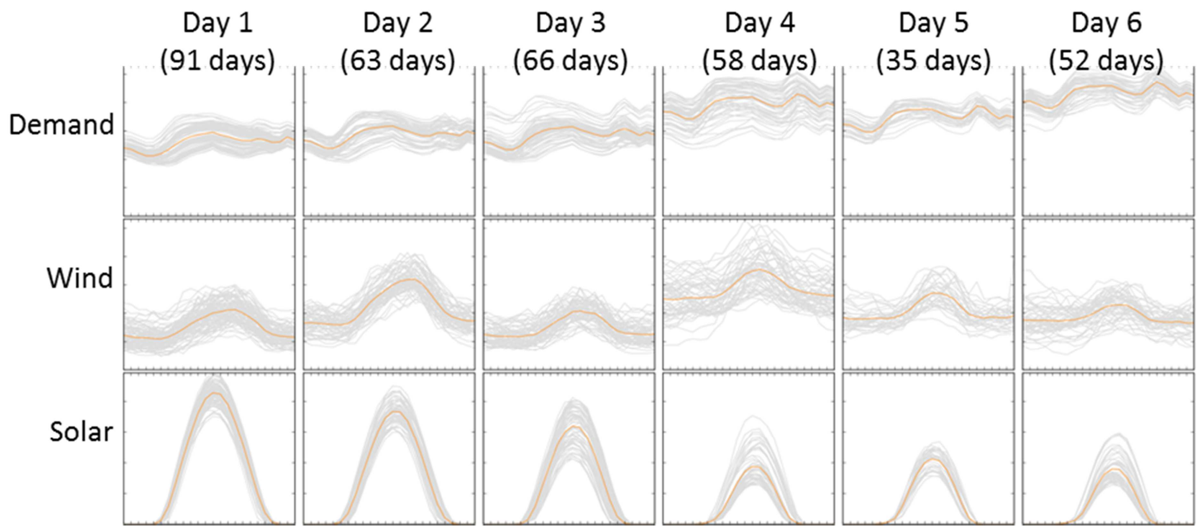
4.1.2.2 Representative days

The representative days are chosen separately for each country or region. They are based on the simultaneous profiles of electricity load and of wind and solar generation. A hierarchical clustering algorithm is used to group the data into a pre-defined number of days (six in the general case). The objective of the algorithm is to keep a maximum diversity of days, in terms of demand, wind production and solar production[18], while

[18] One cluster is composed of 72 components: 24 hours of demand, 24 hours of wind production and 24 hours of solar production, each being normalised to their annual maximum. At each aggregation step, each day

reducing the amount of data treated in POLES. Each representative day represents a different number of days of the year (see Figure 19).

Figure 19. Illustration of the aggregation of days into six representative days



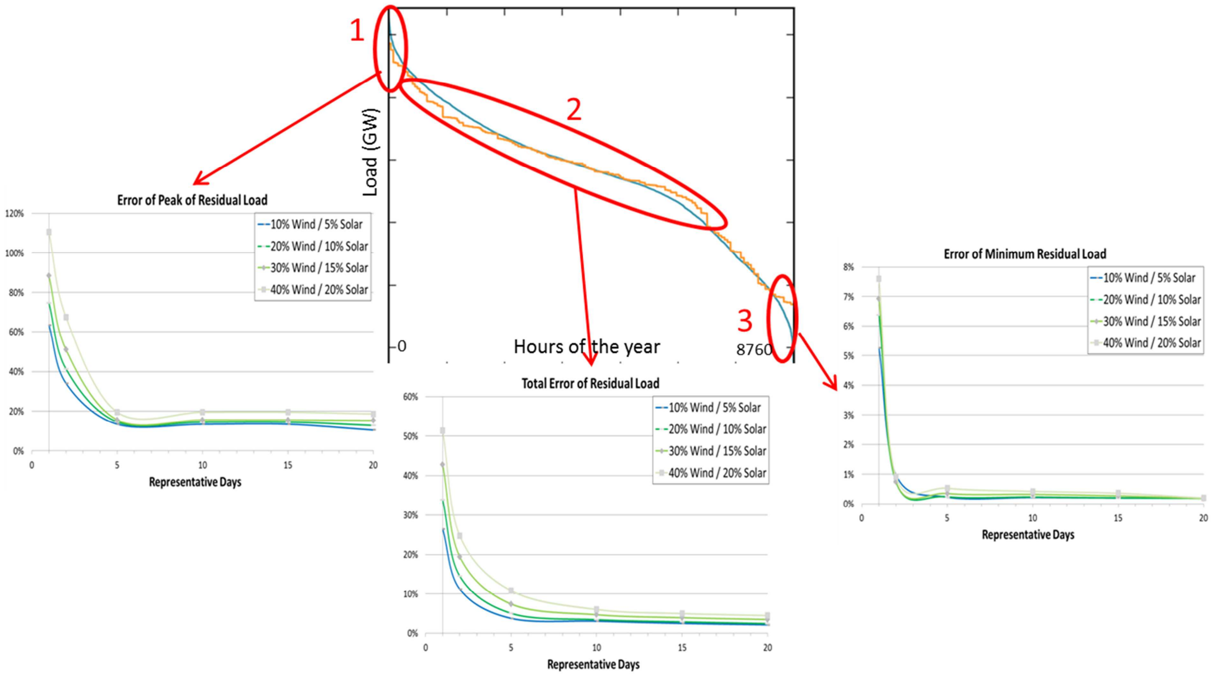
An analysis of the days grouped in each "representative day" give insights on the share of business days, Saturday or Sunday, the share of summer, winter or swing season, the average temperature, or the daylight hours.

The description by representative day was validated by evaluating the accuracy of net load (load *minus* generation form wind & solar). Net load is the relevant quantity as the non-dispatchable energy sources have a zero-marginal cost and under normal system operation will have priority before dispatchable plants with positive production costs[19]. The comparison of the representative days with the actual hourly data shows a relatively small loss of accuracy. The loss of accuracy induced by the representative days depends on the number of days; a study of the total error induced (see Figure 20) led to the choice of keeping six days per year.

or cluster of days is compared to the others with an Euclidian distance; the number of clusters is reduced progressively by merging the clusters that least increase the Euclidian distance of the resulting clusters to the original dataset.

[19] A possible exception is the thermal plants seeing a benefit in temporary negative bidding due to lack of flexibility.

Figure 20. Illustration of the accuracy loss due to the use of representative days



The three zones where the load net of wind and solar shows a loss of accuracy are:

1. The maximum residual load, of particular relevance for the dimensioning of the peaking plants investments needs. This error is computed for each region and applied in the modelling of the capacity planning process (see section below).
2. The overall shape of the residual load duration curve, impacting the number of full load hours of dispatchable plants.
3. The lowest residual load, impacting the baseload needs and/or the curtailed energy due to over-production.

The share of wind and solar in the system impact the three types of error, which is also reflected in the modelling of the capacity planning.

4.1.2.3 Description of the electricity load curve

The annual electricity demand and its decomposition per end-use are given by other sections of the model.

The end-uses are distributed between the chosen representative days based on the characteristics of the day: temperature, day of the week, season. Each end-use has an associated profile, collected from the literature and calibrated to match the actual total electricity load profile.

Therefore, the total electricity load curve of each representative day is impacted by the evolution of each electricity end-use.

4.1.3 Operation of the power system

The power sector operation assigns the generation by technology to each hour of each representative day. The supplying technologies, grid imports and production of storage technologies must meet the overall demand, including the grid exports and consumption of storage technologies. In cases of over-supply, some production curtailment is possible. The operation of the power system in POLES is simulated following the priorities and rules shown below.

The decentralised production is considered first. This includes decentralised PV, decentralised CHP, small hydro and stationary fuel cells. They are considered to be distributed at the customer site and thus compete with the retail electricity price. Their production is deduced from the total demand with set production profiles.

The resulting grid-level demand is covered in priority by non-dispatchable centralised technologies (wind, large solar with or without thermal storage, hydro run-of-river, marine). They produce according to specific profiles, which for wind and solar technologies are defined by the clustering algorithm presented above. The rest of the demand has to be met with dispatchable centralised technologies.

Nuclear and hydro lakes are calculated first. Hydro lakes offer a strong flexibility at the yearly and daily timescales (from full rated power down to 5% of average production level), while nuclear offers some flexibility (only a few percentage points) on a seasonal scale in terms of planned outages for maintenance works. Their profiles can adapt to the total load profile but also to the production of non-dispatchable energy sources (including wind and solar).

Some demand sectors also mitigate the variations of the remaining load across the year and the representative days:

- The total annual amount of net exports is fixed in time, but the hourly profile partly accommodates the remaining load;
- Hydrogen production from electrolysis can absorb electricity across the year, except during peak net load hours;
- Electric Vehicles have a smart charging across the day (lower demand when other sectors' load is high), although vehicles are topped up at the end of the night (not all the load can be placed at sunlight hours);
- Hydro pumping and other storage technologies (stationary batteries, Compressed Air Energy Storage, Vehicle-to-Grid and Demand Side Management) add further flexibility, storing when the remaining demand is low and producing when it is high. Each technology has its characteristics but the modelling limits their operation within a day.

Finally, production curtailment is allowed in the case of a combined oversupply of solar, wind, hydro, marine and nuclear power and once storage consumption is accounted for.

The remaining technologies, constrained by their available capacity on each hourly block, compete based on their variable production costs taking into account a non-cost factor based on the historical tendencies of dispatching practices.

The electricity prices are based on the result of this dispatch: a price for industrial consumers is derived from the evolution of the average cost of supplying the industrial loads, while the electricity price for other consumers follows the evolution of the average cost of supplying the non-industrial loads.

The operation of the power technology also gives the overall primary fuel consumption of the power sector.

4.1.4 Planning of electricity capacities

4.1.4.1 Production capacities

Decentralised technologies are planned separately, and compete directly with electricity retailing companies. All other technologies are developed in a balanced mix to cover the expected electricity demand from the grid. The capacity planning modelling is an intent to account for the particular non-dispatchable nature of wind and solar.

The current and expected load is described by the days chosen with the clustering algorithm, at hourly time-step. Using six days gives 144 time-steps of different weights (according to the weight of each of the representative days).

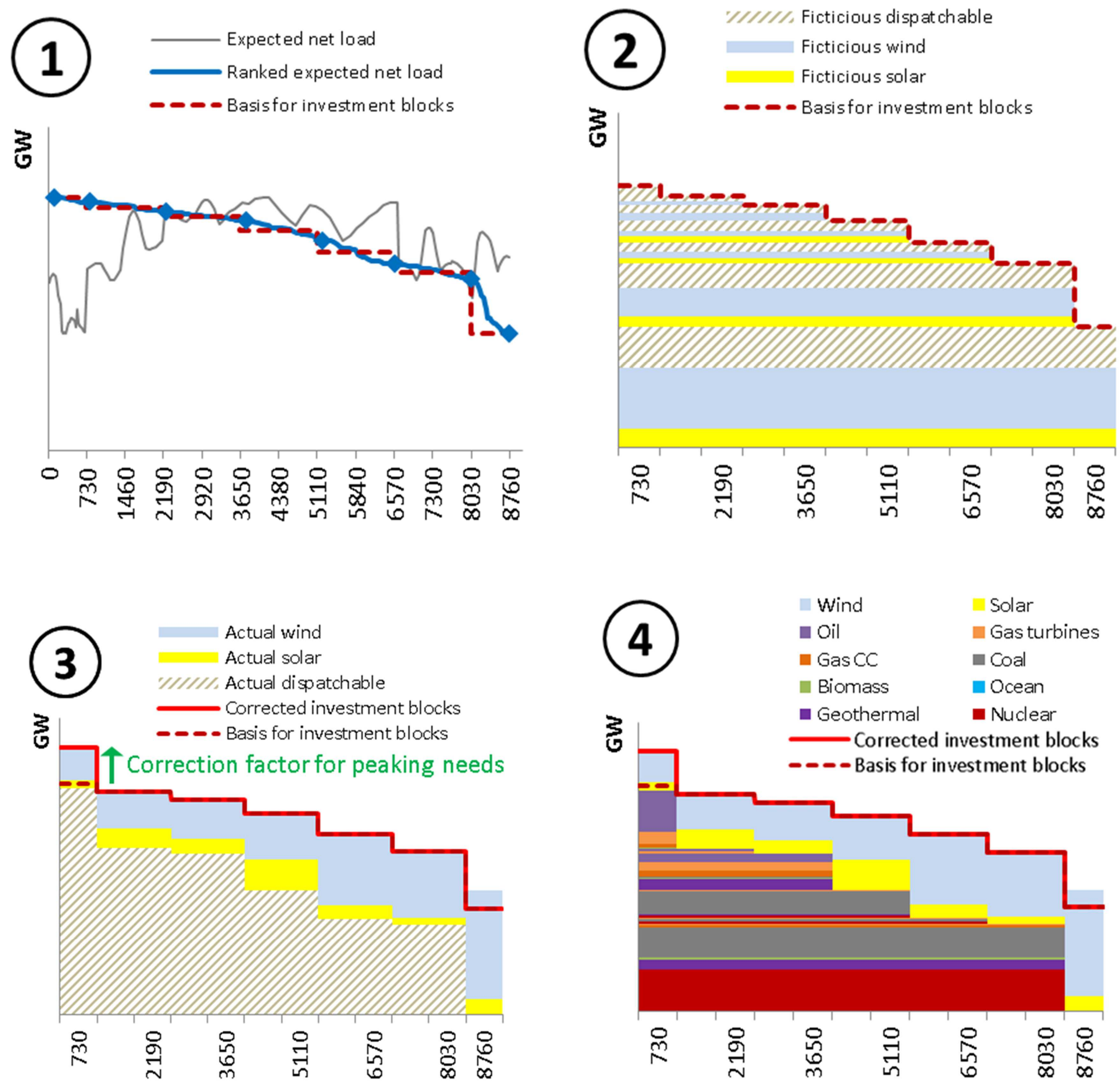
The investment decisions are taken based on the 10-year trend of demand, net of the extrapolated contribution of decentralised and storage technologies and of the expected remaining capacities of centralised wind and solar in 10 years.

1. The resulting expected net demand is ranked into a residual load duration curve, which is then distributed into seven blocks of different expected capacity factors, from peak to base load.
2. On each block, wind and solar are confronted with dispatchable plants in a first competition ("fictitious" investments).
3. It is assumed that the investment block that leads to most wind and solar gives the total amount of wind and solar built (because of their particular non-dispatchable nature). The investment blocks are then updated by subtracting the actual contributions of new wind and solar in each of the blocks, the rest of expected load being covered by dispatchable plants. Peak load is also scaled to account for the loss of accuracy in peaking needs due to the choice of representative days (correction factor calculated prior).
4. Dispatchable plants are distributed per block following a portfolio approach, accounting for both the total production cost per load block and a historically calibrated non-cost factor. This factor represents technical availability (e.g. CCS technologies starting in 2030, new nuclear technology starting in 2050), technical constraints (e.g. flexibility across load blocks), country policies (e.g. statute on building new nuclear) and other non-cost factors (calibrated on recent historical patterns of investment).

For some technologies, a maximum potential caps the installable capacities (CCS, biomass, wind, solar, geothermal, ocean).

Figure 21 shows graphically the capacity planning process in an example country.

Figure 21. Illustrative capacity expansion mechanism



This process determines what new wind and solar capacities are to be built and what dispatchable capacities are expected in total. The decommissioning of old plants is captured through the vintage of installed capacities. The expected need for dispatchable capacities in 10 years is compared to the capacity expected to remain in 10 years and an investment gap is computed. Finally, the actual investments carried out on the following year are a tenth of that identified gap. In this manner, the electricity module of the model recognises the importance of inertia, caused by the particularly long lifetime of equipment. The computation of expected needs is updated every year (rolling myopic expectations) and the investments adapt accordingly.

4.1.4.2 Storage and demand response capacities

Electricity storage capacities and demand response (DR) capacities are not net generating capacities and are therefore not directly competing with generating capacities. However, storage and DR can combine several economic values, represented in POLES as follows:

- Arbitrage: buying and selling in the gross market; here we focus on storage within a day; this value is the sum across representative days of all potential profits allowed by power prices for a storage plant operator (including storage efficiency losses);

- Capacity: equivalent of capacity markets and/or discharging at times of very high power prices; this is approximated by the minimum of the fixed cost of the plants built in a given country or region, reflecting the cost of an additional peaking plant prevented by additional storage;
- Ancillary services: frequency and balancing reserves, usually contracted with system operators; an indicative value is computed (based on hydro revenues in the French balancing market in 2008 and 2013) and indexed on the share of wind and solar in the system (because of their variability that the system has to cope with).

The capacity and ancillary service values are shared with already existing storage and DR plants. The sum of all values of a potential new storage or DR capacity is compared with the annualised investment cost and investment decisions follow accordingly. Storage and DR are capped by a maximum potential.

4.2 Heat production

Sectoral district heat demand follows a trend.

The related supply comes from co-generation, either distributed or centralised in some regions (represented in the model as a by-product of electricity) or from heat plants (which follow the heat demand).

Heat from low-temperature solar develops through a logistic curve that compares the cost and potential of solar heat to the average price of fuels for space and water heating. A higher return on investment triggers more investments.

4.3 Hydrogen

The complete processing chain for hydrogen use, production, transport, delivery and storage is represented.

4.3.1 Hydrogen demand

Hydrogen demand comes from:

- Stationary sources:
  - hydrogen fuel cells in industry, residential and commercial sectors; their use is in competition with grid electricity and other forms of distributed power generation;
  - hydrogen can also be mixed with natural gas and used for thermal applications;
- transport sources: road transport, in private cars and freight transport, where two types of engine use this fuel: hydrogen fuel cell vehicles and direct thermal hydrogen engine vehicles.

Table 5. Hydrogen demand sectors

	Fuel cell	Direct combustion
Stationary	Distributed power generation in demand sectors (industry, residential, services)	Mixed with natural gas in gas grid
Transport	Engine type in road transport vehicles (passenger, freight)	Engine type in road transport vehicles (passenger, freight)

The hydrogen prices for each sector are derived from production costs and transport and delivery costs (see below).

4.3.2 Hydrogen production

Hydrogen can be produced through chemical, thermo-chemical or electrical routes. Table 6 shows the different hydrogen production technologies represented in the model.

Table 6. Hydrogen production technologies

Energy input	Process	Option with CCS
Gas	Gas steam reforming	Yes
Coal	Coal gasification	Yes
Oil	Oil partial oxidation	
Biomass	Biomass pyrolysis	
	Biomass gasification	Yes
Solar	Solar methane reforming	
	Solar thermal high-temperature thermolysis	
Nuclear	Nuclear thermal high-temperature thermolysis	
	Water electrolysis with dedicated nuclear power plant	
Wind	Water electrolysis with dedicated wind power plant	
Grid	Water electrolysis from grid electricity	

The projected hydrogen production capacities are calculated on the basis of the total costs: investment costs and fuel costs (and storage cost for CCS options). Each year, production among the different technologies is distributed based on the variable costs of each technology and under the constraints of existing capacities.

4.3.3 Hydrogen transport

Due to its relatively low volumetric energy density, transportation and final delivery to the point of use is one significant cost component of the hydrogen supply.

Five transport chains are identified in the model, being combinations of the type of plant that produces hydrogen (big, small), the transport means (pipeline, truck) and the type of use downstream (direct use for stationary demand, refuelling stations for mobile demand).

Table 7. Hydrogen transport chains

Transport means			
		Pipeline	**Truck**
Capacity of production	**Large**	1. Direct use 2. Refuelling station	n/a
	Small	3. Direct use 4. Refuelling station	5. Refuelling station

The calculation of the cost of transport and delivery in the model is realised as the sum of:

- the cost of transport, which depends on the hydrogen flow in this chain, on the population density and on the distance of transport in this chain (itself depending on the size of the installations and population density);
- the delivery cost, which depends on the size of production installations and population density;
- the variable cost, which depends on the type of consumption for every chain (electricity or diesel oil for the transport by truck).

For each demand sector, a loss factor on transport and distribution is added.

4.4 Synthetic liquids

4.4.1 Liquids from coal and gas

Liquids from coal and natural gas can contribute to the demand for liquid fuels.

The development of liquefaction is determined by the comparison of the process cost with the difference between the value obtained from selling liquid products on the international oil market and the value of the coal or gas directly sold on the corresponding national or regional market. The diffusion follows a logistic curve.

The liquefaction processes are described by investment costs and conversion efficiencies. Both routes exist with the option to do carbon sequestration.

Coal liquefaction and gas liquefaction take place in a limited number of regions, identified as key coal or gas producers.

4.4.2 Liquids from biomass

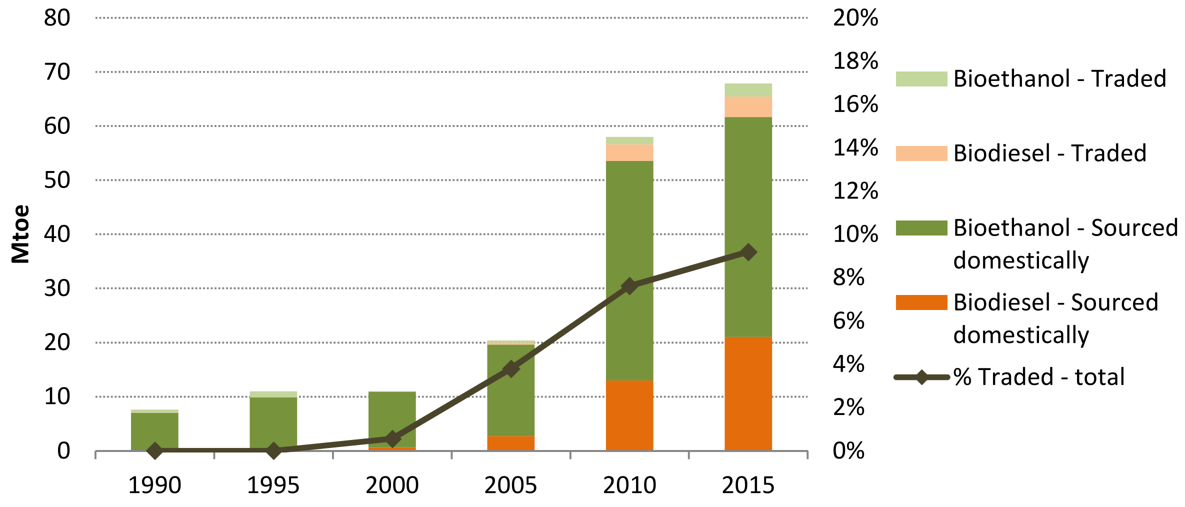
Different liquid biofuel types are distinguished: first-generation biofuels (biodiesel and bioethanol from dedicated agricultural crops) and second-generation biofuels (biodiesel and bioethanol from cellulosic materials) (see Section 5.3 Biomass for the supply of solid biomass).

Demand for liquids from biomass is driven by competition with fossil-based liquids in the transport sector, subject to a technical cap on blending.

The model identifies four production technologies: biodiesel first generation, biodiesel second generation, bioethanol first generation and bioethanol second generation. The production technologies are described with fixed investment costs, O & M costs and a conversion efficiency. Additionally, second-generation technologies exist with and without CCS. For each biofuel a cost-based competition takes place to distribute new production capacity between the various options.

International trade is allowed and competes with domestic production. The international price is set as the average of global production costs and an international transport cost. A cost-based competition takes place to allocate that production, based on each region's production cost and each region's remaining potential for biomass for liquefaction.

Figure 22. Biofuel production for domestic consumption and for international trade, world



Sources: IEA 2017a, Enerdata 2017a

4.5 Carbon Capture and Sequestration

The modelling represents several CCS technologies.

CO2 capture technologies for CCS are described by a set of techno-economic parameters, reflecting extra investment cost and decreased efficiency compared to their non-CCS counterpart (Freund and Davison, 2002); they also include a cost component for CO2 transport and storage (Zero Emissions Platform, 2011), which consists in a cost curve that increases with the use of the storage potential.

The power sector allows the development of CCS associated with biomass (with gasification), gas (combined cycle) and coal (supercritical pulverized coal and integrated coal gasification with combined cycle). These technologies are not developed as peaking plants.

Direct Air CCS (DACCS) is also represented as a backstop option (Socolow 2011). Its electricity and heat consumption are accounted for. Its development is dependent on a return on investment given its production costs and revenue it could get from funds generated by carbon pricing policies.

Industry can also implement CCS with a cost premium when their process uses biomass or coal (for example in steel production). A maximum CCS penetration potential is associated with each industrial branch, reflecting the fact that CCS is more likely to be used in large installations.

Several fuel transformation processes can be coupled with CCS: second generation biofuels, hydrogen (with biomass gasification, coal gasification and gas steam reforming) and liquids from coal or gas.

The development potential of CCS is constrained by technology availability, starting in 2030 with a progressive adoption and diffusion. The development of CO2 transport and sequestration infrastructure is assumed to stay in the range of the historically observed annual growth of oil and gas transport infrastructure, or to be able to reuse that infrastructure if oil and gas demand decreases. CCS is also constrained by a geological storage potential by region (IEA 2009, 2010), and by an anticipation of its saturation; ocean storage can then become an option at higher cost.

4.6 Other transformation and losses

Losses and self-consumption in oil refineries are determined with an efficiency factor and the ratio of oil products needs covered by domestic refineries (calculated on historical energy statistics.

Transport and distribution losses for coal, gas and oil are calculated with factors based on historical energy statistics.

Own-consumption for oil, gas and coal production is calculated per fuel type and adjusted to historical statistics.

The remaining energy consumption in the energy sector ([20]) is captured through a coefficient based on historical statistics.

([20]) Other treatment of fuels (e.g. uranium, gas, coal refineries), gas infrastructure (e.g. operation of LNG storage facilities) and operation of water distribution system.

5 Primary energy supply

All existing primary energy fuels are represented in the model: oil, natural gas, coal, uranium, biomass, hydro, wind, solar and geothermal. In the case of fossil fuels and biomass the representation further distinguishes fuel types by fuel quality and production technology.

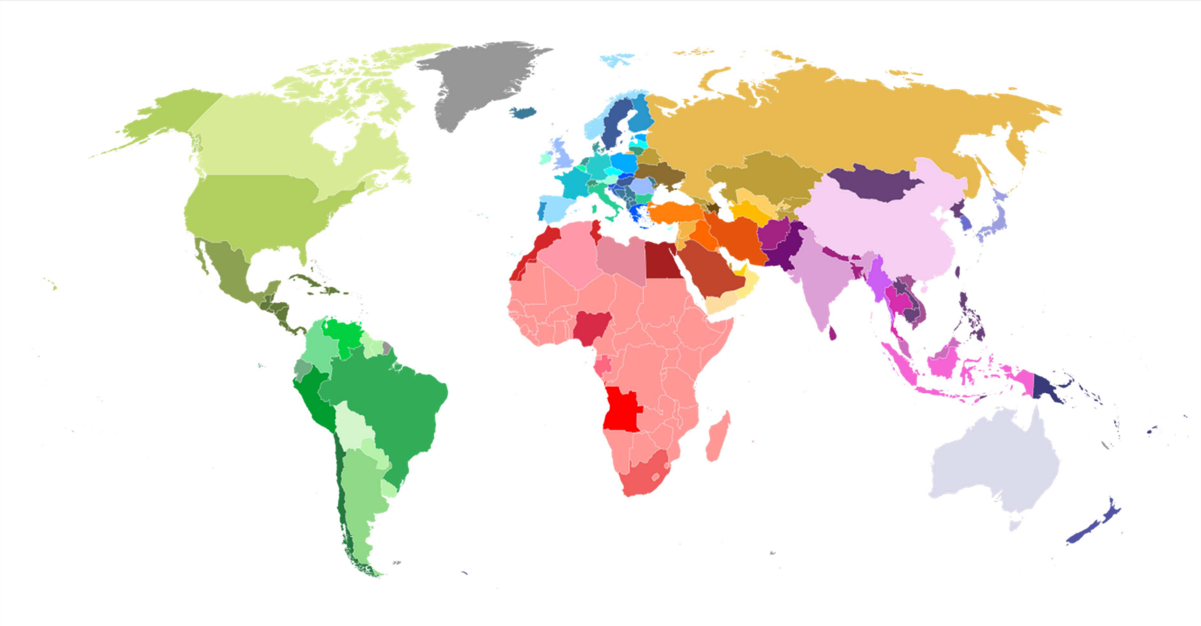
GHG emissions from fossil fuel production and transport are represented in the modelling: CO_2 from energy used in resource extraction (see below) and CH_4 from fugitive emissions in both production and transport (see Section 6.1.2.2).

5.1 Oil and gas

5.1.1 Geographical disaggregation and fuel types

The model describes 88 producers of oil and gas (countries or groups of countries), shown in Figure 23.

Figure 23. POLES-JRC geographic breakdown for oil and gas



The following oil types are taken into account:

- crude oil of onshore fields;
- crude oil of offshore fields, including deep-water oil (> 500 m depth);
- tight and shale oil;
- extra-heavy oil;
- other 'non-conventional' resources: bitumen (oil sands) and oil shale (kerogen);
- Arctic oil (north of the Arctic Circle).

In addition, natural gas liquids (NGL) are accounted as oil supply; the amount of NGL is derived from gas supply based on the wetness index of each producer.

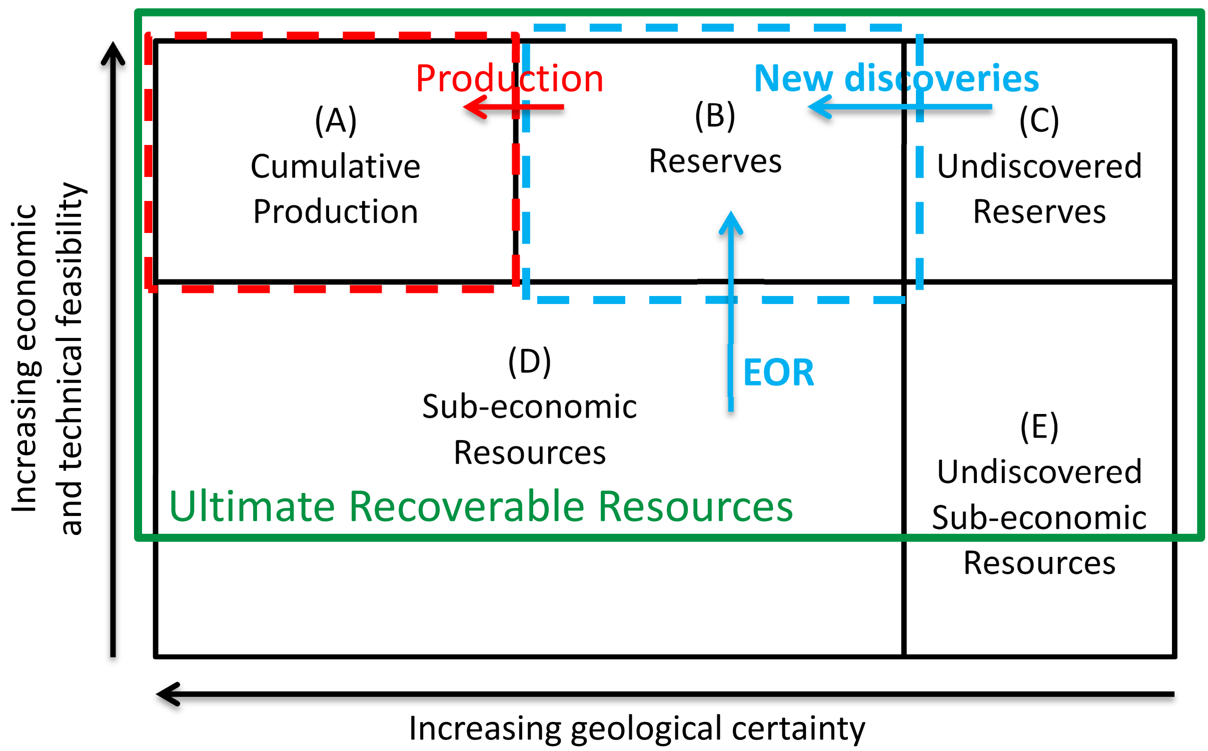
For gas, the following fuel types are distinguished:

- natural gas of onshore fields;
- natural gas of in offshore fields, including deep-water gas (> 500 m depth);
- shale gas;
- Arctic gas (north of the Arctic Circle);
- coal-bed methane.

5.1.2 Discoveries: from resources to reserves

Known oil and gas fields which are economically feasible for extraction are classified as reserves; cumulated discoveries are the historical cumulative production and the current reserves. By comparison, the resources include reserves and additional fields which are not feasible for extraction or undiscovered. Figure 24 represents the segmentation of oil resources and reserves and its possible evolution, with economic and technical feasibility along its y-axis and the certainty of reserves and resources along its x-axis. The ultimate recoverable resources (URR, green rectangle) are crucial inputs to the model, based on geological surveys (BGR 2015, USGS 2013, Schenk 2012).

Figure 24. Schematic representation of the oil sector from resources to reserves



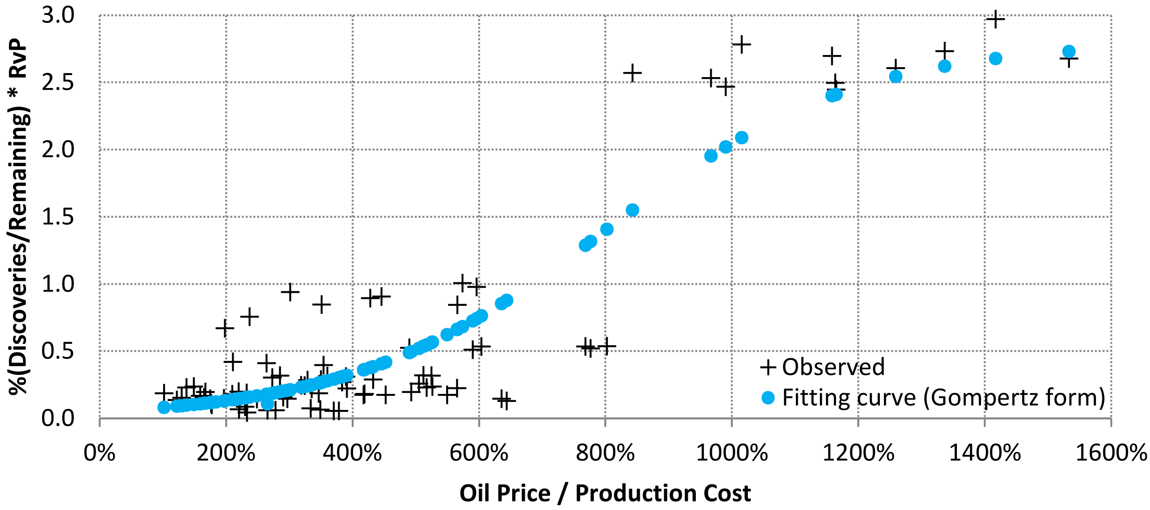
Source: Derived from McKelvey (1972).

For each fuel type, the modelling of reserves increases in two ways:

- For oil and gas, new fields discovery (*arrow from (C) to (B)*): each year, the level of new discoveries is defined by a curve of decreasing returns of the remaining undiscovered resources. For any given year, discoveries are dependent on the profitability ratio of fuel market price to production cost (i.e. no discoveries are made if the production cost exceeds fuel market price); an example of this correlation is provided in **Figure 25**.
- For oil, enhanced oil recovery (EOR, *arrow from (D) to (B)*) that increases the size of discovered reserves; for any given year, the increase of the recovery ratio is dependent on the differential of oil price and operational expenditure. The recovery ratio is capped by a maximum ratio of oil in place (typically 70 %).

The reserves are computed as the difference between cumulative discoveries (including EOR) and cumulated production. The production cost of each producer is defined by a weighted average of production costs for new and existing reserves.

Figure 25. Correlation of new discoveries (expressed as a share of remaining resources to be discovered and scaled by the Reserves/Production ratio) and the Oil price / Production cost ratio, for conventional onshore oil



Source: Derived from BP Statistical Review (BP 2015). Data for 2008-2015.

Note: Discoveries are expressed as a share of the remaining resources to be discovered (resulting volume of new discoveries decreases as more discoveries are made) and are scaled by the Reserves/Production ratio, reflecting historical pattern of exploration activity.

5.1.3 Production costs

Production costs are distinguished between investment costs (R&D, exploration, infrastructure), operational costs (notably energy inputs in production) and additional costs (taxes, royalties). Production costs per fuel type refer to a range of sources ([21]). Production costs are further disaggregated in direct energy and indirect energy components. Direct energy needs per fuel rely on literature ([22]).

The decomposition is the following:

Investment costs (capital expenditure, CAPEX):

- *Direct component*: reflects the energy embedded in infrastructure construction; energy efficiency in materials production decreases costs.
- *Indirect component*: reflects the non-energy costs related to technological R&D, exploration activities and services required for the preparation of a production facility. It is calibrated on the historical investments dedicated to exploration of oil producers. Energy intensity decrease indirectly decreases costs (the energy intensity of services was used in this modelling). This indirect component increases with the oil price.

Operational costs (operational expenditure, OPEX):

- *Direct component*: refers to energy inputs in production, detailed by production step, and linked to output and to Energy Return On energy Invested (EROI).
- *Indirect component*: reflects the inputs embedded in materials production for new machinery, fuel usage in various support services, as well as purely non-energy components such as labour costs and other costs; these indirect energy needs are converted into costs using the energy intensity of the economy.

([21]) Databases: knoema; Rystad Energy UCube. Reports by: Arthur D. Little; BREE Australia; Credit Suisse; Deutsche Bank; EIA; Energy Studies Institute, NUS; Exxon Mobil; EY; IEA – ETSAP; IEA World Energy Investment 2016; IHS CERA; Morgan Stanley; Oxford Institute for Energy Studies; Shell; WGM Nexant. Articles in: CNN; Financial Times; Natural Gas Europe; oilprice.com; Slate; Wall Street Journal.

([22]) Aucott 2013, Brandt 2008, 2011, 2013, 2015, Ghandi 2015, Nguyen 2012

These components are allocated to the various production fuel types as shown in Table 8.

Table 8. Oil and gas production cost components and its drivers

Component:	Representing:	Initial value based on:	Evolution driven by:
CAPEX direct	Production facility, other CAPEX	Rest of CAPEX	Energy intensity of steel production
CAPEX indirect	R&D, exploration	Share of CAPEX	Oil price, Energy intensity of services
OPEX direct	Drilling, pumping	Literature, per fuel type	Fixed % of output or EROI; cost of energy (per fuel type)
	Steam needs	Literature, per fuel type	EROI; cost of energy (per fuel type)
	Other energy	Literature, per fuel type	Fixed % of output; cost of energy (per fuel type)
OPEX indirect	Support services, labour costs, other OPEX	Remaining OPEX	Energy intensity of GDP
Taxes, royalties	Taxes, royalties	Literature	Scenario-dependent

Note: For producers where only total production cost was found in the literature, a split into components was made based on neighbouring producers for the same fuel type.

Three production steps are distinguished in oil and gas production: drilling and pumping (energy for drilling, injection and lifting); heat (energy for upgrading the underground resource into synthetic crude); other (energy for transport, lighting, etc.). Table 9 details these steps by fuel type produced and how the energy requirements for each evolve over time in the modelling.

For each step, energy is used in different forms, either directly or locally transformed with conversion efficiencies (e.g. fuels to produce steam, fuels to generate electricity on-site). The energy fuels can come from energy markets (purchased) or from the own gross production (own-use). The opportunity cost is compared to the prices for industry and the competition determines how much fuel is bought.

The sum of fuel inputs across production steps and fuel types, net of energy own-use, are identified in energy statistics as the energy inputs in the oil and gas sectors.

Table 9. Energy inputs per production step and per produced fuel

Production step	Production fuel type	Total energy need	Energy used in the form of…	… supplied by…	… provided by:
Drilling and pumping	Onshore	fixed % of output, EROI	oil, electricity	oil, grid electricity	purchased
	Offshore, Arctic	fixed % of output, EROI	oil, electricity	oil, gas, grid electricity	own-use, purchased
	Tight oil	EROI	oil, gas	oil, gas	own-use
	Shale gas	EROI	oil, gas	oil, gas	own-use
Heat	Onshore, Heavy oil	EROI	steam	oil, gas, coal, biomass, nuclear electricity	own-use, purchased
	Kerogen	EROI	electricity	oil, grid electricity	own-use, purchased
Other	All except heavy oil	fixed % of output	oil, electricity	oil, grid electricity	purchased
	Heavy oil	fixed % of output	oil, electricity	oil, grid electricity	own-use, purchased

For each step, energy needs can evolve either proportionally to produced output (fixed share found in literature) or as the result of the EROI curve.

The EROI curve captures rising energy requirements, and thus costs, for additional resource extraction with increasing cumulative extraction ([23]):

$$EROI = \frac{1}{\alpha + \frac{Cum.Prod}{URR}} + \beta$$

With: α, β = parameters per fuel type, defined by historical production;

Cum.Prod = cumulated production;

URR = ultimately recoverable resources.

For each fuel type and production step, the EROI curve defines total energy needs. The EROI-dependent components in Table 9 are the remaining energy needs once all other components are calculated.

5.1.4 Production process and trade for oil

The oil market is considered as one 'great pool' with no regional markets. Only net imports and exports are calculated for each country or region.

World oil demand is met by existing production facilities (calculated based on last year's production with an average decline rate per oil type) and new production.

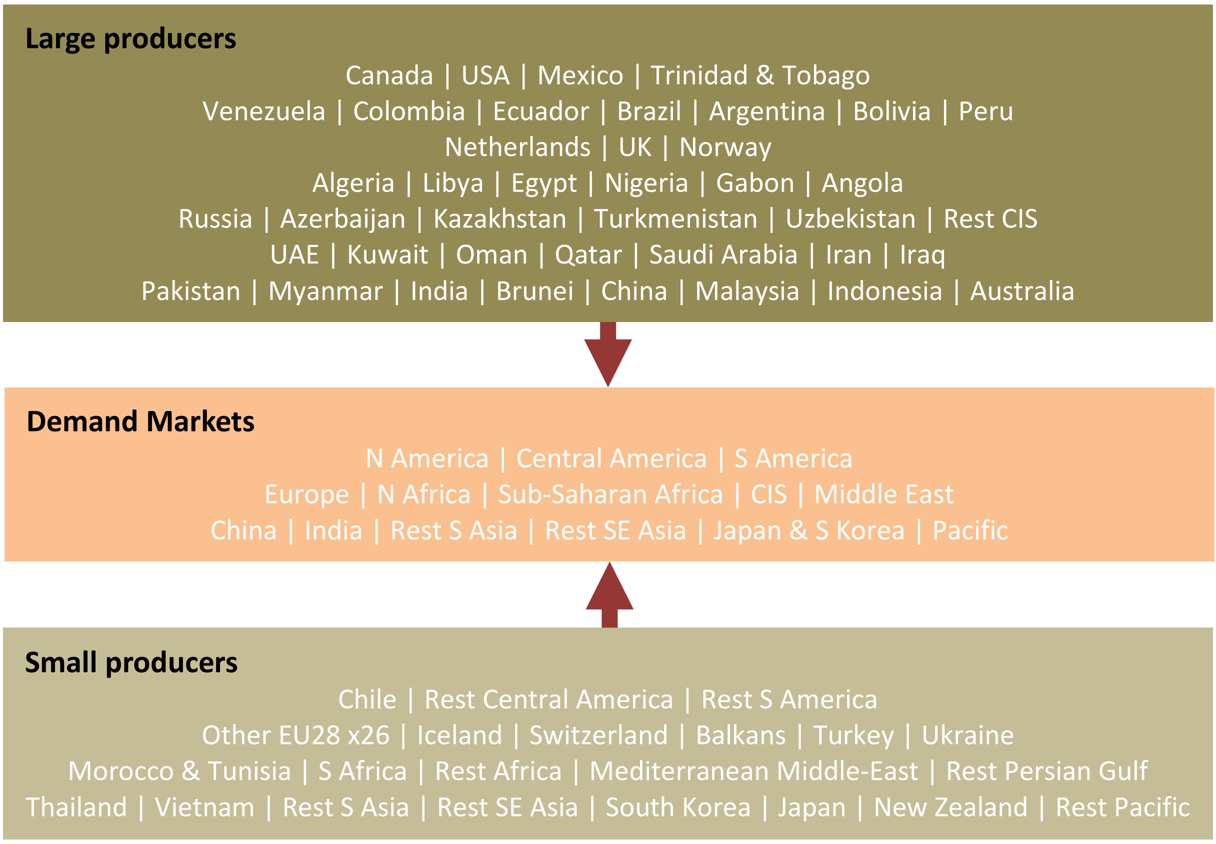
([23]) The perimeter of the energy spent and the energy produced is the production facility. Energy to refine the fuel into final products and distribute it to final users is captured in other parts of the model.

The new production is distributed across producers following their variable production costs and some constraints on production capacity, based on the Reserves/Production ratio (a minimum value reflects resource management policies) and on annual growth of production capacity (historical expansion when available, exogenous assumption for new producers/resources).

5.1.5 Production process and trade for gas

The global gas consumption is split into 14 regional markets that are supplied by the 88 producers (see **Figure 23**), differentiated into small producers (47), which produce only for domestic needs, and large producers (41) that can export to meet the demand of all 14 markets, net of the contribution of the (small) local producers. These trade flows are directional (from producers to the different consuming markets).

Figure 26. Mapping of gas producers and demand markets

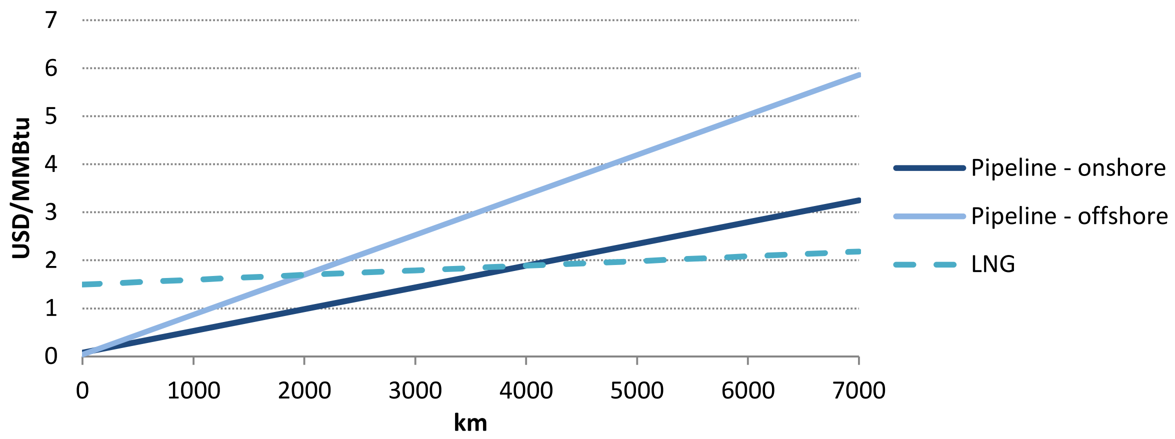


Note: Large + small producers correspond to oil producers (Figure 23). 'Rest' regions exclude the relevant singled out producers; they are different from the energy demand and coal production regions.

The modelling first assesses the export capacities of large producers towards each of the regional markets. In a second step, the actual supply by each producer is computed.

The model identifies three types of transport routes for gas: onshore pipeline, offshore pipeline and LNG. All routes from producers to markets are characterised by a distance and a cost (see **Figure 27**).

Figure 27. Gas transport costs in the POLES-JRC model



Source: GasNatural Fenosa (2012).

The development of existing export capacity per route considers the evolution of the consuming market, a depreciation of existing capacities and the producer's capability to continue supplying that route given its reserves. New trade routes can emerge if the producer has enough reserves and if the return on investment justifies it (gas selling price in a new market vs. production cost and transport cost to that market).

Actual gas supply (all gas types combined) is then calculated based on the use of these capacities. Market shares are determined by the historical trade matrix, the exporter's reserves/production ratio and the variable costs over the route.

For each exporter, total gas production towards all routes is then distributed across each gas type. Production is met by existing production facilities (calculated on last year's production with an average decline rate per gas type) and new production facilities.

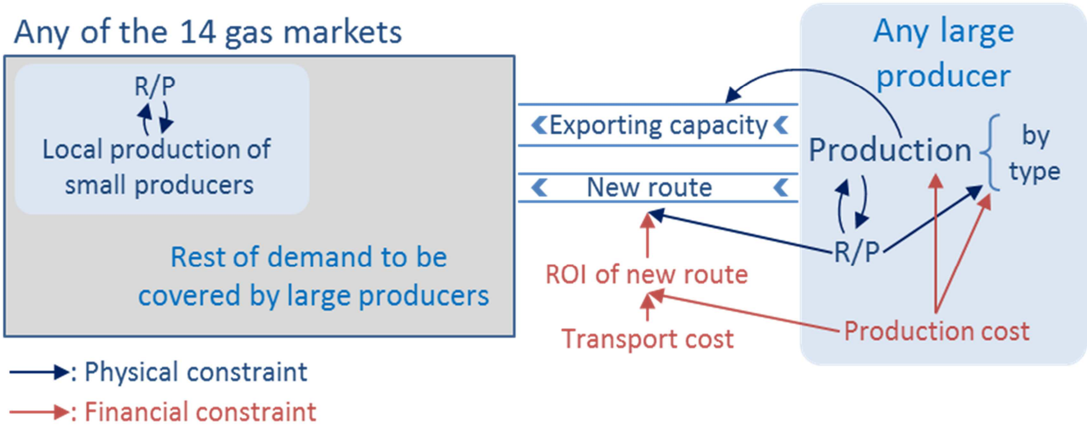
Total needs for new production is distributed across gas types following their production costs and some capacity constraints, based on the Reserves/Production ratio (a minimum value reflects resource management policies) and on annual growth of production capacity (historical expansion when available, exogenous assumption for new producers/resources).

For small producers, gas production per gas type evolves with:

- Reserves, evolving as explained in Section 5.1.2.
- The Reserves/Production ratio, following a standard equation influenced by gas market prices (and capped by a minimum value to reflect resource management policies).

A simplified diagram of the production and trade module is shown in Figure 28.

Figure 28. Schematic representation of the gas production and trade module



Note: ROI is Return on Investment, R/P is the ratio of reserves over production.

Additional gas sources

The modelling also identifies additional sources of natural gas. These correspond to recovered methane that would otherwise be emitted; instead they are used as energy sources (see Section 6.1 Greenhouse gases):

— urban waste methane;

— underground coal methane;

— fugitive emissions of the gas production.

5.1.6 Prices

The oil price converges towards a value that depends on the following factors:

- the marginal production cost, derived from the cumulated production curve ranked according to production costs across all oil types;
- an indicator of resource scarcity, based on the evolution of the Reserves/Production ratio across all producers and oil types;
- an indicator of production capacity saturation, based on the effective use of newly installed capacities over all producers and oil types;
- oil stocks variations, which either add a mark-up above the marginal price or deflate the price towards the average production cost; the effect of historical stocks variation is progressively phased down over time, assuming a balance over the long run.

For gas, in each of the 14 importing markets, the price is calculated as a weighted average of LNG and pipeline suppliers' prices, with:

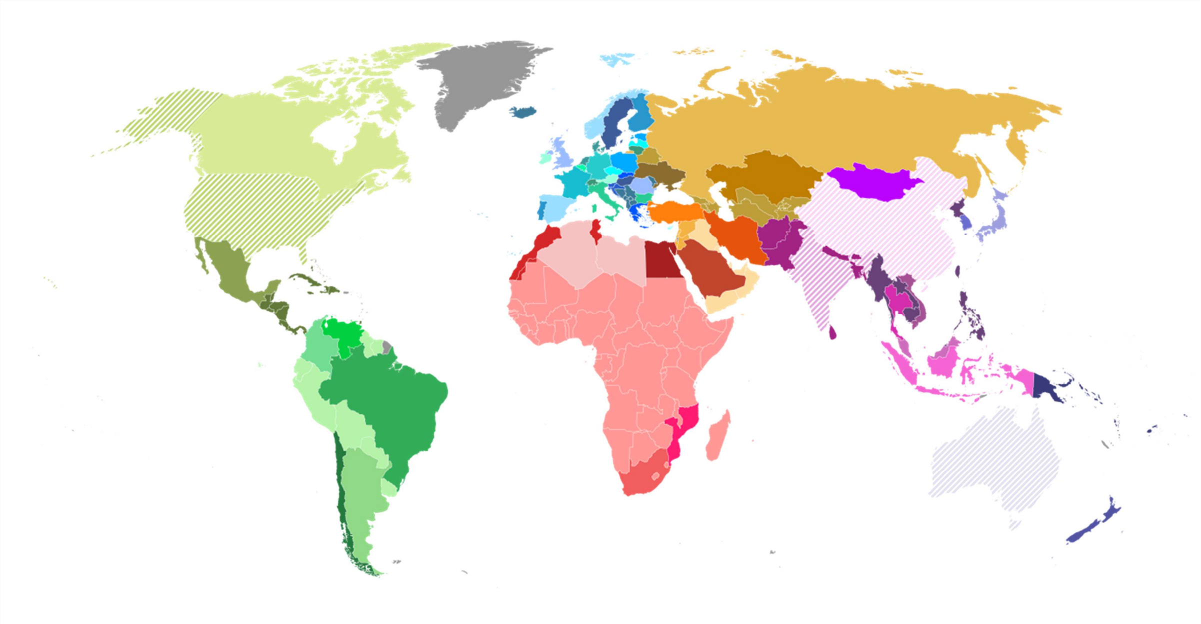
- for LNG suppliers, the marginal supply cost of all suppliers, taking into account the production cost and the transport cost to that market;
- for pipeline suppliers, the weighted average of supply costs, taking into account the production cost and the transport cost to that market, and an indexation to the evolution of the international oil price to reflect long-term contracts;
- in addition, an indicator of resource scarcity, based on the evolution of the reserve/production ratio of all supplies to that market.

Gas market prices are then grouped into three large continental markets for international gas prices – Asia, America and Europe-Africa – in order to reflect the inter-dependency of markets. These are the prices used as import prices for consuming regions.

5.2 Coal

Figure 29 shows the different coal producers (81) considered in the modelling.

Figure 29. POLES-JRC geographic breakdown for coal production



NB: The following countries are broken down into sub-national production regions: Australia (2 regions), China (4 regions), India (4 regions), United States (4 regions).

The coal supply module is based on three main sub-modules:

- key producers,
- demand,
- trade.

Coking coal and steam coal are differentiated but modelled in similar ways. A link between coking and steam coal modelling is implemented at the resource level, since both types of coal share the same resources in the model. Mining costs are differentiated between steam coal and coking coal so as to account for quality differences, while transport costs are common (all calculated in USD/t).

The resources are based on 'proved amount of coal in place' (WEC 2013a).

The price of coal includes both mining and transport costs.

The modelling of the mining cost captures both the evolving need and use of the production factors and the cost evolution of each of these factors: labour, energy use, materials use and others components (repairs, machinery, mining parts, tyres, explosives; including processing and additional administrative costs and taxes). It combines:

- an aggregated cost curve including:
- a long-term component reflecting changes in accessibility of the resource, geological conditions and a decrease in the energy content;
- a short-term component reflecting the utilisation rate of existing capacities;
- the evolution of the cost of the different factors is as follows:
- labour: income per capita;

- energy: price of oil and electricity to industry;
- materials use: energy price of steelmaking;
- other components: considered as remaining constant.

Transport costs are the sum of:

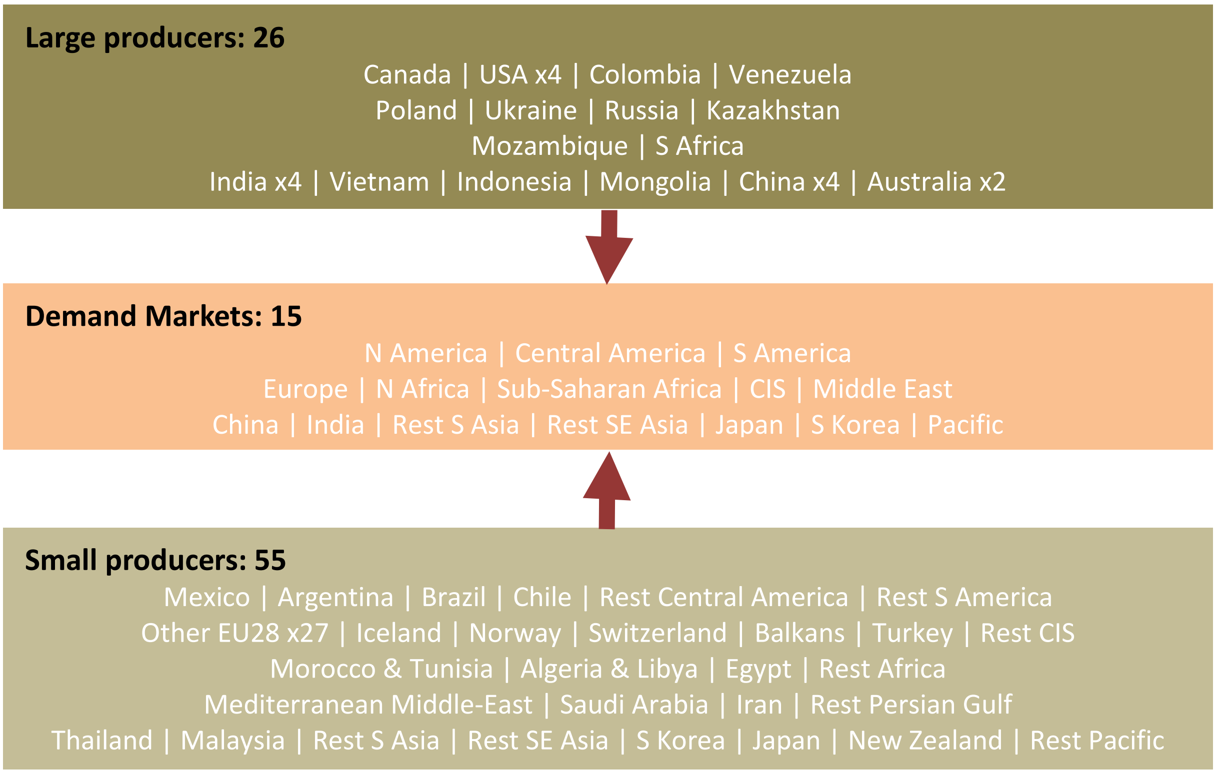
- inland transport costs from mining site to export terminal (rail);
- inland transport costs from export terminal to importer (rail);
- maritime transport costs from export terminal to importer: sum of port charges (port facilities, loading, unloading) and freight charges that depend on the distance from exporter to importer and on the price of maritime bunker fuel.

The functioning of the production and trade module is similar to that of gas (see Section 5.1.5).

Trade takes place between large producers (26 countries or regions) and demand markets (15 regional markets) (see **Figure 30**). Small producers (55) only produce for domestic consumption, based on domestic demand and coal prices (positive elasticity); their contribution decreases regional supply needs.

Coal trade (of steam coal and of coking coal) is calculated based on demand. The competition between coal producers for market shares in each importing market is driven by the total costs (mining and transport) with an elasticity and weighting factors allowing the historical trade matrix to be recreated.

Figure 30. Mapping of large coal producers and demand markets



NB: 'Rest' regions are adapted to the relevant singled-out producers; they are different from the energy demand and oil and gas production regions.

Traded volumes are adjusted through export capacities: for each large producer both the expansion of new capacities and the total supply capacity are capped, to reflect respectively bottlenecks in industrial organisation capabilities and resource management policy. The global need for new supply capacities is then allocated to each trade route in order to satisfy demand.

The resulting coal price for a demand market is the weighted average of the total costs of supply to that market.

Lignite remains a local resource, and its price is not affected by the coal market.

5.3 Biomass

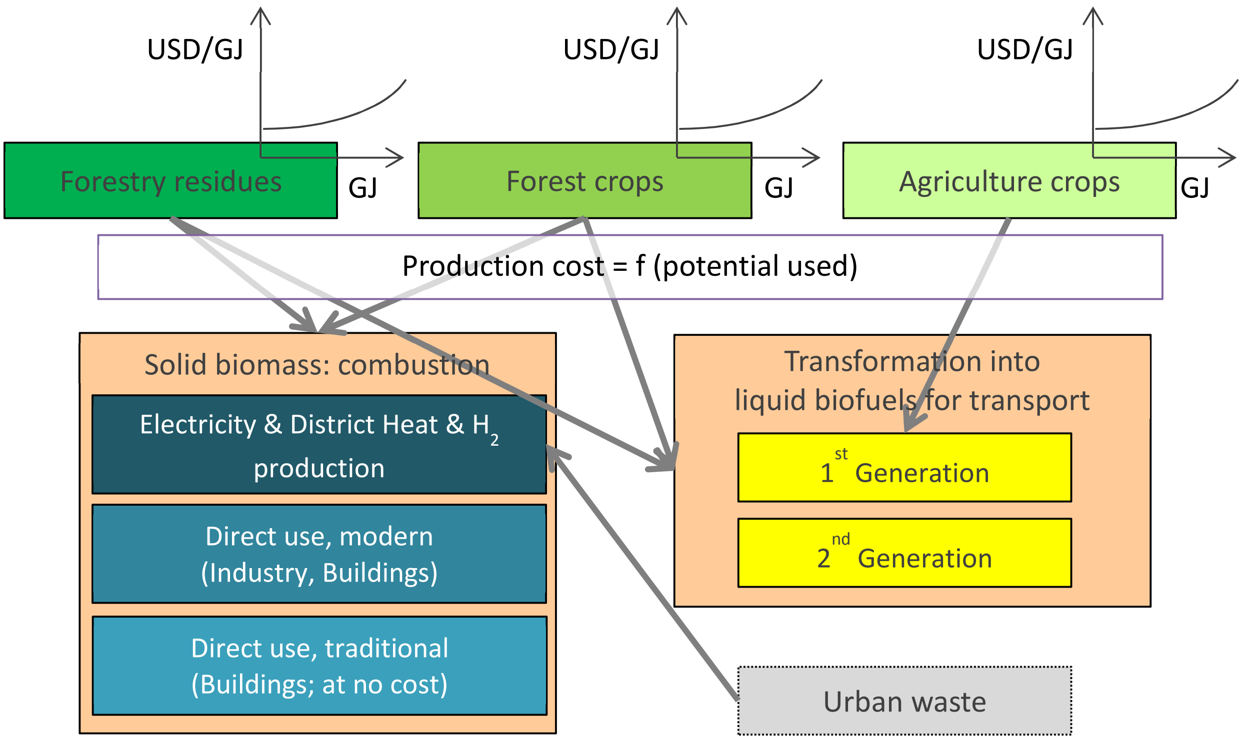
The model distinguishes three primary biomass resource types for energy uses. Each type is associated with an energy potential and a supply cost curve. They are:

- forest residues (cellulosic),
- short rotation energy crops (cellulosic),
- dedicated agriculture energy crops (non-cellulosic) for first-generation liquid biofuels.

For agriculture crops (used in first-generation liquid biofuels), the energy potential is derived from available area (assumed decreasing share of agricultural areas) and yield.

For cellulosic biomass (forest residues and short rotation crops, used in all other uses: heating, electricity, second-generation biofuel) the energy potential and the production cost curve come from the GLOBIOM model ([24]). An international price of cellulosic biomass is derived from the aggregation of regional cost curves.

Figure 31. Schematic representation of biomass flows in the POLES-JRC model

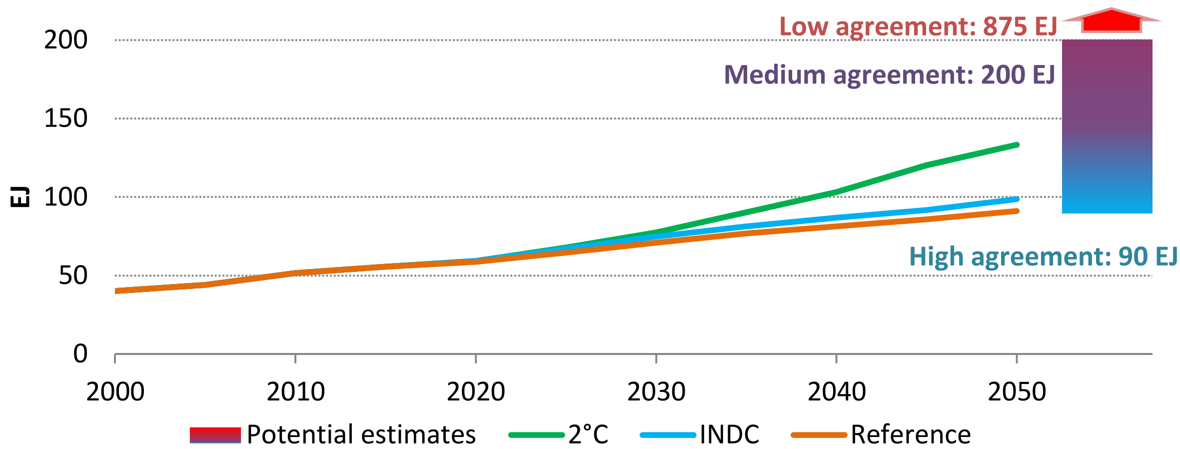


The domestic production of agriculture crops for energy purposes is determined by domestic needs for first-generation liquid biofuels production, considering the trade in liquid biofuels.

([24]) The cost curves integrate a carbon value dimension (see Havlik et al. 2014, IIASA 2016a).

The domestic consumption of cellulosic biomass is determined by needs for combustion and conversion into second-generation liquids. A competition takes place between domestic production and imports, comparing the local production cost and the international market price.

Figure 32. Biomass-for-energy production and potential, world



Sources: Biomass production: GECO 2016; potential estimate and qualification of agreement in literature: Creutzig et al. (2015).

Land use in POLES-JRC

The following land areas are identified:

— agricultural land: food production and energy crops,

— forests,

— built areas (evolves with urban population),

— inland water and deserts (fixed),

— other unused land, as the difference with total area.

Historical data are from FAO (FAO 2015) and evolution of agriculture and forest areas is according to GLOBIOM (IIASA 2016a).

5.4 Uranium

The conventional nuclear power technology in POLES-JRC corresponds to generic light water reactors using enriched uranium fuel (3.5 % U^{235} from about 0.7 % in natural uranium).

The price of nuclear fuel takes into account all costs within the nuclear fuel cycle from mining via enrichment to fabricating fuel rods (WISE 2016). A global cost-resource curve for mining natural uranium includes resources of up to 14.5 Mt of natural uranium (IAEA/OECD 2013) ([25]).

Mass flows of nuclear material and its interactions are implemented on a global level. This allows the tracking of the amount of high radioactive waste and depleted uranium (0.3 % U^{235}), which can be tapped as a resource for nuclear fuel by taking into account re-enrichment. The implementation of nuclear mass flows also allows further insights into the resource availability of uranium for nuclear power generation.

([25]) This comprises uranium resources in the categories identified, inferred and undiscovered resources according to the annual revised estimations of the International Atomic Energy Agency (IAEA) and OECD Nuclear Energy Agency (NEA).

Advanced nuclear design (fourth generation) using breeder technology is introduced from the middle of the century onwards. The advanced nuclear design breeds plutonium from fertile U^{238}, thus increasing the theoretical availability of nuclear fuel by two orders of magnitude. The interaction of nuclear fuel cycles for conventional and advanced nuclear design is taken into account.

5.5 Hydro potential

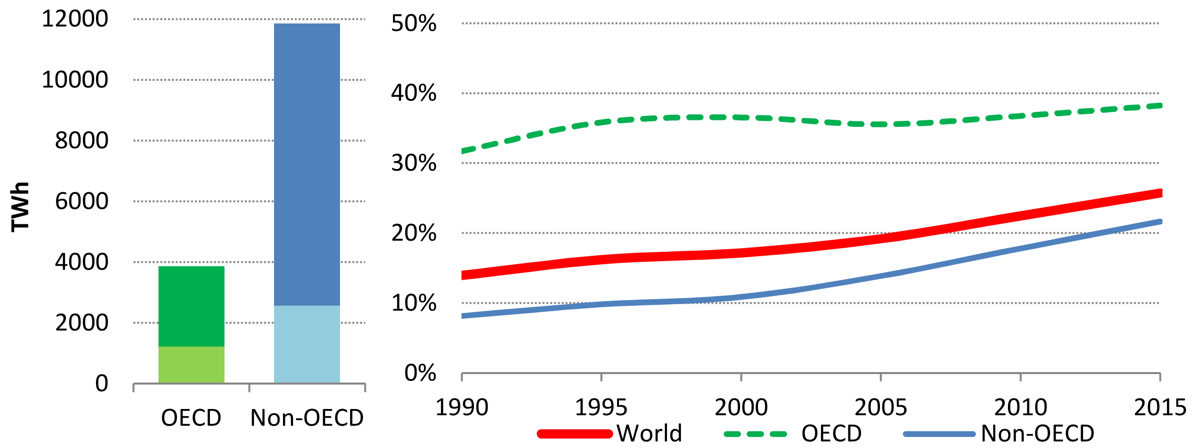
Three types of hydro power plants are modelled: large hydro (> 20 MW), small hydro (< 20 MW) and hydro pump and storage.

Yearly hydro power production is determined by capacity and load factor and is capped by a production potential that is detailed for large and small hydro (Enerdata 2017a).

The production profile is adjusted to account for storage needs (see section 4.1.3).

The model allows for soft linkage towards hydrological models to capture possible future change in rain patterns and consequent seasonal or yearly availability of water for hydroelectricity.

Figure 33. Hydroelectricity potential in 2015 (left) and % of potential used over 1990-2015 (right)



Source: IEA 2017a, Enerdata 2017a

5.6 Wind potential

Wind power production is determined from production profiles (see section 4.1.3). Its deployment is determined by costs and potential.

Onshore and offshore wind potential is derived from a detailed technological representation. The wind potential is derived from NREL (2013) using the following factors.

- The **meteorological potential** ([26]), in available area (km^2) where the mean wind over time exceeds a certain value at 10 m height, is aggregated into six classes according to wind speeds and distance from the shore ([27]).
- **Exclusion factors** are applied, due to land-use (e.g. marine protected areas, share of forest area) and social constraints (dependent on population density

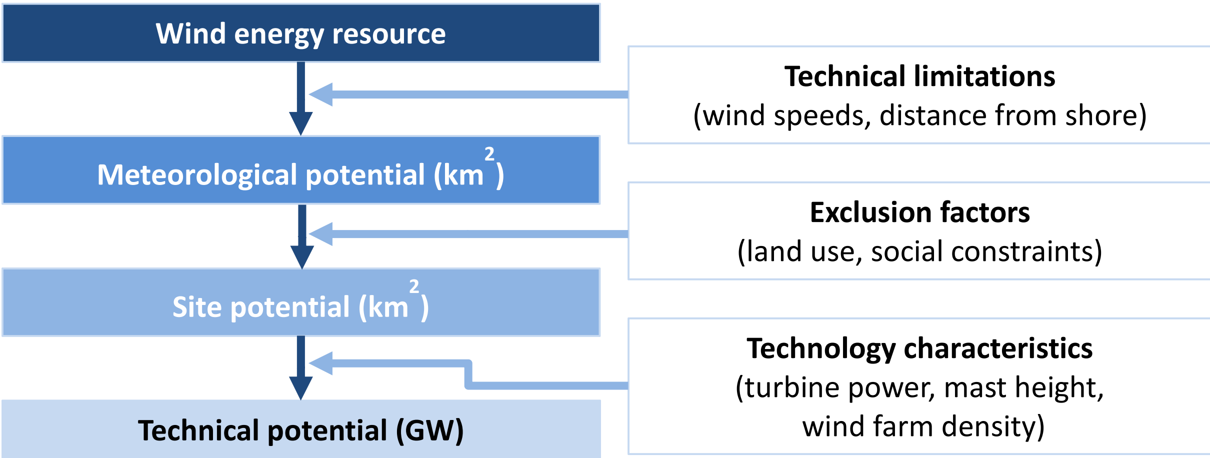
([26]) Wind atlases for onshore and offshore are elaborated using wind resource models like WAsP (Wind Atlas Analysis and Application Program), which computes the annual mean wind speed for thousands of grid points (van Wijk et al. 1993: Matthies et al. 1993)

([27]) Classes correspond to US wind energy classes (see NREL 2013): C1-C2 (not suitable for wind power generation), C3 (lower energy content, 5.35 m/s), C4 (intermediate, 5.8 m/s) and C5-C7 (most energetic winds, 6.7 m/s and above). Aggregation for onshore: C3; C4; C5-C7. Aggregation for offshore: C5-C7 at 0-10km distance; C3-C4 at 0-10km distance; C5-C7 at 10-30km distance.

and on income per capita). In addition, to account for other types of constraints (minimum distance to heritage sites, NIMBY-type opposition etc.), the installation potential of wind onshore is capped at 0.1 MW/km^2 on average in the country/region.

- Wind machine and wind field characteristics provide the **technical potential**: it is obtained from the power rating per turbine and a wind machine density in wind farms, which depends on the turbine spacing and the diameter of the turbine.

Figure 34. Schematic representation of the wind potential treatment in POLES-JRC



The potential (W) is then implemented as a limitation (Wh) to wind capacities in the model using load factors (site-specific starting point with historical data). The average wind capacity load factor evolves as new installations join the total capacities. The load factor for new installations is derived from a function of the wind power density at hub height, which grows over time.

5.7 Solar potential

5.7.1 Solar power plant potential

Solar power plants' production is determined from production profiles (see section 4.1.3). Their deployment, in competition with centralised power production means, is determined by costs and potential.

The potential of solar power plants (concentrated solar, with and without storage, and utility-scale PV) relate to available surface for constructing such facilities; they develop in desert areas and a share of grasslands. The potential to produce per surface relates to solar irradiation, taking into account geographical and environmental factors.

The surface on which power plants can be deployed is related to a solar power supply curve, which provides the load factor as a function of the percentage of used surface (Pietzcker et al. 2014). The potential surface is shared between technologies according to expected power needs.

The resulting load factor is an input in the electricity sector.

5.7.2 Solar distributed photovoltaic potential

Distributed PV power production is determined from production profiles (see section 4.1.3). Its deployment, in competition with grid electricity and other decentralised technologies in buildings, is determined by costs and potential.

Distributed PV is assumed to be installed on rooftops of dwellings and service buildings. The potential of distributed PV is estimated as share of total rooftop surface and an average unit production (kWh/m²) which is derived from average solar irradiation and technical efficiency.

The share available for distributed PV considers that:

- only a portion of the actual surface is available due to characteristics of the buildings (orientation, type of rooftop etc.), construction norms or social factors;
- PV competes with solar thermal installations for rooftop surface.

5.7.3 Solar thermal potential

Solar thermal heat production (i.e. solar collectors) follows a return on investment logic to address space and water heating needs (see Section 4.2 Heat production).

The evolution of the potential is analogously modelled to distributed PV (with an average unit production given in toe/m^2).

5.8 Geothermal electricity

World geothermal potential is set at 50 GW, in the lower end of the range provided by the World Energy Council (WEC 2016) of 35-200 GW. The regional distribution depends on installed capacities and identified projects.

6 Emissions

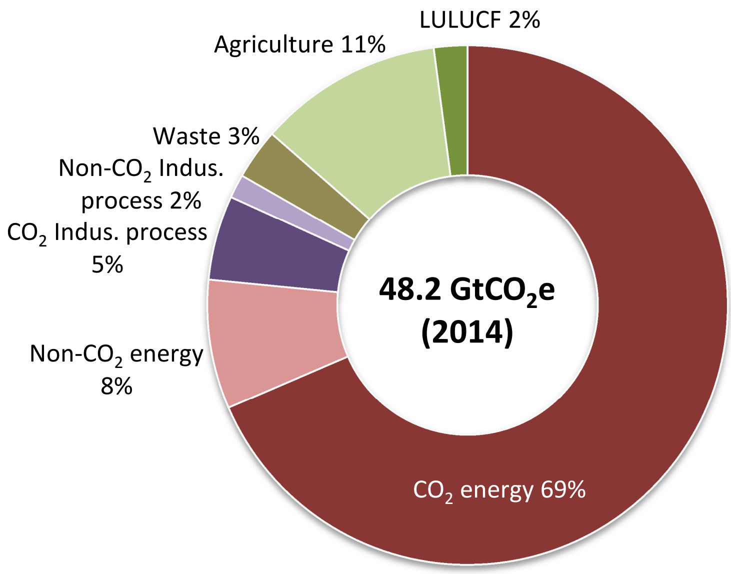
6.1 Greenhouse gases

6.1.1 Modelling principles and marginal abatement cost curves

The GHGs emitted by human activities that are covered by the model are the six ones identified in the UNFCCC Kyoto Protocol: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride (SF_6).

GHGs are emitted in a range of economic activities. Energy and industry (CO_2 and non-CO_2 combined), which form the focus of the model, represent a very important share of total emissions (83 % in 2014); CO_2 emissions from the energy sector (i.e. combustion of fuels) are the most important single contributor (69 % in 2014).

Figure 35. World greenhouse gas emissions per activity type, 2014



Source: UNFCCC 2015

NB: Waste is non-CO_2; agriculture is non-CO_2; LULUCF is CO_2.

For CO_2 emissions from fossil fuel combustion, emission volumes are obtained directly from the use of individual fossil fuels with an emission factor.

CCS technology can develop both in power generation and in industry sectors.

For other GHG emissions from energy and industrial processes, the projection is based on:

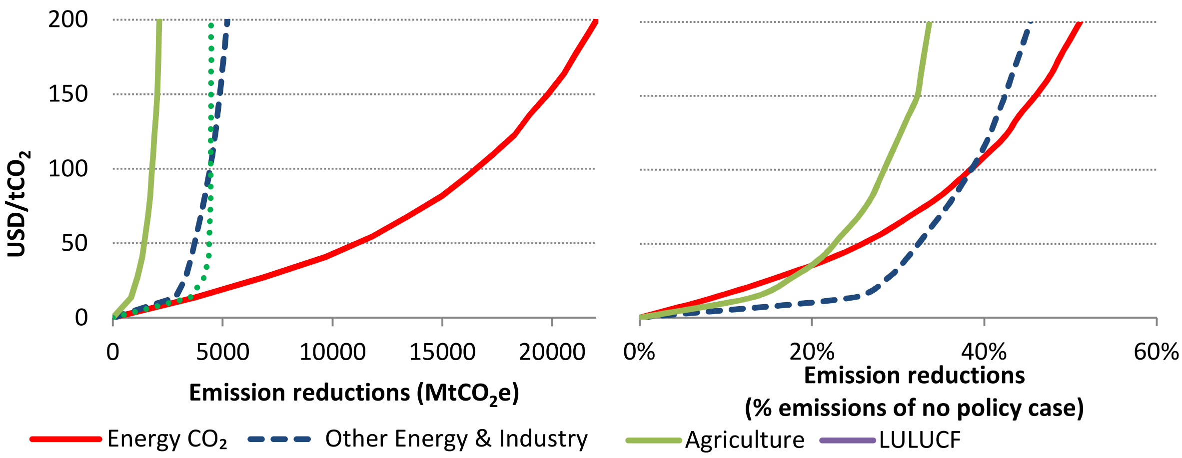
- a sector-specific economic driver (sectoral value added, energy production or energy consumption);
- a trend capturing technology changes;
- a marginal abatement cost curve (MACC) that describes the interaction with climate mitigation policies; MACCs comes from the EPA (2013).

For GHG emissions from AFOLU ([28]), baseline emissions and mitigation potential are derived from the specialised GLOBIOM model (IIASA 2016a).

Global warming potentials (GWPs ([29])) are applied to non-CO_2 greenhouse gases to convert emissions to CO_2-equivalent.

Figure 36 gives as an illustration the aggregated MACCs of the main sectors at world level, which sums the country and regional level MACCs.

Figure 36. Marginal abatement cost curves (all gases, all sources, world, 2030) — volume (left) relative to baseline emissions (right)



Sources: Energy CO_2 from POLES-JRC, other GHGs from energy and industry from EPA (2013), agriculture and LULUCF from GLOBIOM (IIASA 2016a). GWPs from SAR (IPCC 1996a).

The model allows GHG emissions trading markets to be represented via the comparison between emissions resulting from equalisation of marginal abatement costs and emission permits (or emission endowments).

6.1.2 Energy-related emissions

Energy-related emissions refer to GHG emissions where the primary driver is energy production or consumption. They consist in CO_2 emissions from fossil fuel combustion and non-CO_2 emissions from energy-related activities.

6.1.2.1 Combustion-related emissions

CO_2 emissions from the combustion of fossil fuels are the most important GHG source (about 64 % of the global total GHG emissions in 2014).

Emissions are calculated from energy balances by applying a fuel-specific emission factor according to IPCC guidelines (IPCC 2006).

CO_2 emissions from the combustion of solid biomass are not accounted for, with the assumption that the chain of biomass-for-energy production is carbon neutral; however, an emission factor was included in order to account for carbon captured when biomass is used in CCS. Similarly, the combustion of liquid biofuels is considered to be carbon neutral (CO_2 is only emitted due to the energy use in their production process, which is captured endogenously); however, an emission factor can be used for the calculation of vehicle emission standards.

([28]) AFOLU: agriculture, forestry and land use.
([29]) GWP as defined in the IPCC assessment reports.

A finer level of detail is given for emissions from oil products in transport, where specific carbon emission factors have been introduced.

Table 10. CO_2 emission factors

Fuel/sector	Emission factor (tCO_2/toe)
Oil	3.17
Gas	2.34
Coal	3.98
Oil: domestic and international air transport	2.93
Oil: international maritime bunkers	3.19
Biomass (*)	4.19

(*) Biomass and its products are considered as carbon-neutral in the emissions balances.

Total emissions balances take into account carbon that is captured in CCS (in power plants, synthetic fuel production, hydrogen production and industry) and the uptake of carbon in steelmaking from coking coal.

6.1.2.2 Non-CO_2 energy-related emissions

These emissions are captured by an emission intensity (with a MACC) applied to the relevant activity (see summary below). The following GHG emissions relate directly to energy production, transport or consumption.

- CH_4 emitted by the fossil fuel sector evolves with the projected production and transport of fossil fuels:
  - processes in the oil industry (exploration, production and refining, venting and flaring);
  - upstream processes of natural gas production;
  - transmission and distribution in the natural gas sector;
  - underground mining and surface coal mining.
- CH_4 and N_2O as by-products of incomplete combustion processes are accounted for in:
  - the electricity and industrial sectors;
  - the residential and service sectors;
  - the transport sector.
- SF_6 is used, and emitted, in electricity transmission and distribution for insulation and current interruption.

6.1.3 Process emissions in industry

These GHG emissions are the result of chemical or physical reactions other than combustion and where the primary purpose of the industrial process is not energy production.

- In the *iron and steel sector*: CO_2 is emitted from the use of coal and coking coal in the iron ore reduction process.
- In the *non-metallic mineral industry* (cement, glass, ceramics): CO_2 is emitted when carbonates contained in the raw material are thermally decomposed in the process.
- In the *chemical industry*: CO_2 process emissions occur in some processes (e.g. ammonia production), while N_2O emissions take place in the production of nitric acid and adipic acid.

- A variety of HFCs are emitted from air conditioning, refrigeration, foams, solvents and other processes.
- PFCs are emitted in the production of *primary aluminium* and other industrial processes (semiconductors, solvents etc.).
- SF_6 is emitted in magnesium refining and semiconductor processing.

The projected emissions evolve with the sectoral value added, a technological trend and the abatement potential in case of GHG mitigation policy.

6.1.4 Waste

CH_4 is emitted from solid waste disposal (municipal and industrial origin) and wastewater treatment. N_2O is generated from processing wastewater due to the de/nitrification processes of the nitrogen present.

The main drivers of emissions increases are urban population and industrial value added, a technological trend and the abatement potential in case of GHG mitigation policy.

6.1.5 Agriculture, forestry and other land use (AFOLU)

The agriculture sector is a source of CH_4 and N_2O emissions. CH_4 is emitted by various activities such as enteric fermentation, manure management, soils and rice cultivation. N_2O is emitted from manure management and soils (fertilisers).

LULUCF emissions include CO_2 emissions from net forest conversion (CO_2 emissions by deforestation and CO_2 sinks by afforestation) and CO_2 emissions from other forestry and land use.

Projections of AFOLU emissions evolve based on look-up data from the GLOBIOM model (Havlik et al. 2014, IIASA 2016a) (curves that take into account the price of carbon and the price of biomass in order to determine biomass use and AFOLU emissions).

6.1.6 Greenhouse gas coverage summary

Table 11 provides a summarised view of the GHG emissions flows in the model.

Table 11. Greenhouse gas emission sources

Sector	Category	GHG	Emission activity	Modelling driver
Energy	Fuel combustion	CO_2	Burning of fossil fuel	Fossil fuel combustion
	Oil and gas sector	CH_4	Production, transmission and distribution	Oil and gas production Gas transport and use
	Coal production	CH_4	Underground and surface mining	Coal production (underground and surface differentiated)
	Power and heat, transport, residential	N_2O CH_4	Combustion by-products	Sectoral final energy consumption
	Power systems	SF_6	Transmission and distribution	Electricity production
Industrial processes	Steel	CO_2	Iron ore reduction	Tonnes of steel using thermal processes
	Non-metallic minerals	CO_2	Carbonate decomposition	Non-metallic minerals industry value added
	Chemistry	CO_2 N_2O	Steam reforming Nitric and adipic acid	Chemicals industry value added
	Aluminium	PFCs	Primary aluminium Semiconductor and PV	'Other' industry value added
	Magnesium, semiconductors	SF_6	Magnesium refining, Semiconductor and PV	Industry value added
	Residential, services, transport	HFCs	Air conditioning, refrigeration aerosols, foams, solvents	Industry value added
Waste	Waste	CH_4 N_2O	Solid waste and wastewater Burning of waste	Urban population (urban waste) Industry value added (industrial waste)
Agriculture, forestry and other land use (AFOLU)	Agriculture	CH_4 N_2O	Enteric fermentation, manure management, soils and rice cultivation	Default emission profile from GLOBIOM, influenced by the biomass price as a proxy for land use activities.
	Forestry and land use	CO_2	Deforestation, afforestation, other forestry and land use	Biomass price (derived from GLOBIOM cost curves) as a proxy for forestry activity and other land use

6.2 Pollutant emissions

The coverage of this dimension in the POLES model is done through a linkage towards the specialist GAINS model that provides emission factors per pollutant and sector fuel (see IIASA 2015 and IIASA 2016a) that are then mapped to POLES series.

Symmetrically, the POLES-JRC energy balances have also been used as inputs to the GAINS model to derive the evolution of air pollutant emissions (see Rafaj et al. 2013).

6.2.1 Pollutants covered

The following air pollutants and short-lived climate forcers are represented in the model:

- SO_2 : sulphur dioxide,
- NO_x : nitrogen oxides,
- (NM)VOCs : non-methane volatile organic compounds,
- CO : carbon monoxide,
- BC : black carbon,
- OC : organic carbon, which can be converted into organic matter (OM),
- $PM_{2.5}$: particulate matter of 2.5 µm, the sum of BC, OM and other $PM_{2.5}$,
- PM_{10} : particulate matter of 10 µm, the sum of $PM_{2.5}$ and other PM_{10}
- NH_3 : ammonia.

Pollutants resulting from the interaction of the above species with other gases (precursors) such as ozone are not modelled

6.2.2 Emission calculation

The pollutant emissions are calculated as the product of activity and the emissions intensity factor (specific for each pollutant and sector).

The pollutant emissions flows in the model are listed below, with their corresponding activity indicators, totalling 48 flows per pollutant.

Table 12. Pollutants considered with emission factors as direct inputs

Sector	Source	Activity indicator
Industry	Biomass	Biomass in industry
	Coal	Coal in industry (excluding coking coal)
	Gas	Gas in industry (excluding non-energy uses)
	Oil	Oil in industry (excluding non-energy uses)
	Steelmaking	Tonnes of steel
Buildings	Biomass	Biomass in residential and services
	Coal	Coal in residential and services
	Gas	Oil in residential and services
	Oil	Gas in residential and services
Transport	Coal	Coal in transport (rail)
	Gas	Gas use in transport
	Diesel	Diesel used in road transport
	Gasoline	Gasoline used in road transport
	Oil	Oil products in non-road, non-air transport
	Oil	Oil products in domestic air transport
	Oil	Oil products in maritime bunkers
	Oil	Oil products in international air bunkers
Agriculture	Oil	Oil products in agriculture
Power generation	Biomass	Biomass inputs in power generation (*)
	Coal	Coal inputs in power system for capacity historically installed (conventional coal)
	Coal	Coal inputs in newly installed power capacity (conventional coal)
	Coal	Coal inputs in newly installed power capacity (advanced coal) (*)
	Gas	Gas inputs in power generation (*)
	Oil	Oil inputs in power generation
Other energy transformation	Oil	Losses in refineries
	Oil	Oil and gas production (on-site own consumption)

(*) An additional flow is considered when associated to CCS, where a multiplying emission coefficient is applied to the coefficient without CCS.

Table 13. Pollutants considered with emission factors recalculated from historical data

Sector	Source	Activity indicator
Industrial production	Cement	Total energy in non-metallic minerals industry
	Chemicals	Total energy in chemicals industry
	Fertilisers	Total energy in chemical feedstocks industry
	Solvents	Value added of chemicals industry
	Other combustion	Oil in other industry
	Other processes	Total energy in other industry
Buildings	Other/unattributed	Oil in residential and services
Surface transportation	Other/unattributed	Oil in road transport
Agriculture	Non-energy	N_2O emissions from agriculture
Energy transformation	Other/unattributed	Oil inputs in power generation
Other energy transformation	Oil	Oil auto-consumption of the energy transformation sector and oil T & D losses
	Gas	Gas auto-consumption of the energy transformation sector and gas T & D losses
	Coal	Coal auto-consumption of the energy transformation sector and coal T & D losses
Fires	Forest fires	None (trend)
	Savannah fires	None (trend)
	Peat fires	None (trend)
	Agricultural waste burning	None (trend)
Waste	All	Urban population
Other	Other/unattributed	Population

The future evolution of the emissions intensity factors are based on IIASA (2016a). Their future evolution moves within boundaries defined by current legislation and maximum technical feasible reductions (as defined by GAINS scenarios — see IIASA 2015).

The default behaviour in the model reflects current legislation adopted by countries around the world in the medium term ([30]). In the longer term, it is assumed that technologies and air pollution policies diffuse across world regions at different speeds depending on per capita income. This results in a 'middle-of-the-road' trajectory of emission intensity factors, between factors frozen at their last historical point and factors corresponding to the best technology expected to be available in the future ([31]). Further reductions can be achieved as co-benefits of a climate policy, caused by the reduction of fossil fuel consumption.

([30]) For example, the 2030 objectives of the EU's 'Clean air programme' (Directive 2016/2284/EU), see: http://ec.europa.eu/environment/air/pollutants/ceilings.htm

([31]) These assumptions are compatible with the socio-political definition of the SSP2 scenario. For emission intensity factors going beyond those derived from current legislation, their evolution by country group and across time is similar to the method in Rao et al. (2016).

7 Energy and climate policy implementation

The model allows variant scenarios to be developed and policies to be translated into quantitative modelling inputs, by sector and region, by 2050 in a standard configuration and up to 2100 for long-term mitigation strategies.

It can also be connected to specialised models to expand the assessment towards other policy areas (e.g. macroeconomics, land use, water, etc.).

The following dimensions can be considered.

Socioeconomic context

- Population, economic growth, income, urbanisation
- Discount rates on energy investments
- Lifestyle analysis (dwellings and mobility)

Energy resources

- Assumptions on ultimately recoverable resources or accessible resources
- Indigenous fossil fuel resources management

Climate and energy policies

Climate and environmental policies

- Cap on all or selected GHG emissions
- Pricing of all or selected GHG emissions

Technology support policies

- Technology availability, costs and learning rate assumptions
- Technology purchase: subsidies and low interest rate loans
- Power-specific policies: feed-in tariffs or premiums
- Transport-specific policies: development of infrastructure for alternative vehicle technologies

Energy consumption policies

- Fiscal policy on energy fuels to assess the impact on energy consumption and energy independence
- Subsidy on energy fuel
- White certificate to spur energy efficiency
- Building-specific policies: renovation rates of buildings, development of insulation
- Transport-specific policies: fuel and emission standards, modal shift.

8 Data

The model uses annual historical data to initialise the projections, typically for the period 1980 to the latest data available (for most series: up to the year preceding the current year).

Due to the recursive simulation nature of the model, projected data presents a high degree of continuity with historically observed data.

The historical data is used to derive parameters that enhance the model's capability to take into account country and sector specificities in investment and consumption behaviour: elasticity to price or activity, autonomous technological trends and non-cost weighting parameter in the competition for new equipment or fuels.

The following information is needed:

- socioeconomic and activity variables: population (total, urban vs. rural), GDP, sectoral value added, mobility, number of dwellings, surfaces, etc.,
- energy balances: final demand, transformation, supply,
- energy prices and taxes,
- energy reserves and resources,
- GHG emissions.

8.1 Economic activity

Data for EU population and activity comes from Eurostat for history (Eurostat 2015) and the EU Ageing Report for projections (European Commission 2015).

Population data for non-EU countries and regions from the UN (UN 2015) and the EU Ageing Report. Historical GDP and value added come from the World Bank (WB 2016), while projections of GDP growth come from the IMF (for the next 5 years, IMF 2016) and the OECD for the longer term (OECD 2014).

Information on sectoral activity variables (mobility, surfaces, dwellings, industrial production, etc.) come from the IRF (2014), UIC (2014), ICAO (2015), Unctad (2015), WSA (2015), World Bank (2016), Enerdata (2015a), Enerdata (2015b) and national sources.

8.2 Energy

Data for energy balances and prices comes from Enerdata (2015a), with additional information from:

- Eurostat: energy balance of EU countries (Eurostat 2015);
- IEA: energy balance for non-EU countries, energy prices (IEA 2015a, IEA 2015b);
- Platts: power plant capacities (Platts 2015);
- BP: oil and gas reserves and production (BP 2015);
- Specialist studies for energy resources: fossil fuels (BGR 2015, USGS 2013, Schenk 2012), hydro (WEC 2016b), wind (NREL 2013), solar (Pietzcker et al. 2014), bioenergy (IIASA 2016a), geothermal (WEC 2016a);
- Specialist studies for technology costs: the JRC (2014b), WEC (2013b), IRENA (2015), IEA (2014).

8.3 Greenhouse gas emissions

Historic emissions for CO_2 emissions from combustion processes are derived from energy balance data.

For UNFCCC Annex I countries, all other GHG historical emissions are from UNFCCC inventories (UNFCCC 2015).

For Non-Annex I countries, emissions from energy, industry and agriculture are from the EDGAR database (European Commission JRC 2011, 2014a), while CO_2 emissions from LULUCF refer in principle to FAOSTAT (FAO 2015) and for some countries to national inventories (Brazil, Mexico). For Indonesia the LULUCF CO_2 emissions from FAOSTAT are complemented by emissions from peat fires from EDGAR data ([32]).

Certain additional emissions time series are included in the model to determine specific aspects of energy/emissions accounting: total CO_2 emissions of the road transport sector, total CO_2 emissions of the steel sector and process CO_2 emissions of the steel sector.

8.4 Air pollutants

Sources for historical air pollutant emissions are:

- GAINS ECLIPSE v5a (IIASA 2015) for most sectors;
- estimates from emission factors using IPCC emissions guidelines (IPCC 1996b) and AERO2k (33) for air transport emissions;
- EDGAR v4.2 (European Commission JRC 2011) for fires;
- national sources to complement.

Information on future emissions and future emissions factors is from:

- GAINS ECLIPSE v5a for most sectors;
- AERO2k for air transport;
- UNEP report for CCS technologies;
- national sources for policies.

8.5 Summary

Table 14 provides a synthetic view of the data sources used in the POLES-JRC model.

([32]) Fires introduced as an exogenous series to complete country emissions; can be modified to reflect policy objectives.

([33]) FP6 project; https://www.researchgate.net/publication/224796937_AERO2k_Global_Aviation_Emissions_Inventories_for_2002_and_2025; http://www.aerodays2006.org/sessions/A_Sessions/A1/A13.pdf

Table 14. Data sources in POLES-JRC

Series		Historical data	GECO projections
Population		UN, Eurostat	UN (medium fertility)
GDP, growth		World Bank	European Commission, IMF, OECD (see Dellink et al. 2014)
Other activity drivers	Value added	World Bank	POLES-JRC model
	Mobility, vehicles, households, tonnes of steel	Sectoral databases	
Energy resources	Oil, gas, coal	BGR, USGS, WEC, sectoral information	
	Uranium	IAEA/OECD	
	Biomass	GLOBIOM model	
	Hydro	Enerdata	
	Wind, solar	NREL, Pietzcker et al. (2014)	
Energy balances	Reserves, production	BP, Enerdata	
	Demand by sector and fuel, transformation (including. power), losses	Enerdata, IEA	
	Power plants	Platts	
Energy prices	International prices, prices to consumer	Enerdata, IEA	POLES-JRC model
GHG emissions	Energy CO_2	Derived from POLES-JRC energy balances	POLES-JRC model
	Other GHG Annex 1	UNFCCC	POLES-JRC model, GLOBIOM model
	Other GHG Non-Annex 1 (excl. LULUCF)	EDGAR	POLES-JRC model, GLOBIOM model
	LULUCF Non-Annex 1	National inventories, FAO	POLES-JRC model, GLOBIOM model
Air -pollutant emissions		GAINS model, EDGAR, IPCC, national sources	GAINS model, national sources
Technology costs		POLES-JRC learning curves based on literature, including but not limited to: JRC, WEC, IEA Technology Roadmaps, TECHPOL database(*)	

(*) Developed in several European research projects: SAPIENT, SAPIENTIA, CASCADE MINTS.

9 Conclusions

This model documentation informs of the main characteristics of the POLES-JRC model as of 2018. The latest modelling upgrades and changes are therefore included. The objective is to document the model used for producing the GECO report of 2018.

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Selected research projects ([34])

In the following projects, research versions of the POLES model were used:

- CD-links
- ADVANCE (Advanced Model Development and Validation for Improved Analysis of Costs and Impacts of Mitigation Policies), for DG Research (FP7), 2013-2016. http://cordis.europa.eu/project/rcn/104887_en.html, http://www.fp7-advance.eu/
- AMPERE (Assessment of Climate Change Mitigation Pathways and Evaluation of the Robustness of Mitigation Cost Estimates), for DG Research (FP7), 2011-2013. http://cordis.europa.eu/project/rcn/98809_en.html, http://ampere-project.eu/
- EMF27 (Energy Modelling Forum 27: Global Model Comparison Exercise), coordinated by Stanford University, 2010-2013. http://emf.stanford.edu/projects/emf-27-global-model-comparison-exercise
- ADAM (Adaptation and Mitigation Strategies), for DG Research (FP6), 2006-2009. http://cordis.europa.eu/project/rcn/78409_en.html. Final report: http://www.cambridge.org/es/academic/subjects/earth-and-environmental-science/environmental-policy-economics-and-law/making-climate-change-work-us-european-perspectives-adaptation-and-mitigation-strategies
- MENGTECH (Modelling of Energy Technologies Prospective in a General and Partial Equilibrium Framework), for DG Research (FP6), 2006-2008. http://cordis.europa.eu/project/rcn/75100_en.html
- WETO-H2 (World Energy Technology Outlook — 2050), for DG Research (FP6), 2004-2005. http://cordis.europa.eu/project/rcn/73908_en.html. Final report: http://bookshop.europa.eu/en/world-energy-technology-outlook-pbKINA22038/
- CASCADE MINTS (CAse Study Comparisons And Development of Energy Models for INtegrated Technology Systems), for DG Research (FP6), 2004-2006. http://cordis.europa.eu/project/rcn/73909_en.html
- SAPIENTIA (Systems analysis for progress and innovation in energy technologies for integrated assessment), for DG Research (FP5), 2002-2004. http://cordis.europa.eu/project/rcn/64924_en.html
- SAPIENT (System analysis for progress and innovation in energy technologies), for DG Research (FP5), 2000-2002. http://cordis.europa.eu/project/rcn/51184_en.html

([34]) For a complete list of publications, see: http://ec.europa.eu/jrc/poles/publications

List of abbreviations and definitions

Acronyms and definitions

AFOLU	agriculture, forestry and land use
CCS	carbon capture and storage
CHP	combined heat and power
CNRS	Centre national de la recherche scientifique
DG	directorate-general (European Commission)
EDGAR	Emission Database for Global Atmospheric Research
E & P	exploration and production (fossil fuels)
EOR	enhanced oil recovery
EPA	Environmental Protection Agency (United States)
EROI	energy return on investment
FAO	UN Food and Agriculture Organisation
GDP	gross domestic product
GECO	Global Energy and Climate Outlook (JRC report)
GHG	greenhouse gas
GWP	global warming potential
IAEA	International Atomic Energy Agency
ICE	internal combustion engine
ICT	information and communication technology
IEA	International Energy Agency
IEPE	Institut d'Economie et de Politique de l'Energie
IIASA	International Institute for Applied Statistical Analysis
IMF	International Monetary Fund
IMO	International Maritime Organisation
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
ISIC	International Standard Industrial Classification
JRC	Joint Research Centre (European Commission)
LNG	liquefied natural gas
LR	learning rate
LULUCF	land use, land use change and forestry
MACC	marginal abatement cost curve
NEA	Nuclear Energy Agency
NGL	natural gas liquids
NMM	non-metallic minerals
NREL	National Renewable Energy Laboratory (United States)
O & M	operation and maintenance

OECD	Organisation for Economic Cooperation and Development
OPEC	Organisation of the Petroleum Exporting Countries
PPP	purchasing power parity
PV	solar photovoltaic
R/P	ratio of reserves over production
SSP	shared socioeconomic pathway
T & D	transmission and distribution
UNFCCC	United Nations Framework Convention on Climate Change
VRE	variable renewable energy source
WEC	World Energy Council

Chemical species

BC	black carbon
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
HFC	hydrofluorocarbon
NH_3	ammonia
NO_x	nitrogen oxide
N_2O	nitrous oxide
OC	organic carbon
OM	organic matter
PFC	perfluorocarbon
PM	Particulate matter
SF_6	sulphur hexafluoride
SO_2	sulphur dioxide
(NM)VOC	(non-methane) volatile organic compound

Models

GAINS	Greenhouse Gas — Air Pollution Interactions and Synergies
GLOBIOM	Global Biosphere Management Model
GEM-E3	General Equilibrium Model for Economy — Energy — Environment
POLES	Prospective Outlook on Long-term Energy Systems

Country and regional codes

CIS	Commonwealth of Independent States
EU	European Union
EU-28	European Union of 28 Member States
G20	Group of Twenty
OECD	Organisation for Economic Cooperation and Development

OPEC	Organisation of the Petroleum Exporting Countries

Units

Energy

Bcm	billion cubic metres	
EJ	exajoule	1 000 000 000 000 000 000 J
Gtoe	billion tonnes of oil equivalent	1 000 000 000 toe
Mtoe	million tonnes of oil equivalent	1 000 000 toe

Electricity

GW	gigawatts	1 000 000 000 W
kW	thousand watts	1 000 W
kWh	thousand watt-hours	1 000 Wh
TWh	tera watt-hours	1 000 000 000 000 Wh
W	watts	

Emissions

$GtCO_2e$	giga-tonnes of CO_2-equivalent	1 000 000 000 tCO_2
tCO_2e	tonnes of CO_2-equivalent emissions	

Monetary units

USD	US dollars	
USD PPP	USD at purchasing power parity	
K USD	thousand dollars	1 000 USD
tn USD	trillion dollars	1 000 000 000 000 USD

Other

cap	capita	
Gm^2	billion square metres	1 000 000 000 m^2
Gtkm	billion tonne-kilometres	1 000 000 000 tkm
kcap	thousand capita	1 000 cap
km	kilometres	
t	metric tonnes	
tkm	tonne-kilometres	
pkm	passenger-kilometres	

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Annexes

Annex 1. ISIC classification of sectors in POLES-JRC

Using: International Standard Industrial Classification of All Economic Activities, Rev.4 ([35])

Building and services: G (45-47) I (55-56) J (58-63) K (64-66) L (68) M (69-75) N (77-82) O (84) P (85) Q (86-88) R (90-93) S (94-96) T (97-98) U (99)

Transport: Groups 491-492 and Divisions 50-53

Agriculture (covers fishing and forestry): Divisions 01-03

Industry:

- Iron and steel: Group 241 and Class 2431
- Chemicals: Divisions 20 and 21
  - Chemical feedstocks: part of Group 201
  - Plastics and rubber: part of Group 201
- Non-metallic minerals (cement, lime, glass, ceramics): Division 23
- Other industry (other manufacturing, mining and construction): Divisions 07; 08; 10-18; 22; 25-33; 41-43; Groups 099; Group 242 and Class 2432

Energy transformation:

- Power generation: Division 35
- Other energy transformation: Divisions 05, 06, 19, 36-39; Groups 091, 493

([35]) http://unstats.un.org/unsd/cr/registry/regcst.asp?Cl=27

Annex 2: Country mappings

Energy and emissions balances

54 individual countries + 12 regions

Table 15. List of 54 individual countries represented in POLES-JRC

Non-EU individual countries	EU-28 Member States
Argentina	Austria
Australia	Belgium
Brazil	Bulgaria
Canada	Croatia
Chile	Cyprus
China	Czechia
Egypt	Denmark
Iceland	Estonia
India	Finland
Indonesia	France
Iran	Germany
Japan	Greece
Malaysia	Hungary
Mexico	Ireland
New Zealand	Italy
Norway	Latvia
Russia	Lithuania
Saudi Arabia	Luxembourg
South Africa	Malta
South Korea	Netherlands
Switzerland	Poland
Thailand	Portugal
Turkey	Romania
Ukraine	Slovakia
United States	Slovenia
Vietnam	Spain
	Sweden
	United Kingdom

NB: Hong Kong and Macau are included in China.

Table 16. Country mapping for the 12 regions in POLES-JRC

Rest Central America	Rest Balkans	Rest Sub-Saharan Africa	Rest South Asia
Bahamas	Albania	Angola	Afghanistan
Barbados	Bosnia and Herzegovina	Benin	Bangladesh
Belize	Former Yugoslav Republic of Macedonia	Botswana	Bhutan
Bermuda	Kosovo	Burkina Faso	Maldives
Costa Rica	Moldova	Burundi	Nepal
Cuba	Montenegro	Cameroon	Pakistan
Dominica	Serbia	Cape Verde	Seychelles
Dominican Republic	**Rest CIS**	Central African Republic	Sri Lanka
El Salvador	Armenia	Chad	**Rest South East Asia**
Grenada	Azerbaijan	Comoros	Brunei
Guatemala	Belarus	Congo	Cambodia
Haiti	Georgia	Democratic Republic of the Congo	Laos
Honduras	Kazakhstan	Côte d’Ivoire	Mongolia
Jamaica	Kyrgyzstan	Djibouti	Myanmar/Burma
Nicaragua	Tajikistan	Equatorial Guinea	North Korea
NL Antilles and Aruba	Turkmenistan	Eritrea	Philippines
Panama	Uzbekistan	Ethiopia	Singapore
São Tomé and Príncipe	**Mediter. Middle East**	Gabon	Taiwan
St Lucia	Israel	Gambia	**Rest Pacific**
St Vincent and Grenadines	Jordan	Ghana	Fiji
Trinidad and Tobago	Lebanon	Guinea	Kiribati
Rest South America	Syria	Guinea-Bissau	Papua New Guinea
Bolivia	**Rest of Persian Gulf**	Kenya	Samoa (Western)
Colombia	Bahrain	Lesotho	Solomon Islands
Ecuador	Iraq	Liberia	Tonga
Guyana	Kuwait	Madagascar	Vanuatu
Paraguay	Oman	Malawi	
Peru	Qatar	Mali	
Suriname	United Arab Emirates	Mauritania	
Uruguay	Yemen	Mauritius	
Venezuela	**Morocco and Tunisia**	Mozambique	
	Morocco	Namibia	
	Tunisia	Niger	
	Algeria and Libya	Nigeria	
	Algeria	Rwanda	
	Libya	Senegal	
		Sierra Leone	

		Somalia	
		Sudan	
		Swaziland	
		Tanzania	
		Togo	
		Uganda	
		Zambia	
		Zimbabwe	

Oil and gas production

77 individual countries + 11 regions

(*): 41 exporters

Table 17. List of 77 individual oil and gas producing countries represented in POLES-JRC

Non-EU individual countries		EU-28 Member States
Algeria (*)	Mexico (*)	Austria
Angola (*)	Myanmar/Burma (*)	Belgium
Argentina (*)	New Zealand	Bulgaria
Australia (*)	Nigeria (*)	Croatia
Azerbaijan (*)	Norway (*)	Cyprus
Bolivia (*)	Oman (*)	Czechia
Brazil (*)	Pakistan (*)	Denmark
Brunei (*)	Peru (*)	Estonia
Canada (*)	Qatar (*)	Finland
Chile	Russia (*)	France
China (*)	Saudi Arabia (*)	Germany
Colombia (*)	South Africa	Greece
Ecuador (*)	South Korea	Hungary
Egypt (*)	Switzerland	Ireland
Gabon (*)	Thailand	Italy
Iceland	Trinidad and Tobago (*)	Latvia
India (*)	Turkey	Lithuania
Indonesia (*)	Turkmenistan (*)	Luxembourg
Iran (*)	Ukraine	Malta
Iraq (*)	United Arab Emirates (*)	Netherlands (*)
Japan	United States (*)	Poland
Kazakhstan (*)	Uzbekistan (*)	Portugal
Kuwait (*)	Venezuela (*)	Romania
Libya (*)	Vietnam	Slovakia
Malaysia (*)		Slovenia
		Spain
		Sweden
		United Kingdom (*)

Table 18. Country mapping for the 11 oil and gas producing regions in POLES-JRC

Rest Central America	**Rest Balkans**	**Rest Sub-Saharan Africa**	**Rest South Asia**
Bahamas	Albania	Benin	Afghanistan
Barbados	Bosnia and Herzegovina	Botswana	Bangladesh
Belize	Former Yugoslav Republic of Macedonia	Burkina Faso	Bhutan
Bermuda	Kosovo	Burundi	Maldives
Costa Rica	Moldova	Cameroon	Nepal
Cuba	Montenegro	Cape Verde	Seychelles
Dominica	Serbia	Central African Republic	Sri Lanka
Dominican Republic	**Rest CIS (*)**	Chad	**Rest South East Asia**
El Salvador	Armenia	Comoros	Cambodia
Grenada	Belarus	Congo	Laos
Guatemala	Georgia	Democratic Republic of the Congo	Mongolia
Haiti	Kyrgyzstan	Côte d'Ivoire	North Korea
Honduras	Tajikistan	Djibouti	Philippines
Jamaica	**Mediter. Middle East**	Equatorial Guinea	Singapore
Nicaragua	Israel	Eritrea	Taiwan
NL Antilles and Aruba	Jordan	Ethiopia	**Rest Pacific**
Panama	Lebanon	Gambia	Fiji
São Tomé and Príncipe	Syria	Ghana	Kiribati
St Lucia	**Rest of Persian Gulf**	Guinea	Papua New Guinea
St Vincent and Grenadines	Bahrain	Guinea-Bissau	Samoa (Western)
Rest South America	Yemen	Kenya	Solomon Islands
Guyana	**Morocco and Tunisia**	Lesotho	Tonga
Paraguay	Morocco	Liberia	Vanuatu
Suriname	Tunisia	Madagascar	
Uruguay		Malawi	
		Mali	
		Mauritania	
		Mauritius	
		Mozambique	
		Namibia	
		Niger	
		Rwanda	
		Senegal	
		Sierra Leone	
		Somalia	
		Sudan	
		Swaziland	

		Tanzania	
		Togo	
		Uganda	
		Zambia	
		Zimbabwe	

Coal production

59 individual countries (4 of which with infra-national detail) + 12 regions

(*): 16 exporters (4 of which with infra-national detail)

Table 19. List of 59 individual coal producing countries represented in POLES-JRC

Non-EU individual countries	EU-28 Member States
Argentina	Austria
Australia (x 2 regions) (*)	Belgium
Brazil	Bulgaria
Canada (*)	Croatia
Chile	Cyprus
China (x 4 regions) (*)	Czechia
Colombia (*)	Denmark
Egypt	Estonia
Iceland	Finland
India (x 4 regions) (*)	France
Indonesia (*)	Germany
Iran	Greece
Japan	Hungary
Kazakhstan (*)	Ireland
Malaysia	Italy
Mexico	Latvia
Mongolia (*)	Lithuania
Mozambique (*)	Luxembourg
New Zealand	Malta
Norway	Netherlands
Russia (*)	Poland (*)
Saudi Arabia	Portugal
South Africa (*)	Romania
South Korea	Slovakia
Switzerland	Slovenia
Thailand	Spain
Turkey	Sweden
Ukraine (*)	United Kingdom
United States (x 4 regions) (*)	
Venezuela (*)	
Vietnam (*)	

Table 20. Country mapping for the 12 coal producing regions in POLES-JRC

Rest Central America	Rest Balkans	Rest Sub-Saharan Africa	Rest South Asia
Bahamas	Albania	Angola	Afghanistan
Barbados	Bosnia and Herzegovina	Benin	Bangladesh
Belize	Former Yugoslav Republic of Macedonia	Botswana	Bhutan
Bermuda	Kosovo	Burkina Faso	Maldives
Costa Rica	Moldova	Burundi	Nepal
Cuba	Montenegro	Cameroon	Pakistan
Dominica	Serbia	Cape Verde	Seychelles
Dominican Republic	**Rest CIS**	Central African Republic	Sri Lanka
El Salvador	Armenia	Chad	**Rest South East Asia**
Grenada	Azerbaijan	Comoros	Brunei
Guatemala	Belarus	Congo	Cambodia
Haiti	Georgia	Democratic Republic of the Congo	Laos
Honduras	Kyrgyzstan	Côte d'Ivoire	Myanmar/Burma
Jamaica	Tajikistan	Djibouti	North Korea
Nicaragua	Turkmenistan	Equatorial Guinea	Philippines
NL Antilles and Aruba	Uzbekistan	Eritrea	Singapore
Panama	**Mediter. Middle East**	Ethiopia	Taiwan
São Tomé and Príncipe	Israel	Gabon	**Rest Pacific**
St Lucia	Jordan	Gambia	Fiji
St Vincent and Grenadines	Lebanon	Ghana	Kiribati
Trinidad and Tobago	Syria	Guinea	Papua New Guinea
Rest South America	**Rest of Persian Gulf**	Guinea-Bissau	Samoa (Western)
Bolivia	Bahrain	Kenya	Solomon Islands
Ecuador	Iraq	Lesotho	Tonga
Guyana	Kuwait	Liberia	Vanuatu
Paraguay	Oman	Madagascar	
Peru	Qatar	Malawi	
Suriname	United Arab Emirates	Mali	
Uruguay	Yemen	Mauritania	
	Morocco and Tunisia	Mauritius	
	Morocco	Namibia	
	Tunisia	Niger	
	Algeria and Libya	Nigeria	
	Algeria	Rwanda	
	Libya	Senegal	
		Sierra Leone	
		Somalia	

		Sudan	
		Swaziland	
		Tanzania	
		Togo	
		Uganda	
		Zambia	
		Zimbabwe	

Annex 3: Equation details of residential and services end-uses

Water heating

$$Residential\ water\ heating\ useful\ energy_{per\ capita} = 0.105 * exp\left(-2.27 * exp(-0.000318 * HDD * (GDP/capita)^{0.23})\right) \quad (in\ toe/cap)$$

$$Service\ water\ heating\ useful\ energy_{percapita} = 0.0291 * \exp\left(-2.22 * \exp\left(-0.0943 * \frac{ValueAdded}{capita}\right)\right) \quad (in\ toe/cap)$$

Cooking

$$Residential\ cooking\ useful\ energy_{per\ capita} = 0.023 \quad (in\ toe/cap)$$

$$Service\ cooking\ useful\ energy_{percapita} = 0.0164 * \exp\left(-4.19 * \exp\left(-0.294 * \frac{ValueAdded}{capita}\right)\right) \quad (in\ toe/cap)$$

Space cooling

$$Maximum\ penetration_{AC} = max\left(2\%, 100\% * \left(1 - e^{-0.0025*(CDD-100)}\right)\right)$$

$$Saturation_{AC,Time} = \frac{Equippedhouseholds}{Maximum\ penetration_{AC}} = Saturation_{AC,Time-1} + 18.9\% * \left(Saturation_{AC,Time-1} - Saturation^2_{AC,Time-1}\right)$$

$$Budgetary\ coefficient\ of\ space\ cooling\ useful\ energy\ of\ equipped\ households = \frac{Space\ cooling\ electricity\ consumption}{Equipped\ dwelling * efficiency} * \frac{electricity\ price}{GDP}$$
$$= 0.00173 + 0.0000356 * CDD^{0.65}$$

$$Service\ space\ cooling\ useful\ energy_{per\ capita} = CDD * 0.00014 * \left(1 - \exp\left(-0.0611 * \exp\left(-0.823 * \frac{\frac{ValueAdded}{capita}}{Electricity\ price^{0.3}}\right)\right)\right) \quad (in\ toe/cap)$$

Appliances

$$Residential\ appliances\ electricity\ consumption_{per\ capita} = 0.009 * \left(\frac{GDP}{capita}\right)^{0.59} \quad (in\ toe/cap)$$

$$Services\ appliances\ electricity\ consumption_{per\ capita} = 0.2 * \left(1 - \exp\left(-0.0564 * \exp\left(-0.0956 * \frac{ValueAdded}{capita}\right)\right)\right) \quad (in\ toe/cap)$$

$$Residential\ appliances\ trend\ with\ respect\ to\ law = 0\ if\ \frac{GDP}{capita} > \frac{50k\$}{cap}, \quad else\ \frac{0.0002471 * \frac{GDP}{capita}^{3} - 0.022165 * \frac{GDP}{capita}^{2} + 0.5056 * \frac{GDP}{capita} - 0.8397}{100}$$

$$Service\ appliances\ trend\ with\ respect\ to\ law = \max\left(-0.001, 0.05195 - 0.001631 * \frac{ValueAdded}{capita}\right)$$

Lighting

$$Residential\ lighting\ electricity\ consumption_{per\ capita} = \max\left(0, 0.00632 + 0.00381 * ln\left(\frac{GDP}{capita}\right) - \frac{0.0000382}{0.00536 + e^{0.605*\frac{GDP}{cap}-21.7}}\right) \quad (in\ \ toe/cap)$$

$$Services\ lighting\ electricity\ consumption_{per\ capita} = 0.103 * \exp\left(-3.03 * \exp\left(-0.0702 * \frac{ValueAdded}{capita}\right)\right) \quad (in\ \ toe/cap)$$

$$Lighting\ trend\ with\ respect\ to\ law = -3\%$$

Annex 4: Sources for hourly electricity load data

Table 21. Sources for hourly electricity load data for countries and regions used.

Country / Region	Regional grid zones	Period	Comment	Source	Link
Argentina	1	2014	Assembled from typical daily profiles (weekday, Saturday, Sunday) per month of total grid.	CAMESA (Compañía Administradora del Mercado Mayorista Eléctrico), Argentina	http://portalweb.cammesa.com/memnet1/Pages/descargas.aspx
Australia	6	1999-2015		Australian Energy Market Operator (AEMO), Australia	http://www.aemo.com.au
Austria	1	2006-2014		ENTSOE	https://transparency.entsoe.eu/
Belgium	1	2006-2014		ENTSOE	https://transparency.entsoe.eu/
Brazil	1	2010-2017	Actually 4 zones, but downloaded as aggregate for total zone.	Operador Nacional do Sistema Eléctrico, Brazil	http://www.ons.org.br/Paginas/resultados-da-operacao/historico-da-operacao/curva_carga_horaria.aspx
Bulgaria	1	2006-2014		ENTSOE	https://transparency.entsoe.eu/
Canada	4	2011-2017		4 zones of Canada: - British Columbia Hydro and Power Authority - Alberta Electric System Operator (AESO) (6 subzones) - Independent Electricity System Operator (IESO) - New Brunswick Power Corporation	https://www.bchydro.com/energy-in-bc/operations/transmission/transmission-system/balancing-authority-load-data/historical-transmission-data.html; https://www.aeso.ca/market/market-and-system-reporting/data-requests/hourly-load-by-area-and-region-2011-to-2017/; http://www.ieso.ca/Pages/Power-Data/default.aspx;

					http://tso.nbpower.com/Public/en/system_information_archive.aspx
Chile	SIC	2004-2015	SIC (Sistema Interconectado Central) covering > 70% of electricity production	Coordinador Eléctrico Nacional, Chile	https://sic.coordinador.cl/informes-y-documentos/operacion-real/
China			Japan is used as proxy for this region.		
Croatia	1	2006-2014		ENTSOE	https://transparency.entsoe.eu/
Cyprus	1	2013-2014		ENTSOE	https://transparency.entsoe.eu/
Czechia	1	2006-2014		ENTSOE	https://transparency.entsoe.eu/
Denmark	1	2010-2014		ENTSOE	https://transparency.entsoe.eu/
Egypt	1	2010		Personal communication	
Estonia	1	2009-2014		ENTSOE	https://transparency.entsoe.eu/
Finland	1	2010-2014		ENTSOE	https://transparency.entsoe.eu/
France	1	2006-2014		ENTSOE	https://transparency.entsoe.eu/
Germany	1	2006-2014	All German zones aggregated by ENTSOE.	ENTSOE	https://transparency.entsoe.eu/
Greece	1	2006-2014		ENTSOE	https://transparency.entsoe.eu/
Hungary	1	2006-2014		ENTSOE	https://transparency.entsoe.eu/
Iceland		2010-2014		ENTSOE	https://transparency.entsoe.eu/
India	NRLDC	2011-2016	Grid zones of WRLDC, ERLDC, SRLDC also available, but not used.	Northern Regional Load Dispatch Centre (NRLDC), India	http://www.nrldc.org

Indonesia	Java & Bali	2008-2016		Bidang Operasi System, Indonesia	http://isolator.pln-jawa-bali.co.id/app4
Iran	1	2012-2016		Iran Grid Management Company, Iran	https://www.igmc.ir/
Ireland	1	2008-2014		ENTSOE	https://transparency.entsoe.eu/
Italia	1	2006-2014		ENTSOE	https://transparency.entsoe.eu/
Japan	TEPCO	2008-2015		TEPCO, Japan	http://www.tepco.co.jp/en/forecast/html/index-e.html
Latvia	1			ENTSOE	https://transparency.entsoe.eu/
Lithuania	1	2010-2014		ENTSOE	https://transparency.entsoe.eu/
Luxembourg	1	2006-2014		ENTSOE	https://transparency.entsoe.eu/
Malaysia	1	2013-2016		Tenaga Nasional Berhad, Malaysia	https://www.tnb.com.my/suppliers-investors-media-relations/daily-system-generation-summary
Malta			Cyprus is used as proxy for this region.		
Mexico	7	2015		Personal communication with *Centro Nacional de Control de Energía, Mexico*	https://www.gob.mx/cenace
Netherlands	1	2006-2014		ENTSOE	https://transparency.entsoe.eu/
New Zealand	1	1998-2014	Refers to generation	Electricity Market Information, New Zealand	https://www.emi.ea.govt.nz/Wholesale/Datasets/Generation/Generation_MD/
Norway	1	2010-2014		ENTSOE	https://transparency.entsoe.eu/

Poland	1	2006-2014		ENTSOE	https://transparency.entsoe.eu/
Portugal	1	2006-2014		ENTSOE	https://transparency.entsoe.eu/
Romania	1	2006-2014		ENTSOE	https://transparency.entsoe.eu/
Russia	2	2013-2015		Atsenergo, Russia	http://www.atsenergo.ru
Saudi Arabia	4	2013		Personal communication	
Slovakia	1	2006-2014		ENTSOE	https://transparency.entsoe.eu/
Slovenia	1	2006-2014		ENTSOE	https://transparency.entsoe.eu/
South Africa	1	2010		IRENA project: "Southern African Power Pool: Planning and Prospects for Renewable Energy"	
South Korea	1	2016		Korea Power Exchange (KPX) – Electric Power System Information System (EPSIS), Korea	http://epems.kpx.or.kr/downpdf.kpx
Spain	1	2006-2014		ENTSOE	https://transparency.entsoe.eu/
Sweden	1	2010-2014		ENTSOE	https://transparency.entsoe.eu/
Switzerland	1	2006-2014		ENTSOE	https://transparency.entsoe.eu/
Thailand			Philippines is used as proxy.		
Turkey	1	2013-2016		Turkish Electricity Transmission Corporation, Turkey	https://www.teias.gov.tr/

Ukraine	1	2006-2014	Western grid of Ukraine used as proxy.	ENTSOE	https://transparency.entsoe.eu/
United Kingdom	1	2010-2014		ENTSOE	https://transparency.entsoe.eu/
USA	173	2006-2016	Form 714 of FERC.	Federal Energy Regulatory Commission (FERC), USA	https://www.ferc.gov/docs-filing/forms/form-714/overview.asp
Vietnam			Philippines is used as proxy for this region.		
Algeria and Libya	2	2010	Sum of Algeria & Libya.	Personal communication	
Morocco and Tunisia	2	2010	Sum of Morocco & Tunisia.	Personal communication	
Rest Balkans	3	2010-2014	Sum of Bosnia and Herzegovina, FYR Macedonia and Serbia.	ENTSOE	https://transparency.entsoe.eu/
Rest Central America	1	2013-2015	Costa Rica as part of the region is used as proxy; data refers to generation.	Sistema Eléctrico Nacional, Costa Rica	https://appcenter.grupoice.com/CenceWeb/CencePredespachoTecnicoNacional.jsf
Rest CIS			Russia is used as proxy for this region.		
Rest Mediterranean & Middle East			Egypt is used as proxy for this region.		
Rest Pacific			Philippines are used as proxy for this region.		
Rest of Persian Gulf			Saudi Arabia is used as proxy for this region.		
Rest South America	1	2014	Colombia as part of the region is used as proxy.	Sistema Eléctrico Nacional, Columbia	https://apps.grupoice.com/CenceWeb/CencePredespachoTecnicoNacional.jsf

Rest South Asia	1	2011	Pakistan as part of the region is used as proxy.	National Transmission and Dispatch Company (NTDC), Pakistan	http://www.ntdc.com.pk/
Rest South East Asia	1	2016-2017	Philippines is used as proxy for this region.	Wholesale Electricity Spot Market (WESM), Philippines	http://www.wesm.ph/inner.php/downloads/market_prices_&_schedules
Rest Sub-Saharan Africa	1	2010	Ivory Coast as part of the region is used as proxy.	IRENA project: “Southern African Power Pool: Planning and Prospects for Renewable Energy”	

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