

WORLD
ENERGY
MODEL
DOCUMENTATION

2018 VERSION

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1 Background

Since 1993, the International Energy Agency (IEA) has provided medium- to long-term energy projections using the World Energy Model (WEM). The model is a large-scale simulation model designed to replicate how energy markets function and is the principal tool used to generate detailed sector-by-sector and region-by-region projections for the *World Energy Outlook (WEO)* scenarios. Updated every year and developed over many years, the model consists of three main modules: final energy consumption (covering residential, services, agriculture, industry, transport and non-energy use); energy transformation including power generation and heat, refinery and other transformation; and energy supply. Outputs from the model include energy flows by fuel, investment needs and costs, CO₂ emissions and end-user pricing.

The WEM is a very data-intensive model covering the whole global energy system. Much of the data on energy supply, transformation and demand, as well as energy prices is obtained from the IEA's own databases of energy and economic statistics (<http://www.iea.org/statistics>). Additional data from a wide range of external sources is also used. These sources are indicated in the relevant sections of this document.

The WEM is constantly reviewed and updated to ensure its completeness and relevancy. The development of the WEM benefits from expert review within the IEA and beyond and the IEA works closely with colleagues in the modelling community, for example, by participating in and hosting the annual International Energy Workshop (<http://internationalenergyworkshop.org>).

The current version of WEM covers energy developments up to 2040 in 25 regions. Depending on the specific module of the WEM, individual countries are also modelled: 12 in demand; 101 in oil and gas supply; and 19 in coal supply (see Annex 1). The WEM is designed to analyse:

- **Global and regional energy prospects:** These include trends in demand, supply availability and constraints, international trade and energy balances by sector and by fuel to 2040.
- **Environmental impact of energy use:** CO₂ emissions from fuel combustion are derived from the projections of energy consumption. Greenhouse gases and local pollutants are also estimated linking WEM with other models.
- **Effects of policy actions and technological changes:** Alternative scenarios analyse the impact of policy actions and technological developments on energy demand, supply, trade, investments and emissions.
- **Investment in the energy sector:** The model evaluates investment requirements in the fuel supply chain needed to satisfy projected energy demand to 2040. It also evaluates demand-side investment requirements, including energy efficiency, electric vehicles and industrial carbon capture and storage.
- **Modern energy access prospects:** These include trends in access to electricity and clean cooking facilities to 2040. It also evaluates additional energy demand, investments and CO₂ emissions due to increased energy access.

1.1 WEO scenarios

The *World Energy Outlook* makes use of a scenario approach to examine future energy trends relying on the WEM. For the *World Energy Outlook 2018 (WEO-2018)*, detailed projections for three scenarios were modelled and presented: the New Policies Scenario, the Current Policies Scenario and the Sustainable Development Scenario. The scenarios differ with respect to what is assumed about future government policies related to the energy sector. There is much uncertainty about what governments will actually do over the coming quarter of a century, but it is highly likely that they will continue to intervene in energy markets. Indeed, many countries have announced formal objectives; but it is very hard to predict with any degree of certainty what policies and measures will actually be introduced or how successful they will be. The commitments and targets will undoubtedly change in the course of the years to come.

The **New Policies Scenario** – our central scenario – takes into account the policies and implementing measures affecting energy markets that had been adopted as of mid-2018, together with relevant policy proposals, even though specific measures needed to put them into effect have yet to be fully developed (Table 1). The New Policies Scenario assumes only cautious implementation of current commitments and plans. This is done in view of the many institutional, political and economic obstacles which exist, as well as, in some cases, a lack of detail in announced intentions and about how they will be implemented. For example, the GHG- and energy-related components of the Nationally Determined Contributions (NDCs) pledged under the Paris Agreement are incorporated. Where the energy policy landscape has continued to evolve since the NDCs were announced the NPS has been updated, becoming more ambitious in terms of GHG emissions reductions in some countries and less ambitious in others. But we take a generally cautious view in the New Policies Scenario of the extent and timing of which policy proposals will be implemented.

To illustrate the outcome of our current course, if unchanged, the **Current Policies Scenario** embodies the effects of only those government policies and measures that had been enacted or adopted by mid-2018. Without implying that total inaction is probable, it does not take into account any possible, potential or even likely future policy actions. It does however embody technological improvements. The scenario is designed to offer a baseline picture of how global energy markets would evolve without any new policy intervention.

Table 1 Definitions and objectives of the *WEO-2018* scenarios

	Current Policies Scenario	New Policies Scenario	Sustainable Development Scenario	Future is Electric Scenario
Definitions	Government policies that had been enacted or adopted by mid-2018 continue unchanged.	Existing policies are maintained and recently announced commitments and plans, including those yet to be formally adopted, are implemented in a cautious manner.	An integrated scenario specifying a pathway aiming at: ensuring universal access to affordable, reliable, sustainable and modern energy services by 2030 (SDG 7); substantially reducing air pollution (SDG 3.9); and taking effective action to combat climate change (SDG 13).	Assume that electric technologies will be widely taken up in this sector as soon as they become cost-competitive, because policy makers remove non-economic barriers.
Objectives	To provide a baseline that shows how energy markets would evolve if underlying trends in energy demand and supply are not changed.	To provide a benchmark to assess the potential achievements (and limitations) of recent developments in energy and climate policy.	To demonstrate a plausible path to concurrently achieve universal energy access, set a path towards meeting the objectives of the Paris Agreement on climate change and significantly reduce air pollution	To explore what would happen if specific policies and technology cost reductions were to lead to a faster pace of electricity demand growth.

The **Sustainable Development Scenario**, introduced for the first time in the *WEO-2017*, aims to provide an energy sector pathway that combines the fundamentals of sectoral energy policy with three closely associated but distinct policy objectives, all of which are crucial pillars of the UN Sustainable Development Goals (SDGs). First, it describes a pathway to the achievement of universal access to modern energy services by 2030, including not only access to electricity but also clean cooking. Second, it paints a picture to 2040 that is consistent with the direction needed to achieve the objectives of the Paris Agreement, including a peak in emissions being reached as soon as possible, followed by a substantial decline. Third, it posits a large

reduction in other energy-related pollutants, consistent with a dramatic improvement in global air quality and a consequent reduction in premature deaths from household air pollution. The objective is to lay out an integrated least-cost strategy for the achievement of these important policy objectives, alongside energy security, in order to show how the respective objectives can be reconciled, dealing with potentially conflicting priorities, so as to realise mutually-supportive benefits (see Box 1).

The ***Future is Electric Scenario***, is a scenario developed specifically for the *WEO-2018* special focus on electrification. It starts from the conditions of the New Policies Scenario and explores key areas of uncertainty for future electricity demand. One main type of uncertainty relates to increased electricity demand for new or expanded energy needs. In the Future is Electric Scenario, we assume that a range of electric technologies are widely taken up as soon as they become cost-competitive by removing any constraints related to infrastructure, supply chains or consumer preference for existing technologies. We also accelerate the pace at which universal access to electricity is achieved. As a result, the share of electricity in final consumption rises to 31% by 2040. This is mainly thanks to a much more rapid adoption of heat pumps in buildings and for the provision of low-temperature heat in industry, and a swift transformation in the transport sector that puts almost a billion electric cars on the road by 2040 (IEA, 2018b).

Other scenarios and cases referred to in this report are:

- **Faster Transition Scenario** – This scenario, developed in 2017, plots an emissions pathway to “net zero” energy sector CO₂ emissions in 2060 resulting in lower emissions than the Sustainable Development Scenario in 2040.¹
- **Low Oil Price Case** – This case looks at the conditions that would allow the oil price to remain “lower for longer”; it updates the work done in the *WEO-2015* on a Low Oil Price Scenario.
- **Energy for All Case** – Developed specifically for the *WEO-2017*, this case examines the achievement of modern energy for all against the backdrop of the New Policies Scenario. It provides a point of comparison
- **450 Scenario** – This scenario was not modelled for the *WEO-2017*, but in recent Outlooks it has been the main decarbonisation scenario. Previous results are used on occasion for purposes of comparison.
- **Clean Air Scenario** – Introduced in a Special Report in the *WEO-2016* series, this set out a cost-effective strategy, based on existing technologies and proven policies, to cut 2040 pollutant emissions by more than half compared with the New Policies Scenario.
- **Bridge Scenario** – Featured in another Special Report, this time in the *WEO-2015* series, this put forward a bridging strategy, based on five specific energy sector measures, to achieve an early peak in energy-related CO₂ emissions.

The WEM scenarios allow us to evaluate the impact of specific policies and measures on energy demand, production, trade, investment needs, supply costs and emissions. A policies and measures database, detailing policies addressing renewable energy, energy efficiency, and climate change, supports the analysis. This database is available at: <http://www.iea.org/policiesandmeasures/>.

¹ The Faster Transition Scenario draws on a scenario prepared in support of the 2017 G20 presidency, featured in IEA (2017a)

Box 1: An integrated approach to energy and sustainable development

The Sustainable Development Scenario, introduced for the first time in WEO 2017, integrates three key objectives of the UN 2030 Agenda for Sustainable Development: universal access to modern energy services by 2030 (embodied in SDG 7), action to tackle climate change (SDG 13) and reducing health impacts of air pollution (SDG 3.9). In a first step, we use the WEM to assess the energy sector implications and requirements to reach universal access to modern energy by 2030. To analyse electricity access, we combine cost-optimisation with new geospatial analysis that takes into account current and planned transmission lines, population density, resource availability and fuel costs. We consider all technologies and fuels in the analysis, including fossil fuels, as achieving universal access to modern energy by 2030 will not cause a net increase in global GHG emissions: a small CO₂ increase is more than offset by declines in other GHG emissions, notably methane from reduced biomass combustion (IEA, 2017b).

In a second step, we consider goals related both to addressing climate change and outdoor air pollution, the point of departure being WEO's established 450 Scenario. The Sustainable Development Scenario takes both environmental goals as equally important. This implies that there are many conceptual similarities between the 450 Scenario used in previous WEO editions and the new Sustainable Development Scenario, partly because both scenarios aim at mitigating climate change. But also because many of the available technology solutions for addressing climate change are similar to for reducing air pollution.

However, the target to achieve universal energy access by 2030 and the significance of the impact of air pollution on human health already today mean that technology choices in the Sustainable Development Scenario differ from the 450 Scenario that was solely driven by climate considerations. The emphasis of the Sustainable Development Scenario is on technologies with short project lead times in the power sector in particular, such as renewables, while the longer-term nature of climate change allows for other technology choices. Modern uses of biomass as a decarbonisation option is also somewhat less relevant in a Sustainable Development Scenario than in a dedicated climate scenario. The reason is that biomass is a combustible fuel, which means that its use requires post-combustion control to limit air pollutant emissions in the Sustainable Development Scenario and this may, in some instances, render its use more costly than that of available alternatives.

1.2 New features in the World Energy Outlook 2018

The following changes were made to WEM for the purposes of the *WEO-2018*:

Final energy consumption

Industry module:

- For *WEO-2018*, the updated WEM Industry module includes the possibility to use of hydrogen as direct fuel or as feedstock for ammonia production. Intensities and efficiencies of related processes are aligned with assumptions used for the Energy Technology Perspectives report (IEA, 2017c). For ammonia the used hydrogen does not appear in the balance, as it is only an intermediate product. Only the electricity consumed in the electrolysis, synthesis and in the air-separation processes appear in the balance.
- Chemical sector models have been updated as a result of work feeding into the Future of Petrochemicals report. Data sources for historic production of chemical products have been updated, along with the feedstock intensities, in both cases with the goal of better aligning with the Energy Technology Perspectives report (IEA, 2017c). The sectoral boundaries for propylene and aromatics have been updated, moving refinery production out of the chemicals sector energy/feedstock demand and including better representation of energy demand for steam crackers.
- Key inputs to cement sector modelling (energy intensities, clinker ratios) were revised to align with findings from the recent technology roadmap on cement (IEA, 2018c).

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Buildings module:

- The updated WEM Buildings module for *WEO-2018* includes the possibility for hydrogen to be used directly to meet end-use energy demand in both residential and services buildings.
- Efficiency and investment cost input data for building equipment and appliances has been updated based on wide ranging market research and academic literature. The modelling of investment cost projections has been enhanced, notably for residential and commercial appliances. This update is based on observed and expected cost declines, linked to deployment levels, notably for the most efficient classes of appliances.
- Inputs to electricity demand projections to meet space cooling service needs were updated to link to the ETP Buildings Model (used to produce the *Future of Cooling* report in 2018). As a result, *WEO-2018* benefits from increased precision in modelling changes to population weighted cooling degree days and relative humidity over time, due to changes in population and expected evolution of climatic conditions.

Transport module:

- An update of battery capacities per electric vehicle type was done using the IEA in-house Mobility Model (MoMo) database and most recent literature.
- An EV battery material demand sub-module was developed. It is based on a thorough literature review, alongside IEA's workshop outcomes and experts' consultation for identifying the material intensity factors, the dominant battery chemistries and the future battery technologies.
- For the purpose of the H2020 Energy Union project, the transport module was expanded and coupled with a bottom-up tool for projecting the future passenger car fleet and the new registrations for all EU28 countries, Switzerland and Norway. EVs deployment across these countries is driven by policy frameworks and national targets (i.e. CO₂ standards and plans for phasing-out conventional cars).
- A LPG sub-module was added for assessing the competitiveness of LPG-powered vehicles. An analytical tool has been developed, incorporating capital costs (i.e. conversion kit costs), fuel costs,

tax incentives, infrastructure developments, market maturity and vehicle characteristics (i.e. efficiency performance). The current policy framework and announced plans for supporting alternative fuels in combination with market dynamics feed our analysis on LPG vehicles penetration.

- *WEO-2018* saw the development of a sub-module on recharging infrastructure investments. An analytical tool for estimating the future investments on EV recharging infrastructure has been developed. Historical data for the current deployment of recharging points per power classification were drawn from MoMo database. For the estimation of the trend of recharging point ratio per electric vehicle, geographical characteristics, urbanisation ratios, consumers preference and policy targets have been captured. The future cost of recharging points follows a declining trend and is benefitted by the economies of scale and learning by doing effects; a range of cost curves has been constructed for the main WEM regions.
- Improvements of EV projections were made beyond passenger cars, while taking into account consistency of the approach across regions and with GEVO-2018 (IEA, 2018a). Oil displacement calculation from alternative fuel vehicles, CO₂ performance and indirect emissions of road transport were implemented into the WEM.

Energy access

- For *WEO-2018*, the IEA newly incorporated more granular country-level data on cooking by fuel type, based on the World Health Organization's database (WHO, 2018) and developed with cross-checks against IEA energy balances.

Demand-side response:

- For *WEO-2018*, hourly modelling of electricity demand by end-use was refined. The principal improvements include: 1) linking monthly heating and cooling demand profiles to population weighted, cooling degree day, relative humidity and heating degree day data, 2) update of hourly demand profiles for residential appliances based on historically observed profiles and academic literature.
- A smart charging optimiser was added within the hourly load model. This optimiser allows WEM to demonstrate the potential reductions in peak demand that can be achieved by optimising the charging profiles of electric vehicles.

Power generation:

- The value-adjusted LCOE (VALCOE) is a new metric for competitiveness for power generation technologies. It was developed for the *WEO-2018*, building on the capabilities of the WEM hourly power supply model. It is intended to complement the LCOE, which only captures relevant information on costs and does not reflect the differing value propositions of technologies. VALCOE enables comparisons that take account of both cost and value between variable renewables and dispatchable thermal technologies.
- The WEM this year incorporates a new and fuller modelling of battery storage. In particular, two types of battery storage deployment have been included: utility-scale paired with variable renewables (utility-scale solar PV, wind onshore and offshore) and utility-scale stand-alone systems. Battery storage installations are determined based on the value-adjusted LCOE, taking into account not only the cost of the technology choice but also the value derived from energy, capacity and ancillary service markets.
- The WEM was expanded and coupled with other tools to provide a detailed picture of the operations of the European Union power system for the analysis of the costs and benefits of the Energy Union. On the power generation side, while capacity expansion was derived from the WEM, dispatch was simulated through WEM hourly model and was further complemented by country level projections

using Artelys Crystal Super Grid model,² simulating the operations of the European Union electricity market in 2030 at the hourly and country level, including an explicit representation of trade flows. Both tools operate on the basis of the short-run marginal operating costs of each plant and were subjected to generator technical characteristics. VRE availability constraints were reflected through hourly production profiles for wind power, solar PV and hydropower for each country.

Energy supply:

- For this year's edition of the WEO, we developed a European gas infrastructure model, allowing us to examine trade flows and potential bottlenecks on a disaggregated country-by-country basis. The modelled countries include the EU-28, plus Switzerland and countries of southeast Europe that are contracting parties to the Energy Community Treaty.

Emissions:

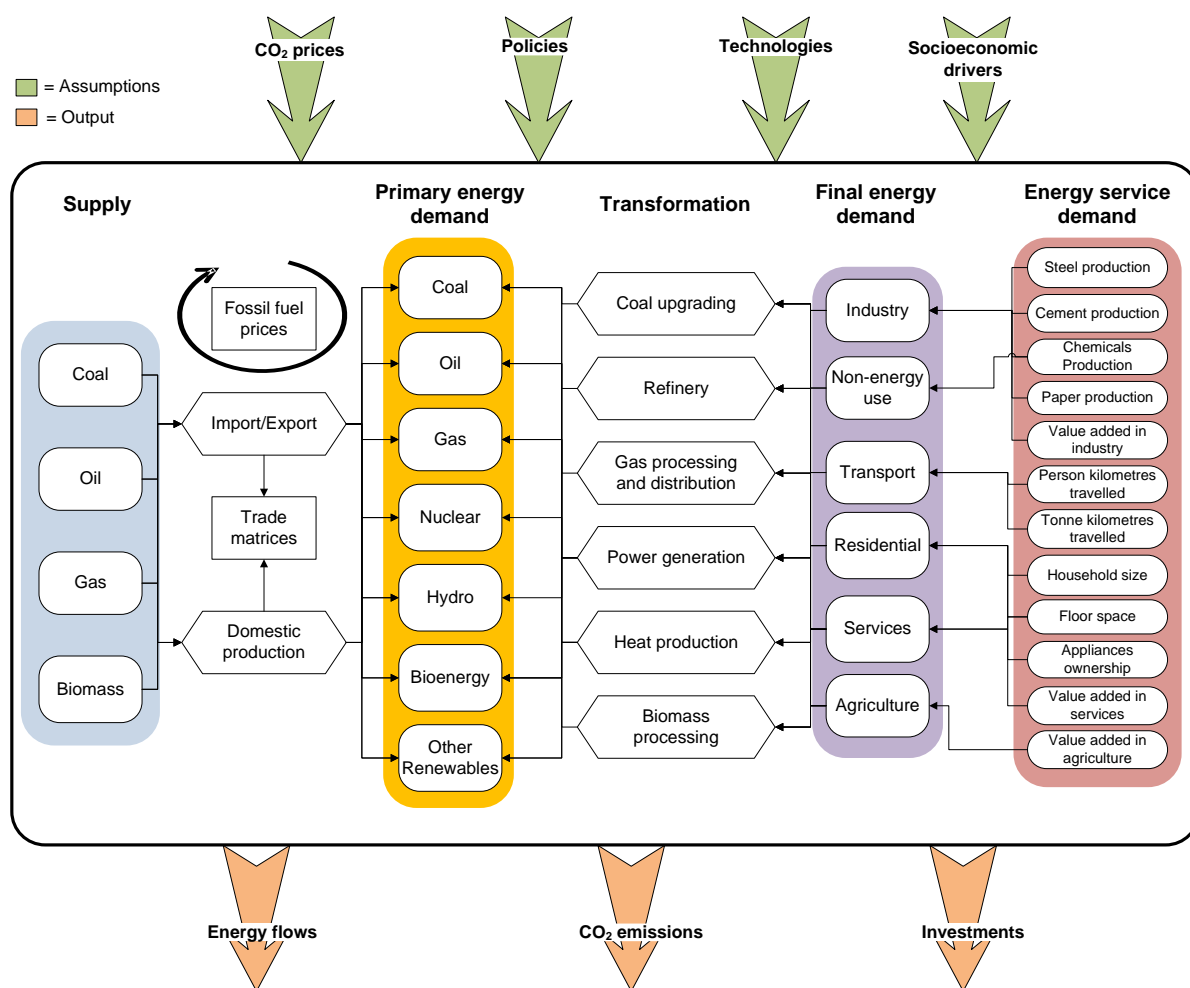
- The methodology to account for CO₂ emissions in Gas-to-Liquid and Coal-to-Liquid processes was revisited.

² www.artelys.com/en/applications/artelys-supergrid.

1.3 World Energy Model structure

The WEM is a simulation model covering energy supply, energy transformation and energy demand. The majority of the end-use sectors use stock models to characterise the energy infrastructure. In addition, energy-related CO₂ emissions and investments related to energy developments are specified. Though the general model is built up as a simulation model, specific costs play an important role in determining the share of technologies in satisfying an energy service demand. In different parts of the model, Logit and Weibull functions are used to determine the share of technologies based upon their specific costs. This includes investment costs, operating and maintenance costs, fuel costs and in some cases costs for emitting CO₂.

Figure 1: World Energy Model Overview

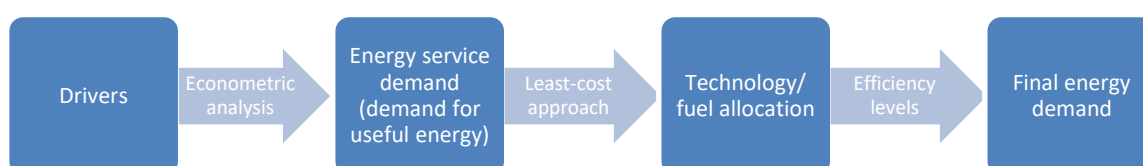


The main exogenous assumptions concern economic growth, demographics and technological developments. Electricity consumption and electricity prices dynamically link the final energy demand and transformation sector. Consumption of the main oil products is modelled individually in each end-use sector and the refinery model links the demand for individual products to the different types of oil. Demand for primary energy serves as input for the supply modules. Complete energy balances are compiled at a regional level and the CO₂ emissions of each region are then calculated using derived CO₂ factors. The time horizon of the model goes out to 2040 with annual steps in between. The model is each year recalibrated to the latest available data point (for *WEO-2018*, this is typically 2016 although 2017 data is included where available).

2 Technical aspects and key assumptions

Demand side drivers, such as steel production in industry or household size in dwellings, are estimated econometrically based on historical data and on socioeconomic drivers. All end-use sector modules base their projections on the existing stock of energy infrastructure. This includes the number of vehicles in transport, production capacity in industry, and floor space area in buildings. The various energy service demands are specifically modelled, in the residential sector *e.g.* into space heating, water heating, cooking, lighting, appliances, space cooling. To take into account expected changes in structure, policy or technology, a wide range of technologies are integrated in the model that can satisfy each specific energy service. Respecting the efficiency level of all end-use technologies gives the final energy demand for each sector and sub-sector (Figure 2). Simulations are carried out on an annual basis. The WEM is implemented in the simulation software Vensim (www.vensim.com), but makes use of a wider range of software tools.

Figure 2: General structure of demand modules



The same macroeconomic and demographic assumptions are used in all the scenarios, unless otherwise specified. The projections are based on the average retail prices of each fuel used in final uses, power generation and other transformation sectors. These end-use prices are derived from projected international prices of fossil fuels and subsidy/tax levels.

2.1 Population assumptions

Rates of population growth for each WEM region are based on the medium-fertility variant projections contained in the United Nations Population Division report (UNPD, 2015). In WEO-2018, world population is projected to grow by 0.9% per year on average, from 7.5 billion in 2017 to 9.2 billion in 2040. Population growth slows over the projection period, in line with past trends: from 1.2% per year in 2000-2017 to 1.0% in 2017-2025 (Table 2).

Estimates of the rural/urban split for each WEM region have been taken from UNDP (2014). This database provides the percentage of population residing in urban areas by country in 5-yearly intervals to 2050. By combining this data³ with the UN population projections an estimate of the rural/urban split may be calculated. In 2017, about 55% of the world population is estimated to be living in urban areas. This is expected to rise to 64% by 2040.

³Rural/Urban percentage split is linearly interpolated between the 5-yearly intervals.

Table 2: Population assumptions by region

	Compound average annual growth rate			Population (million)		Urbanisation rate	
	2000-17	2017-25	2017-40	2017	2040	2017	2040
North America	1.0%	0.8%	0.7%	487	571	81%	87%
United States	0.9%	0.7%	0.6%	327	376	82%	87%
Central and South America	1.2%	0.8%	0.6%	516	599	81%	86%
Brazil	1.0%	0.6%	0.4%	209	232	86%	91%
Europe	0.3%	0.1%	0.1%	690	700	75%	81%
European Union	0.3%	0.1%	0.0%	512	513	75%	82%
Africa	2.6%	2.4%	2.3%	1 256	2 100	42%	54%
South Africa	1.4%	1.1%	0.9%	57	69	66%	76%
Middle East	2.3%	1.6%	1.4%	237	323	71%	78%
Eurasia	0.4%	0.4%	0.2%	232	243	65%	70%
Russia	-0.1%	-0.1%	-0.3%	144	136	74%	80%
Asia Pacific	1.1%	0.7%	0.5%	4 098	4 636	47%	60%
China	0.5%	0.3%	0.0%	1 392	1 401	58%	77%
India	1.4%	1.0%	0.8%	1 339	1 605	34%	46%
Japan	-0.0%	-0.3%	-0.4%	126	114	92%	94%
Southeast Asia	1.3%	1.0%	0.7%	646	766	48%	61%
World	1.2%	1.0%	0.9%	7 516	9 172	55%	64%

Source: IEA (2018b).

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2.2 Macroeconomic assumptions

Economic growth assumptions for the short to medium term are based largely on those prepared by the OECD, IMF and World Bank. Over the long term, growth in each WEM region is assumed to converge to an annual long-term rate. This is dependent on demographic and productivity trends, macroeconomic conditions and the pace of technological change.

In *WEO-2018*, world gross domestic product (GDP) is expected to grow on average by 3.4% per year over the projection period (Table 3). That rate is slower than past trends (3.6% in 2000-2017). Annual average growth is assumed to drop from 3.7% over 2017-2025 to 3.3% over 2025-2040. India is expected to grow faster than all other regions, followed by China and Southeast Asia. As observed historically in advanced economies, many regions are expected to shift away from energy-intensive heavy manufacturing towards lighter industries and services, though the pace of this process varies. Industrial production growth over the next decades is going to come mainly from developing economies.

Table 3: Real GDP growth assumptions by region

	Compound average annual growth rate			
	2000-17	2017-25	2025-40	2017-40
North America	1.9%	2.1%	2.1%	2.1%
United States	1.8%	2.0%	2.0%	2.0%
Central and South America	2.7%	2.6%	3.0%	2.9%
Brazil	2.3%	2.3%	3.0%	2.8%
Europe	1.8%	2.1%	1.6%	1.8%
European Union	1.5%	1.8%	1.4%	1.6%
Africa	4.4%	4.1%	4.4%	4.3%
South Africa	2.8%	1.9%	2.8%	2.5%
Middle East	4.1%	3.3%	3.5%	3.4%
Eurasia	4.0%	2.2%	2.5%	2.4%
Russia	3.4%	1.6%	2.1%	1.9%
Asia Pacific	6.0%	5.4%	4.0%	4.5%
China	9.1%	5.8%	3.7%	4.4%
India	7.2%	7.8%	5.7%	6.5%
Japan	0.8%	0.7%	0.7%	0.7%
Southeast Asia	5.2%	5.3%	4.0%	4.5%
World	3.6%	3.7%	3.3%	3.4%

Note: Calculated based on GDP expressed in year-2016 dollars in PPP terms..

Source: IEA (2018b).

2.3 Prices

2.3.1 International fossil fuel prices

International prices for coal, natural gas and oil in the WEM reflect the price levels that would be needed to stimulate sufficient investment in supply to meet projected demand. They are one of the fundamental drivers for determining fossil-fuel demand projections in all sectors and are derived through iterative modelling. The supply modules calculate the output of coal, gas and oil that is stimulated under the given price trajectory taking account of the costs of various supply options and the constraints on production rates. In the case that the price is not sufficient to cover global demand, a price feedback is provided into the previous price level and the energy demand is recalculated. The new demand arising from this iterative process is again fed back into the supply modules until the balance between demand and supply is reached in each year of projections. The resulting fossil fuel price trajectories appear smooth, but in reality prices are likely to be more volatile and cyclic.

Fossil fuel price paths vary across the scenarios. For example, in the Current Policies Scenario, policies adopted to reduce the use of fossil fuels are limited. This leads to higher demand and, consequently, higher prices, although prices are not high enough to trigger widespread substitution of fossil fuels by renewable energy sources. Lower energy demand in the Sustainable Development Scenario means that limitations on the production of various types of resources are less significant and there is less need to produce fossil fuels from resources higher up the supply cost curve. As a result, international fossil fuel prices are lower than in the Current Policies and New Policies scenarios.

Table 4: Fossil-fuel import prices by scenario

Real terms (\$2017)	2000	2010	2017	New Policies				Current Policies		Sustainable Development	
				2025	2030	2035	2040	2025	2040	2025	2040
IEA crude oil (\$/barrel)	39	88	52	88	96	105	112	101	137	74	64
Natural gas (\$/MBtu)											
United States	6.0	4.9	3.0	3.3	3.8	4.3	4.9	3.4	5.3	3.3	3.6
European Union	3.9	8.4	5.8	7.8	8.2	8.6	9.0	7.9	9.4	7.5	7.7
China	3.6	7.5	6.5	9.2	9.4	9.5	9.8	9.3	10.2	8.3	8.5
Japan	6.6	12.3	8.1	9.8	10.0	10.0	10.1	9.9	10.5	9.0	8.8
Steam coal (\$/tonne)											
United States	38	64	60	63	63	64	64	64	69	58	56
European Union	47	103	85	80	83	84	85	84	98	69	66
Japan	45	120	95	85	88	89	90	89	105	74	70
Coastal China	35	130	102	91	93	94	94	95	106	81	79

Notes: MBtu = million British thermal units. The IEA crude oil price is a weighted average import price among IEA member countries. Natural gas prices are weighted averages expressed on a gross calorific-value basis. The US gas price reflects the wholesale price prevailing on the domestic market. The EU and China gas prices reflect a balance of pipeline and liquefied natural gas (LNG) imports, while the Japan gas price is solely LNG imports; the LNG prices used are those at the customs border, prior to regasification. Steam coal prices are weighted averages adjusted to 6 000 kilocalories per kilogramme. The US steam coal price reflects mine-mouth prices (primarily in the Powder River Basin, Illinois Basin, Northern Appalachia and Central Appalachia markets) plus transport and handling cost. Coastal China steam coal price reflects a balance of imports and domestic sales, while the EU and Japanese steam coal price is solely for imports.

Source: IEA (2018b).

2.3.2 CO₂ prices

CO₂ price assumptions are one of the inputs into WEM as the pricing of CO₂ emissions affects demand for energy by altering the relative costs of using different fuels. Several countries have already today introduced emissions trading schemes in order to price carbon, while many others have schemes under development. Other countries have introduced carbon taxes – taxes on fuels according to their related emissions when combusted – or are considering to do so.

The Current Policies Scenario only takes into consideration existing and planned programmes, where the price of CO₂ is assumed to rise under each regional programme over the projection period. Furthermore, all investment decision in the power sector in the United States, Canada and Japan factor in an implicit price for carbon into from 2015. This takes account of the expectation of some form of action that will penalise CO₂ emissions, although we do not assume that explicit trading is introduced. In the Sustainable Development Scenario, it is assumed that CO₂ pricing is established in all OECD countries and that CO₂ prices in these markets start to converge from 2025, reaching \$140/tonne CO₂ in most OECD countries in 2040. In addition, several non-OECD countries are assumed to put in place cap-and-trade schemes to limit CO₂ emissions. All regional markets have access to offsets, which is expected to lead to a convergence of prices (Table 5).

Table 5: CO₂ price in selected regions by scenario (\$2017 per tonne)

Region	Sector	2025	2040
Current Policies Scenario			
Canada	Power, industry, aviation, others*	35	39
Chile	Power	5	5
China	Power	15	31
European Union	Power, industry, aviation	22	38
Korea	Power, industry	22	39
New Policies Scenario			
Canada	Power, industry, aviation, others*	35	39
Chile	Power	8	20
China	Power, industry, aviation	17	36
European Union	Power, industry, aviation	25	43
Korea	Power, industry	25	44
South Africa	Power, industry	11	24
Sustainable Development Scenario			
Advanced economies	Power, industry, aviation**	63	140
Selected emerging economies	Power, industry, aviation**	60	140

*In Canada's benchmark/backstop policies, a carbon price is applied to fuel consumed in additional sectors.

**Coverage of aviation is limited to the same regions as in the New Policies Scenario.

Source: IEA (2018b).

2.3.3 End-user prices

2.3.3.1 Fuel end-use prices

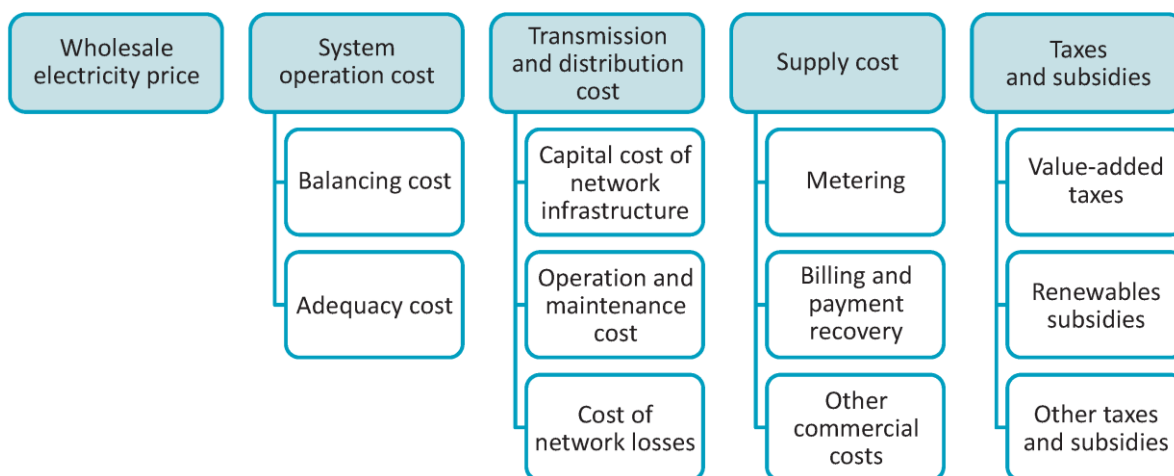
For each sector and WEM region, a representative price (usually a weighted average) is derived taking into account the product mix in final consumption and differences between countries. International price assumptions are then applied to derive average pre-tax prices for coal, oil, and gas over the projection period. Excise taxes, value added tax rates and subsidies are taken into account in calculating average post-tax prices for all fuels. In all cases, the excise taxes and value added tax rates on fuels are assumed to remain unchanged over the projection period. We assume that energy-related consumption subsidies are gradually reduced over the projection period, though at varying rates across the WEM regions and the scenarios. In the Sustainable Development Scenario, the oil price drops in comparison to the New Policies Scenario due to lower demand for oil products. In order to counteract a rebound effect in the transport sector from lower gasoline and diesel prices, a CO₂ tax is introduced in the form of an increase of fuel duty to keep end-user prices at the same level as in the New Policies Scenario. All prices are expressed in US dollars per tonne of oil equivalent and assume no change in exchange rates.

2.3.3.2 Electricity end-use prices

The model calculates electricity end-use prices as a sum of the wholesale electricity price, system operation cost, transmission & distribution costs, supply costs, and taxes and subsidies (Figure 3). Wholesale prices are calculated based on the costs of generation in each region, under the assumption that all plants recover their variable costs and that new additions recover their full costs of generation, including their capital costs. System operation costs are taken from external studies and are increased in the presence of variable renewables in line with the results of these studies. Transmission and distribution tariffs are estimated based on a regulated rate of return on assets, asset depreciation and operating costs. Supply costs are estimated from historic data, and taxes and subsidies are also taken from the most recent historic data, with subsidy

phase-out assumptions incorporated over the Outlook period in line with the relevant assumptions for each scenario.

Figure 3: Components of electricity prices



There is no single definition of wholesale electricity prices, but in the World Energy Model the wholesale price refers to the average price (across time segments) paid to generators for their output. They reflect the region-specific costs of generating electricity for the marginal power plants in each time segment, plus any capital costs that are not recovered. The key factors affecting wholesale prices are therefore:

- The capital cost of electricity generation plants;
- The operation and maintenance costs of electricity generation plants; and
- The variable fuel and, if applicable, CO₂ cost of generation plants' output.

Wholesale electricity price

The derivation of the wholesale price for any region makes two fundamental assumptions:

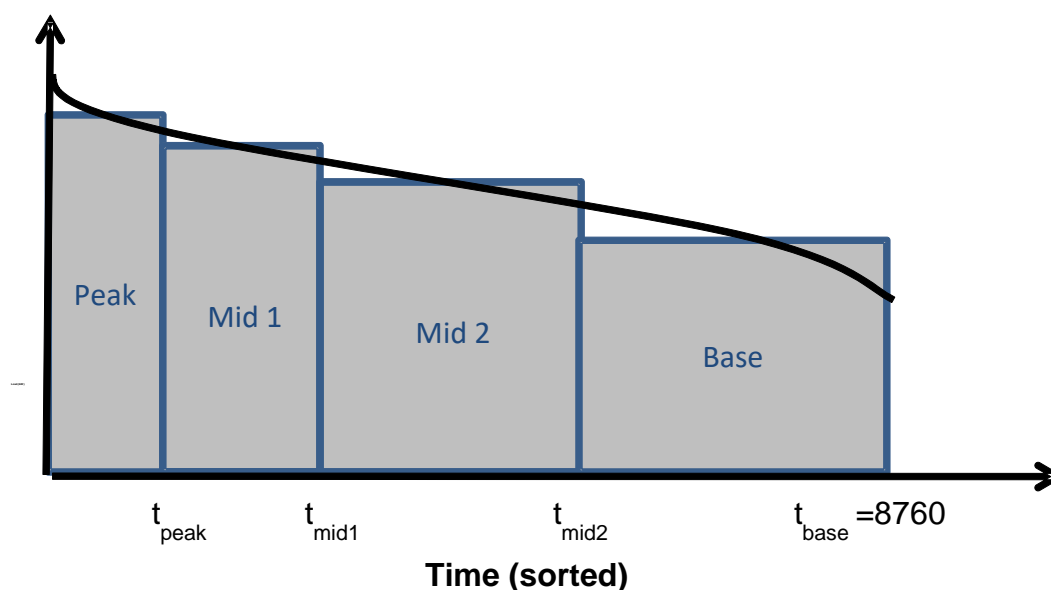
- Electricity prices must be high enough to cover the variable costs of all the plants operating in a region in a given year.
- If there are new capacity additions, then prices must be high enough to cover the full costs – fixed costs as well as variable costs – of these new entrants.

Derivation of a simplified merit order for thermal power plants

For each region, WEM breaks the annual electricity demand volume down into four segments:

- baseload demand, representing demand with a duration of more than 5944 hours per year;
- low-midload demand, representing demand with a duration of 3128 to 5944 hours per year;
- high-midload demand, representing demand with a duration of 782 to 3128 hours per year; and
- peakload demand, representing demand with a duration of less than 782 hours per year.

This results in a simplified four-segment load-duration curve for demand (Figure 4). For a fuller discussion of load-duration curves and how they are derived, please refer to the methodology document on the calculation of capacity credit for renewables.

Figure 4: Load-duration curve showing the four demand segments

This demand must be met by the electricity generation capacity of each region, which consists of variable renewables – technologies like wind and solar PV without storage whose output is driven by weather – and dispatchable plants (generation technologies that can be made to generate at any time except in cases of technical malfunction). In order to account for the effect of variable renewables on wholesale prices, the model calculates the probable contribution of variable renewables in each segment of the simplified load-duration curve. Subtracting the contribution of renewables from each segment in the merit order leaves a residual load-duration curve that must be met by dispatchable generators.

Calculation of average marginal cost in each merit order segment

Given the variable costs of all the plants in operation in each region, the WEM calculates a merit order of dispatchable plants in each region. This ranks all the plants in order from those with the lowest variable costs to the highest.

It then calculates which types of generator are used during each segment of the residual load-duration curve based on the merit order; i.e. plants with the lowest variable costs are given priority, and plants with the highest variable costs are used only in peak periods.

Once the generation from each plant has been allocated to the four segments of the merit order, the model calculates the marginal variable cost of generation in each segment by looking at average variable cost of the additional plants operating in each segment. For example, for the low-midload segment of the merit order, the model excludes plants that are also operating in the baseload period and calculates the average variable cost of the remainder. This gives a price for each merit order segment based on the average marginal variable cost of generators operating in that segment.

Given that the model assumes that new entrants must recover their full generation costs in addition to ensuring that all plants recover their variable costs, the model then calculates total revenues to all plants based on the segments in which they operate and the price in each segment. For example, a baseload plant would receive the peakload price for 782 hours of its operation, the high-midload price for $3128 - 782 = 2346$ hours of its operation, the low-midload price for $3128 - 782 = 2346$ hours and the baseload price for the rest of its operating hours. If there are new entrants, and if the price in any segment is too low to cover their costs, then the price in those segments is increased to the level required to justify new entry.

Calculation of wholesale price based on average marginal cost

Once a price has been calculated in each segment that satisfies the twin requirements of meeting all generators' variable costs and new entrants' full costs, the wholesale price level is then calculated as follows:

$$\text{Wholesale price} = \frac{\sum_{s=1}^4 (p_s \cdot d_s \cdot h_s)}{\sum_{s=1}^4 (d_s \cdot h_s)}$$

where s represents the four periods, p_s is the price in each segment (in \$/MWh), d_s is the demand level in each segment (in MW), and h_s is the number of hours in the period (in h). (Note that this results in a volume-weighted wholesale price, rather than a time-weighted price).

2.3.4 Subsidies

2.3.4.1 Subsidies to renewable energy

The model calculates for each region the subsidies to renewable energy – renewables-based electricity generation and biofuels – identifying its additional economic cost as the difference between the prices paid (assumed equivalent to the cost of production) per unit of renewable energy and the market value (or reference price) of substitutable technologies or fuels.

For the subsidies to renewables-based electricity generation, the additional economic cost is calculated for each renewable energy technology and for the amount of that technology installed in any given year, taking into account its levelised cost per unit of generation (in \$/MWh) and the wholesale electricity price for each year of its economic lifetime. Because the wholesale electricity price changes from year to year, the difference between the levelised cost and the wholesale price also changes every year. The average wholesale electricity price received by each technology also varies according to the simulated operations.

In the case of biofuels subsidies, we calculate the difference between the costs of biofuels production for ethanol and biodiesel and the projected price of the liquid fossil fuel equivalent, i.e. gasoline and diesel, before taxes. This cost increment is then multiplied by the volume of ethanol and biodiesel used in each year, for each region.

2.3.4.2 Subsidies to fossil fuels

The IEA measures fossil fuel consumption subsidies using a price-gap approach. This compares final end-user prices with reference prices, which correspond to the full cost of supply, or, where appropriate, the international market price, adjusted for the costs of transportation and distribution. The estimates cover subsidies to fossil fuels consumed by end-users and subsidies to fossil-fuel inputs to electricity generation.

The price-gap approach is designed to capture the net effect of all subsidies that reduce final prices below those that would prevail in a competitive market. However, estimates produced using the price-gap approach do not capture all types of interventions known to exist. They, therefore, tend to be understated as a basis for assessing the impact of subsidies on economic efficiency and trade. Despite these limitations, the price-gap approach is a valuable tool for estimating subsidies and for undertaking comparative analysis of subsidy levels across countries to support policy development (Koplow, 2009).

For more detail on fossil fuel consumption subsidies see also the 'documentation' section on the WEO website: <http://www.iea.org/weo/>.

3 Energy demand

All 25 model regions are modelled in considerable sectoral and end-use detail. Specifically:

- Industry is separated into six sub-sectors;
- Buildings energy demand is separated into six end-uses;
- Transport demand is separated into nine modes with considerable detail for road transport.

Total final energy demand is the sum of energy consumption in each final demand sector. In each sub-sector or end-use, at least six types of energy are shown: coal, oil, gas, electricity, heat and renewables. The main oil products – liquefied petroleum gas (LPG), naphtha, gasoline, kerosene, diesel, heavy fuel oil (HFO) and ethane – are modelled separately for each final sectors.

In most of the equations, energy demand is a function of activity variables, which again are driven by:

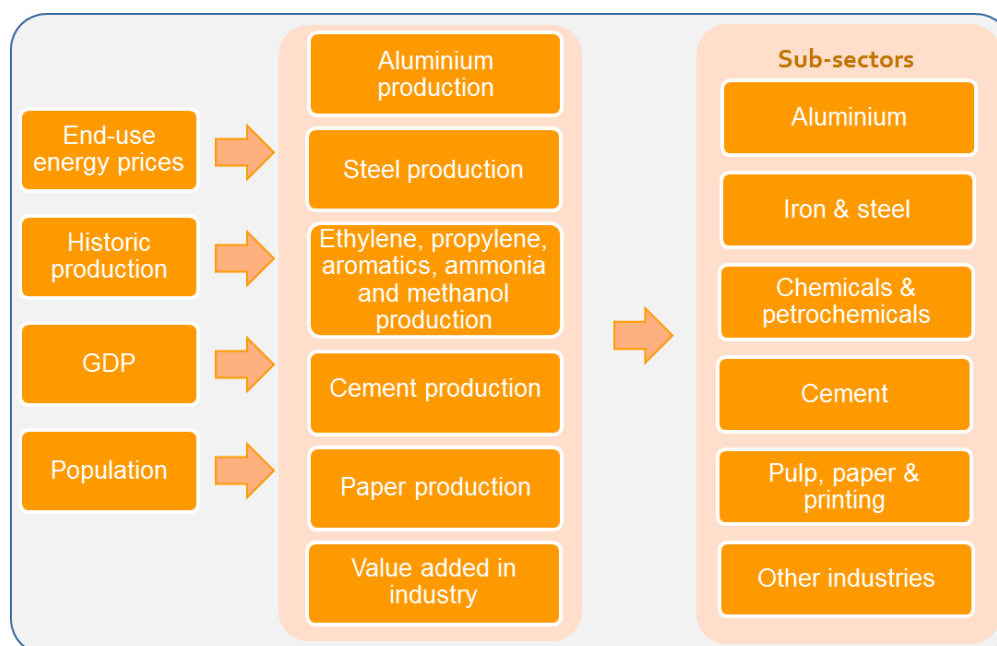
- *Socio-economic variables*: In all end-use sectors GDP and population are important drivers of sectoral activity variables.
- *End-user prices*: Historical time-series data for coal, oil, gas, electricity, heat and biomass prices are compiled based on the IEA Energy Prices & Taxes database and several external sources. Average end-user prices are then used as a further explanatory variable — directly or as a lag.

3.1 Industry sector

The industrial sector in the WEM is split into six sub-sectors: aluminium, iron and steel, chemical and petrochemical, cement, pulp and paper, and other industry⁴. The iron and steel sub-sector is modelled together with the sub-sectors of blast furnaces, coke ovens and own use of those two in the industry sector. However, in accordance with the IEA energy balances, in Annex A of *WEO-2018* energy demand from coke ovens and blast furnaces is not listed under industry, but under ‘other energy sector’. Similarly, petrochemical feedstocks are modelled as part of the chemical and petrochemical industry, but they are not included in industry in Annex A, but under final energy consumption in the category ‘other’.

Energy consumption in the industry sector is driven by the demand for specific products in the energy-intensive sectors – aluminium, iron and steel, chemicals and petrochemicals, cement, and pulp and paper – and by value added in industry for the non-specified industry sectors (Figure 5). Production of energy-intensive goods is econometrically projected for a specific year with the help of the following variables: population, end-use energy prices, value added in industry, per capita consumption of the previous year and a time constant. Historic production data is collected from a range of sources, including International Aluminium Institute (2017) (*aluminium*), World Steel Association (2017) (*steel*), METI (2014) (*ethylene, propylene and aromatics*), USGS (2017a) (*ammonia*), USGS (2017b) (*cement*), RISI (2017) and FAO (2017) (*paper*).

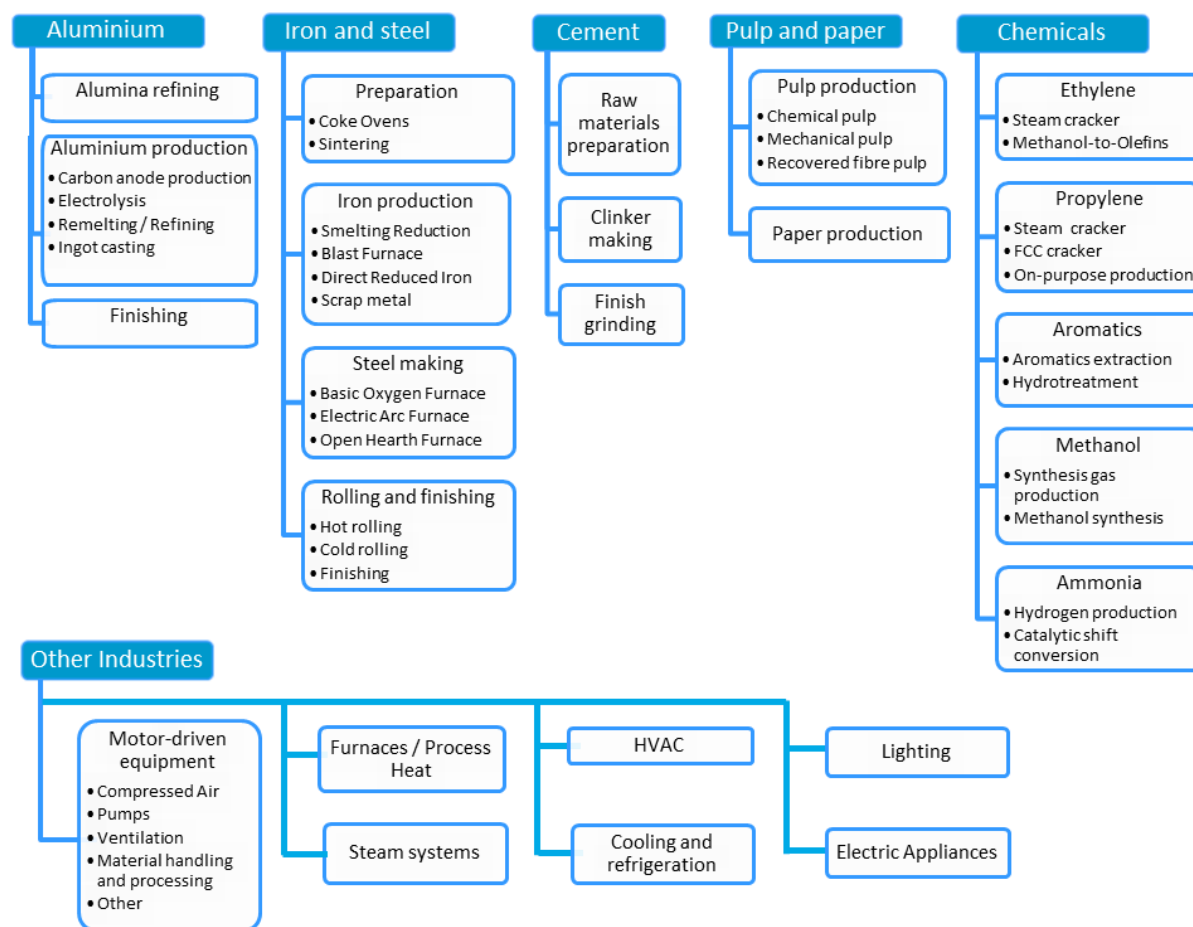
⁴Other industry is an aggregate of the following (mainly non-energy intensive) sub-sectors: non-ferrous metals, non-metallic minerals (excluding cement), transport equipment, machinery, mining and quarrying, food and tobacco, wood and wood products, construction, textile and leather, and non-specified.

Figure 5: Structure of the industry sector

Based on the projected production numbers it is possible to calculate the capacity necessary to satisfy the demand. Furthermore, we estimate current capacity and capacity vintage in each model region, which allows the calculation of retired capacity given our assumptions on average lifetime (IEA, 2011a). This allows us to determine the required capacity additions as the sum of replacing retired capacity and meeting demand increases in a specific year. Major energy efficiency improvements are generally limited in scope for existing industrial infrastructure. This is reflected in our modelling by restricting the adoption of energy-efficient equipment to newly installed capacity. However, we allow for early retirement of existing infrastructure in order to adopt more efficient infrastructure.

Final energy consumption in each sub-sector is calculated as the product of production projections and energy intensity of the manufacturing process. While the energy consumption per unit of output is fairly stable for existing infrastructure, the energy intensity of new capacity depends on the adoption of energy-efficient equipment and the level of energy prices.⁵ Technological efficiency opportunities are detailed by each industrial process for aluminium, iron and steel, five major product groups in chemicals and petrochemicals, cement, pulp and paper, and cross-cutting technologies in non-energy intensive sectors (Figure 6). Energy-efficient technologies are adopted as a function of their payback period and their potential penetration rate, which varies by scenario. Next to single equipment efficiency, systems optimisation and process changes represent further efficiency options integrated in the industry sector model. Process changes take the form of an increased use of scrap metal in the aluminium industry, increased use of scrap metal, direct reduced iron and electric arc furnaces in the iron and steel industry, a decreased clinker-to-cement ratio in the cement industry, and an increased use of recycled paper in the pulp and paper industry.

⁵ For more details on modelling energy efficiency potentials in industry, see Kesicki and Yanagisawa (2014).

Figure 6: Major categories of technologies by end-use sub-sector in industry

The data on energy-saving technologies is compiled from industry associations, individual companies and range of literature sources:

- **Aluminium:** Kermeli et al. (2015), Liu, Bangs and Müller (2013), Wen and Li (2014),
- **Iron and steel:** Dahlmann et al. (2010), Eurofer (2014), Hasanbeigi et al. (2013a), Hasanbeigi et al. (2013b), IEA CCC (2012), IPTS (2011), Morrow et al. (2013a), Oda et al. (2012), Okazaki and Yamaguchi (2011), Pardo et al. (2012), Schuhmacher and Sathaye (1998), US EPA (2010a), Worrell et al. (1999), Worrell et al. (2010)
- **Chemicals and petrochemicals:** Broeren et al. (2014), EC (2001), EC (2003), IEA (2013b), Neelis et al. (2008), Rafiqul et al. (2005), Ren, Patel and Blok (2008), Saygin et al. (2009), Saygin et al. (2011), Tian et al. (2012), Worrell et al. (2000), Zhou et al. (2010)
- **Cement:** APP (2009), CNI, IEL and Electrobras (2010a), CSI (2013), CSI and ECRA (2009), Hasanbeigi et al. (2010), Hasanbeigi et al. (2012), IEA (2013c), IIP and IFC (2014), Ke et al. (2012), Madloul et al. (2011), Morrow et al. (2013b), Moya et al. (2011), Oda et al. (2012), Tsinghua University (2008), US EPA (2010b), Worrell et al. (2008)
- **Pulp and paper:** CNI, IEL and Electrobras (2010b), EC (2010), Fleiter et al. (2012), Fracero et al. (2012), Kong, Hasanbeigi and Price (2013), Kramer et al. (2009), Martin et al. (2000), US EPA (2010c)

- **All industries:** Fraunhofer ISI and FfE (2003), Fraunhofer ISI et al. (2009), IEA (2007), IEA (2009), IEA (2012b), NEDO (2008), Neelis et al. (2012), UNIDO (2010), UNIDO (2011), Worrell and Neelis (2007)

Accounting for physical and technological constraints, the share of each energy source is projected on an econometric basis relying on the previous year's share, the fuel price change, the price change in the previous year and a time constant. In this context, electricity is separately modelled from fossil fuels, heat, biomass and waste because there are very limited possibilities to substitute electricity for another fuel or vice versa. However, a potential electrification of the industry sector is taken into account via wider process changes (e.g. increasing the share of electric arc furnaces in steel production). Fuel switches, for example from oil-based products to natural gas, are possible and modelled via a multiple logit model. First, a utility function is defined for each fuel:

$$V_{i,t} = \alpha_i * \frac{price_{i,t}}{price_{fuel\ average,t}} + \beta_{time} * t + \gamma_{adj}$$

with $i = coal, oil, natural\ gas, district\ heat\ and\ biomass$

where $V_{i,t}$ is the utility function of fuel i at year t , α_i is a regression coefficient for fuel i , $price_{i,t}$ is the fuel price of fuel i at year t and $price_{fuel\ average,t}$ is the weighted average price of all fuels at time t . β_{time} is a time constant (in general, this is set to zero) and γ_{adj} is an adjustment factor that represents non-price influences, such as fuel-specific policies.

In a next step, the choice probability is determined based on the utility function of each fuel:

$$\pi_{i,t} = \frac{\exp(V_{i,t})}{\sum_i \exp(V_{i,t})}$$

where $\pi_{i,t}$ is the choice probability of fuel i at time t .

The fuel share is eventually calculated taking into account the fuel share in the previous year and the choice probability:

$$share_{i,t} = share_{i,t-1} + \delta * (\pi_{i,t} - share_{i,t-1})$$

where $share_{i,t}$ stands for the share of fuel i in year t , and δ is between 0 and 1 and represents the adjustment speed.

For *WEO-2017*, heat supply capacities and production costs within industry have been made explicit and new and renewables technologies deployment modelling has been integrated into a single framework. This has been done together with adding one temperature dimension to the modelling, in the form five temperature levels (0-60°C, 60-100°C, 100-200°C, 200-400°C and above 400°C), defining potentials in which the different technologies can deploy, depending on their specific costs and performances at each temperature level. Deployment of these technologies is assessed against a counterfactual technology representing the average fossil-fuel-based technology that would otherwise be used that given year, through Weibull functions using the average levelized production costs of the different options and allowing for the calibration of inertia, policies and existing/lack of infrastructure.

3.1.1 Chemicals and petrochemicals sector

The chemicals and petrochemicals sector is characterised by a variety of products that can be produced via different pathways. Furthermore, in this sector, energy is used not only as a fuel but also as a feedstock. The complexity of the sector makes energy demand modelling notoriously difficult.

In the WEM, we have separately modelled the following intermediate products, which are the most energy-intensive ones to make:

- Organic chemicals
 - Petrochemicals:
 - Ethylene
 - Propylene
 - Aromatics (benzene, toluene and xylenes)
 - Methanol
- Inorganic chemicals
 - Ammonia

These product groups account for around half of total fuel consumption and for the vast majority of feedstock consumption. Products that make up the rest of petrochemical and chemical feedstock consumption are butadiene, butylene and carbon black. The distinction between fuel use and feedstock use is important as energy used as feedstock cannot be reduced through efficiency measures.

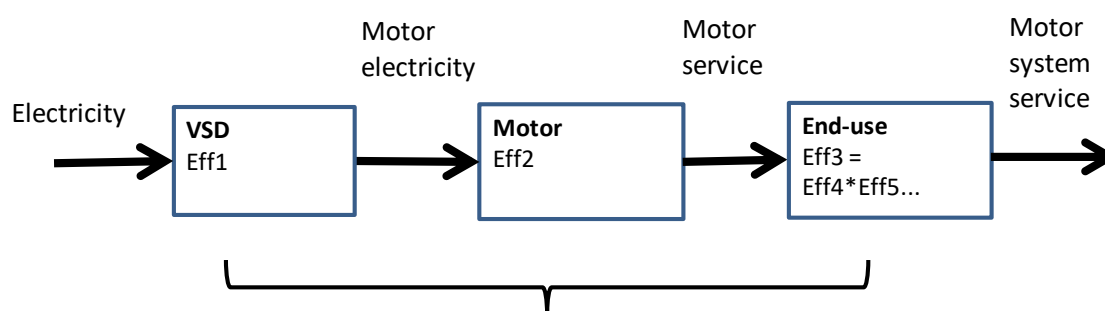
In order to analyse the energy consumption for these five major intermediate products, the following principal production routes have been implemented in the model:

- Steam cracking (for the production of ethylene, propylene and aromatics)
- Refinery streams (for the production of propylene from fluid catalytic cracking and aromatics from catalytic reforming)
- Propane dehydrogenation (for the production of propylene)
- Methanol-to-olefins (for the production of ethylene and propylene)
- Coal/biomass gasification and natural gas steam reforming (for the production of synthesis gas)
- Methanol synthesis (for the production of methanol from synthesis gas)
- Ammonia synthesis (for the production of ammonia from synthesis gas)

Since the specific energy consumption in steam cracking depends on the oil product being used, inputs into this process are divided into: ethane, liquid petroleum gas, naphtha and heavy fuel oil. As for the other sub-sectors, future production volumes are based on an econometric projection, but in addition the projection takes account of feedbacks from oil supply and the refinery modules to account for the availability of feedstock.

3.1.2 Motor efficiency

A sub-model for industrial electric motors (illustrated in Figure 7) was developed as part of an analysis of electric motor efficiency for *WEO-2016*. The driver for the model is the motor system service demand. This is driven by the projected value-added in the industry sector and can be thought of as the demand for motor system service. The model then has several steps to control efficiencies of three separate modules (being the end-use, the motor and a variable speed drive [VSD]). The efficiencies of these three steps multiplied with each other give the motor system efficiency, Eff0. Dividing the motor system service by Eff0 gives the electricity consumed in industrial electric motor systems.

Figure 7: Structure of the electric motor model

$$\text{Motor system efficiency, Eff}_0 = \text{Eff}_1 * \text{Eff}_2 * \text{Eff}_3$$

The end-use efficiency is calculated as a weighted average of efficiencies in four end-uses: pumps, fans, mechanical movement and compressors. For each of these four end-uses there is a stock model (with starting year 1980) with efficiencies of each vintage of normal and “efficient” devices. The share of sales of efficient devices is determined by the payback periods of such an investment, controlled by a Gompertz function. The end-use module includes the efficiency of a throttle, which represents the fact that in many motor systems, the outflow is controlled by with a throttle or a damper, thereby bringing the system efficiency down.

3.1.3 Material efficiency

Beyond energy efficiency technologies and measures, the WEM industry model can also represent material efficiency strategies, enabling further energy savings. Given the large share of energy costs in production costs in energy-intensive sectors, the potentials to increase energy efficiency are in general more limited compared with less energy-intensive industries. Possible material efficiency strategies to limit the growth of these sectors’ energy consumption are:

- Re-use materials: Use of post-consumer scrap directly (i.e. without re-melting) for the same or other applications.
- More efficient production: Reduce the losses in the product process by increasing manufacturing and semi-manufacturing yield rates.
- Light-weighting products: Produce the same product with a lower average mass per product.
- Increase recycling: Increase collection rates of post-consumer scrap.
- Divert fabrication scrap: Instead of remelting fabrication scrap, it can be used for other applications.
- More intensive use of products: Use material-intensive goods more intensively, e.g. by sharing a car or using a building for a higher share of the day.
- Longer life times: Extend the life time of material components in products.

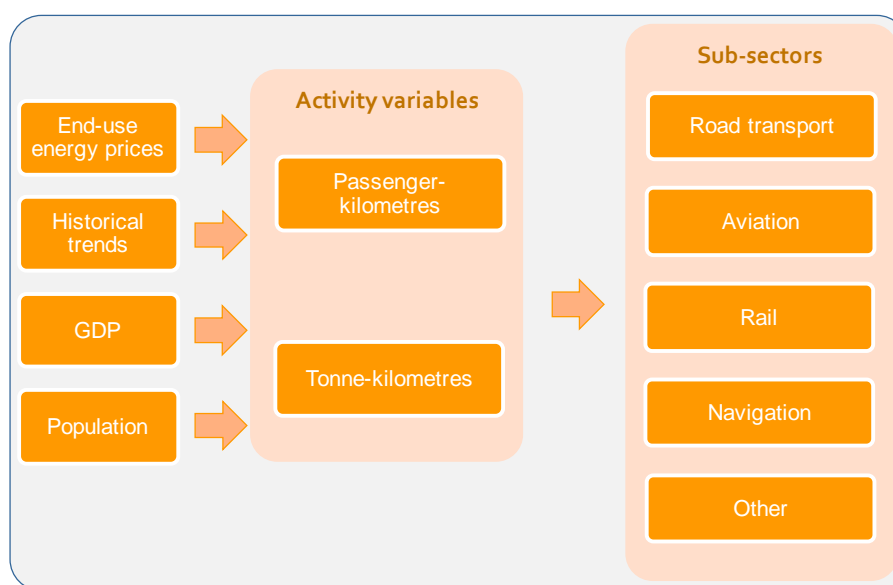
For this purpose, material flow models for aluminium and steel demand enable realistic assumptions for these material efficiency strategies to be incorporated into the model, helping the assessment of future demand and the amount of scrap metal (semi-manufacturing, manufacturing and post-consumer scrap) available for metals production. This modelling work builds mainly on the following literature: Cullen et al. (2012), Cullen and Allwood (2013), Liu et al. (2013) and Pauliuk et al. (2013). The scope of this approach is limited to materials and energy demand within the respective industry sectors. It does not analyse the implications on energy consumption upstream, in mining or the transportation of materials, nor the consequences for downstream energy consumption, e.g. from more efficient, lighter cars. Nor does the study analyse the potential for energy savings from substituting materials, e.g. using plastics for metals. This material efficiency

module can be used either for dedicated analysis as in *WEO-2015*, or for use in very stringent climate scenarios such as the “well-below 2 degrees” scenario.

3.2 Transport sector

The transportation module of the WEM consists of several sub-models covering road transport, aviation, rail and shipping navigation (Figure 8). The WEM fully incorporates a detailed bottom-up approach for the transport sector in all WEM regions.

Figure 8: Structure of the transport sector



Note: ‘Other’ includes pipeline and non-specified transport.

For each region, activity levels such as passenger-kilometres and tonne-kilometres are estimated econometrically for each mode of transport as a function of population, GDP and end-user price. Transport activity is linked to price through elasticity of fuel cost per kilometre, which is estimated for all modes except passenger buses and trains and inland navigation. This elasticity variable accounts for the “rebound” effect of increased car use that follows improved fuel efficiency. Energy intensity is projected by transport mode, taking into account changes in energy efficiency and fuel prices. The road module is calibrated to historical fuel use, i.e. the gasoline, diesel, natural gas and electricity, which is updated every year and ensure that the model reflects closely on recent developments in terms of vehicle stocks, vehicle mileages and vehicle efficiencies. A gap factor is used to account for differences between test cycle fuel consumption and on-road fuel use.

3.2.1 Road transport

Road transport energy demand is broken down among passenger light duty vehicles (PLDVs), light commercial vehicles (LCVs), buses, medium trucks, heavy trucks and two- and three-wheelers. The model allows fuel substitution and alternative powertrains across all sub-sectors of road transport. The gap between test and on-road fuel efficiency, i.e. the difference between test cycle and real-life conditions, is also estimated and projected.

As the largest share of energy demand in transport comes from oil use for road transport, the WEM contains technology-detailed sub-models of the total vehicle stock and the passenger car fleet. In its origin, the stock projection model is based on an S-shaped Gompertz function, proposed in Dargay et al. (2006). This model

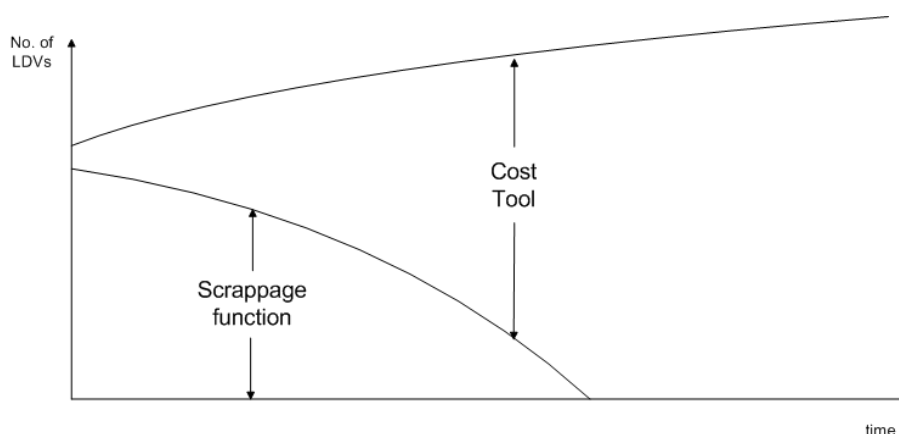
gives the vehicle ownership based on income (our GDP assumptions through to 2040) and 2 variables: the saturation level (assumed to be the maximum vehicle ownership of a country/region) and the speed at which the saturation level is reached. The equation used is:

$$V_t = y e^{ae^{bGDP_t}}$$

where V is the vehicle ownership (expressed as number of vehicles per 1,000 people), y is the saturation level (expressed as number of vehicles per 1,000 people), a and b are negative parameters defining the shape of the function (i.e. the speed of reaching saturation). The saturation level is based on several country/region specific factors such as population density, urbanisation and infrastructure development. Passenger car ownership is then calculated based on the detailed vehicle fleet data in the IEA Mobility Model (MoMo) plus other regional statistics. Using the equation above, changes in passenger car ownership over time are modelled, based on the average current global passenger car ownership. Both total vehicle stock and passenger vehicle stock projections are then derived based on our population assumptions. Projected vehicle stocks and corresponding vehicle sales are then benchmarked against actual annual vehicle sales and projected road infrastructure developments. The resulting vehicle stock projections can therefore differ from those that would be derived by the use of the Gompertz function alone.

The analysis of **passenger light-duty vehicle (PLDV)** uses a cost tool that guides the choice of drivetrain technologies and fuels as a result of their cost-competitiveness. The tool acts on new passenger-LDV sales as depicted in Figure 9, and determines the share of each individual technology in new passenger LDVs sold in any given year.

Figure 9: The role of passenger-LDV cost model



The purpose of the cost tool is to guide the analysis of long-term technology choices using their cost-competitiveness as one important criterion. The tool uses a logit function for estimating future drivetrain choices in passenger LDV.⁶ The share of each PLDV type j allocated to the passenger light duty vehicle market is given by

$$Share_j = \frac{b_j P_{PLDV_j}^{r_p}}{\sum_j (b_j P_{PLDV_j}^{r_p})}$$

where

⁶Originally developed to describe the growth of populations and autocatalytic chemical reactions, logit functions can be applied to analyse the stock turnover in different sectors of the energy system. Here, it uses the cost-competitiveness of technology options as an indicator for the pace of growth.

- P_{PLDV_j} is the annual cost of a vehicle, including annualised investment and operation and maintenance costs as well as fuel use
- R_p is the cost exponent that determines the rate at which a PLDV will enter the market
- b_j is the base year share or weight of $PLDV_j$

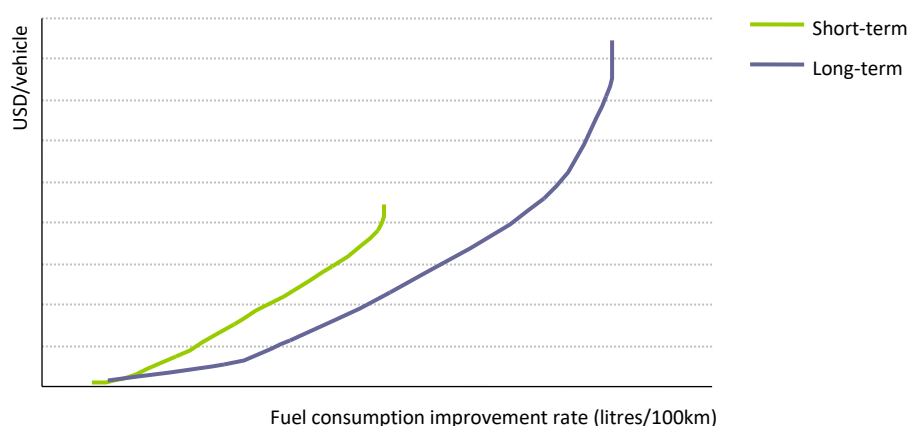
The cost database in the cost tool builds on an analysis of the current and future technology costs of different drivetrains and fuel options, comprising the following technology options:

- conventional internal combustion engine (ICE) vehicles (spark and compression ignition)
- hybrid vehicles (spark and compression ignition)
- plug-in hybrids (spark and compression ignition)
- electric cars with different drive ranges
- hydrogen fuel cell vehicles

The model takes into account the costs of short- and long-term efficiency improvements in personal transport distinguishing numerous options for engine (e.g. reduced engine friction, the starter/alternator, or transmission improvements) and non-engine measures (e.g. tyres, aerodynamics, downsizing, light-weighting or lighting). In addition, it uses projections for the costs of key technologies such as batteries (NiMH and Li-ion) and fuel cells. The pace of technology cost reductions is then calculated using learning curves at technology-specific learning rates.

The cost analysis builds on a comprehensive and detailed review of technology options for reducing fuel consumption. The database was reviewed by a panel of selected peer-reviewers, and feeds into the cost tool. The cost database is constantly reviewed and takes account of recent research.

Road freight transport vehicles can be broadly classified into light-commercial vehicles (<3.5t), trucks (3.5t – 16t) and heavy trucks (>16t). For the latter two categories, WEM comprises two detailed sub-models to guide the development of average fuel economy improvements on the one hand, and technology choices on the other hand. For the former, the model endogenises the decision of investments in energy efficiency by taking the view of rationale economic agents on the basis that minimising costs is a key criterion for any investment decision in this sector. Using the efficiency cost curves of NRC, the model calculates the undiscounted payback period of an investment into more fuel-efficient trucks and heavy trucks. The model then allows for investments where the calculated payback period is shorter than an assumed minimum payback period that is required by fleet operators (generally assumed between 1 and 3 years, depending on the region). The problem is solved in an iterative manner as the model seeks to deploy the next efficiency step on the efficiency cost curve as determined by literature, but may use efficiency improvement levels in between individual steps on the efficiency cost curve. An example of an efficiency cost curve is depicted in Figure 10.

Figure 10: Illustration of an Efficiency Cost Curve for Road Freight

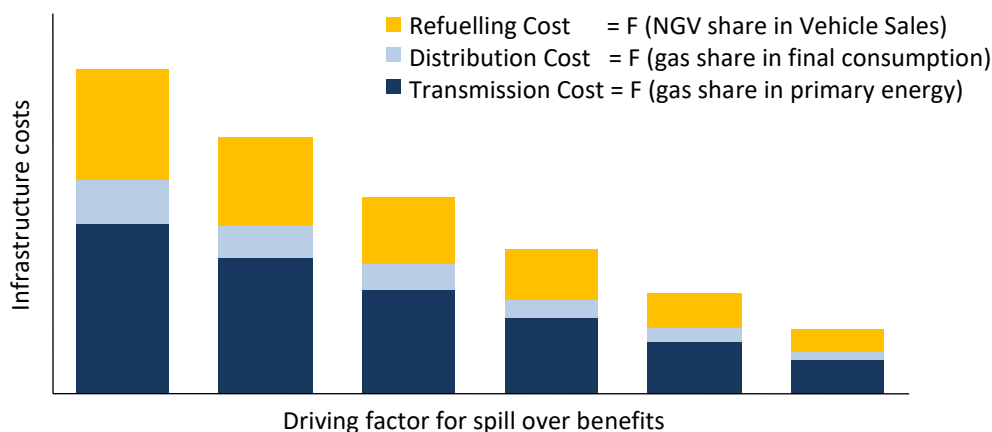
In a second step, the model simulates the cost effectiveness of a conventional internal combustion engine vehicle against other competing options such as hybrid vehicles and natural gas vehicles. The simulation is guided by the use of a Weibull function. In *WEO-2018*, alternative powertrains for medium- and heavy-duty trucks have been implemented in the WEM: fuel cell, battery electric and plug-in hybrid electric.

In order to assess the problems created due to chicken-and-egg-type of situations when it comes to the deployment of those alternative fuels in transport that require a dedicated refuelling infrastructure, and to better reflect potential spill-over effects of the use of such alternative fuels in other sectors of the energy system, the WEM has two dedicated sub-models, one covering natural gas infrastructure and the other electricity-related refuelling infrastructure. In principle, both modules seek to quantify the costs and benefits of increased infrastructure availability for transmission and distribution of these alternative fuels. Thus, in the case of natural gas, an enhanced share of natural gas use in primary energy demand (for example in the power generation sector) would lead to the development of a transmission grid in the economy; and similarly, an increased share of natural gas in final energy consumption by end use sectors (for example, in industry or buildings) will lead to an expanded distribution grid close to the consumption centres, thereby impacting the overall availability of natural gas in the economy and simultaneously driving down the transmission and distribution costs for all consumers, including the transportation sector. Moreover, an increased share of natural gas vehicles (NGVs) in total vehicle sales in the region would gradually improve the development and utilization of a refuelling network due to increased density of vehicles served per station, thereby reducing the average cost of refuelling. This relationship is thus implemented as a positively reinforcing loop, wherein increased penetration of natural gas (in all other sectors, not just transport) and natural gas vehicles helps driving down the overall refuelling infrastructure costs. In essence, the relationship of these spill-over benefits can be illustrated as in Figure 11.

For the case of electric vehicles, availability of transmission and distribution grid is less of an issue, especially in OECD countries, thanks to the already existing widespread use of electricity in different end use sectors (especially buildings). However, the availability of electric recharging infrastructure is one of the important constraints in this case, and hence it is important to determine how a reduction in refuelling costs could influence the possibility for oil substitution in road transport. Therefore, the electric vehicle (EV) sub-module assesses the cascading effect of an increased share of electric vehicles in overall vehicle sales on bringing down the refuelling costs. Detailed cost curves were prepared outlining the reduction of refuelling costs with the increase in overall vehicle stock of electric vehicles. These cost curves were provided as an exogenous input to the model, so as to continuously adjust the refuelling costs as the share of EV sales rises in the future.

Finally, based on projections of the average fuel consumption of new vehicles by vehicle type, the road transport model calculates average sales and stock consumption levels (on-road and testcycle) and average emission levels (in grammes of CO₂ per kilometre) over the projection period. It further determines incremental investment costs relative to other scenarios and calculates implicit CO₂ prices that guide optimal allocation of abatement in transport.

Figure 11: Refuelling infrastructure cost curve (illustrative)



3.2.2 Aviation

Aviation is among the fastest growing transport sectors. The aviation model is updated in collaboration with the IEA's Energy Technology Perspectives team which maintains the Mobility Model (MoMo). The model aims at assessing air traffic measured in revenue passenger kilometres (RPKs) and for passenger travel and revenue tonne-kilometres (RTK) for cargo. RPKs refer to the number of passengers which generate revenue multiplied by the kilometres they fly. RTKs refer to the number of tonnes carried which generate revenue multiplied by the kilometres they are flown. A detailed review of publically available historical data for the aviation sector was conducted to update the historical database of WEM and MoMo. It includes data from the International Civil Aviation Organization, aircraft manufacturers such as Airbus, Boeing and Embraer, and the Japan Aircraft Development Corporation. As a result, RPKs were estimated at 5.8 trillion in 2013, while RTKs were at around 0.2 trillion.

Future RPK and RTK growth is guided by projections of various factors, using growth in per capita income by region as a main driver:

- the number of flights per year and capita by model region, which grows as a function of population and income growth ;
- the average flight distances by model region, which gradually declines on a global level in line with recent trends (although with differences by model region); and
- the average flight occupancy, which is assumed to remain constant at current levels.

To assess future fuel consumption as a result of RPK and RTK growth, the model projects the resulting fuel intensity that global fuel consumption growth complies with an annual average fuel efficiency improvement of RPK growth of 2% by 2020 and an aspirational global fuel efficiency improvement rate of 2% per year from 2021 to 2050, as expressed by the Assembly of the International Civil Aviation Organization (ICAO). A further sub-model calculates investment costs and marginal abatement costs split by the types of abatement measure.

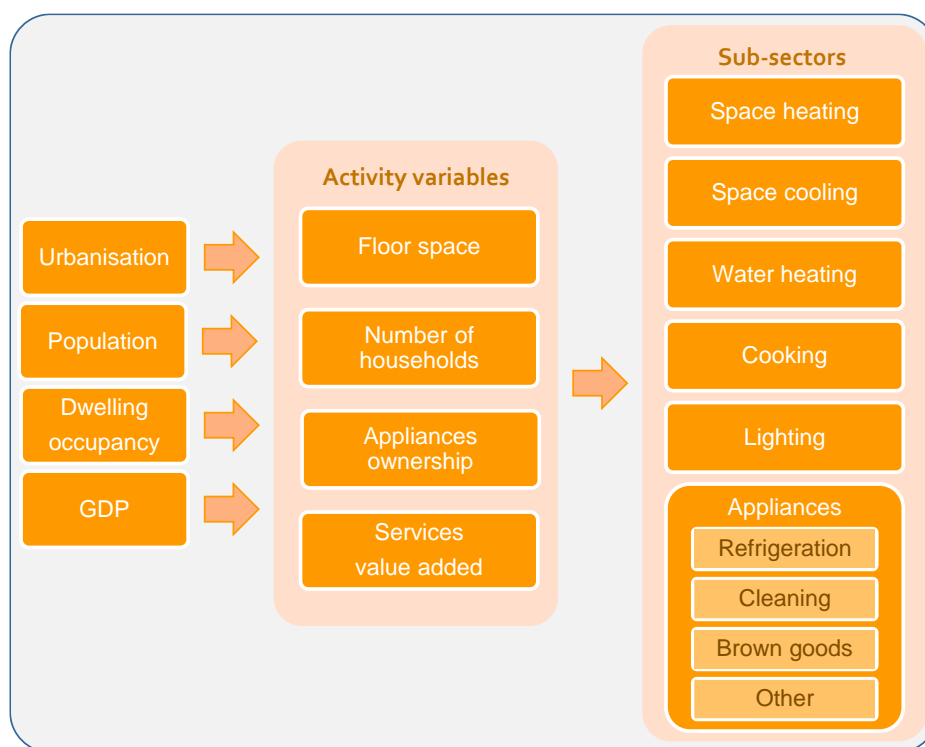
3.2.3 Maritime

In collaboration with the IEA's Energy Technology Perspectives team, which maintains the IEA Mobility Model, a completely new approach has been implemented in the WEM for *WEO-2016*. The aim of this overhaul was to have a better understanding of maritime freight demand from a bottom-up perspective, which is driven by projections of maritime trade. In the previous approach, we regarded energy demand for international maritime transport from a top-down perspective driven by growth in GDP PPP. The new bottom-up structure is based on the ASIF (Activity, Structure, Intensity and Fuel use) framework (Schipper, 2010) to assess energy demand and CO₂ emissions by region and ship type.

The activity variable represents the maritime trade demand in tonne-kilometre, i.e. tonnes carried multiplied by number of kilometres they are shipped. It covers global physical flows of maritime trade of 19 commodity types, by origin-destination points between 26 regions. Physical and monetary trade numbers and projections (2010-2050) were derived from the International Transport Forum freight model (Martinez et al., 2014) and revised to reflect changes in value to weight ratios of energy products. The data were aggregated to account for five ship types (oil tankers, bulk carriers, general cargo, container ships and others). The structure variable is interpreted as the load factor, i.e. the average capacity utilization per ship per trip, which allows deriving the vehicle-kilometres projected for each region and for each ship type. Load factor projections are based on historically observed growth rates of the average size of the different ship types, which are published by UNCTAD. The capacity utilization factor is kept constant. Furthermore, the base year energy intensity values are derived from the IMO 3rd GHG study (IMO, 2014). In the New Policies Scenario, projections of the energy intensity variable take into account the effect of Energy Efficiency Design Index (EEDI), introduced by the International Maritime Organisation (IMO). The EEDI mandates a minimum 10% improvement in the energy efficiency per tonne-km of new ship designs from 2015, 20% from 2020 and 30% from 2025 to 2030. These improvements are benchmarked against the average efficiency of ships built between 1999 and 2009. In the Sustainable Development Scenario, energy efficiency improvements are assumed to converge towards the maximum efficiency improvement potentials, which were assessed for each type of ship. Lastly, combining the activity, structure and energy intensity variable determines the final energy consumption by region and by ship type. Multiplying this number with the CO₂ emission factors of the different fuels modelled (heavy fuel oil, marine diesel oil, LNG and biodiesel) gives the total CO₂ emissions.

3.3 Buildings sectors

The buildings sector module of the WEM is subdivided into the residential and services sectors, both having a similar structure (Figure 12). Population, GDP and dwelling occupancy drive the activity variables, such as floor space, appliance ownership, number of households (residential sector) and value added (in the services sector).

Figure 12: Structure of the buildings sector

In the residential and services sectors, energy demand is further subdivided into six standard end uses in buildings, namely space and water heating, appliances (divided into four different categories: refrigeration – fridge and freezer-, cleaning – washing, drying machines and dish washers, brown goods – TVs and computers, and other appliances), lighting, cooking and space cooling. These sub-modules project final energy consumption from the base year to 2040 in three steps.

In a first step, the demand for an energy service, *i.e.* the useful energy demand, is determined, based on the activity variables.

$$\text{End use service demand} = \text{Activity variable} * \text{intensity}$$

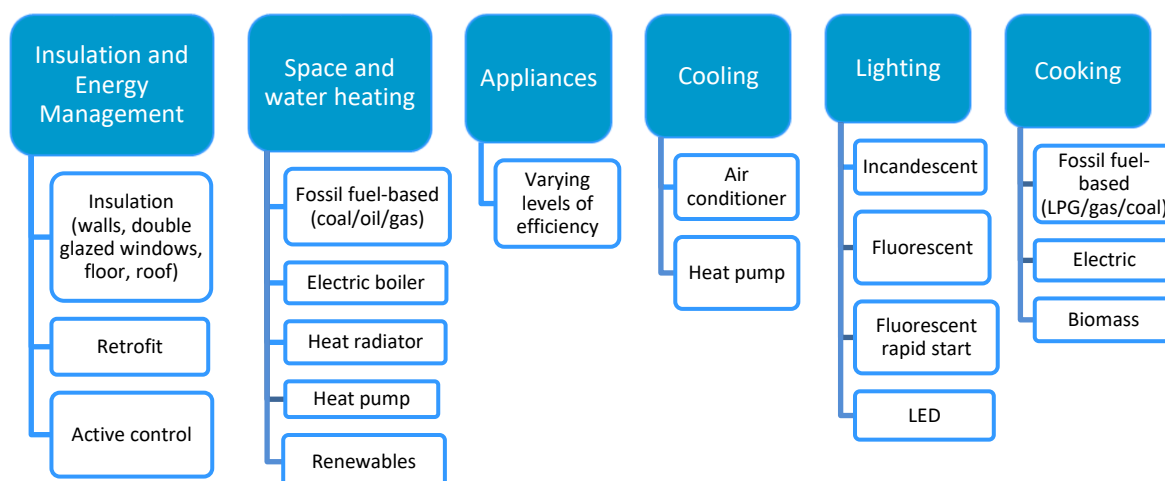
Here, activity refers to the main driver of the energy service demand – for the residential sector it is floor space area, people per household, and appliances ownership; and for services, it is valued added by the service sector. Intensity refers to the amount of energy service (e.g. space heating) needed per unit of activity variable (*e.g.* floor space). The activity variables are projected econometrically, based on historical data and linking to socio-economic drivers such as GDP and population. For each end use, the intensity variable is projected using the historical intensity and adjusting, for each projection year, to the change in average end-user fuel prices (using price elasticity) and change in average per capita income (using income elasticity). In the specific case of space heating and cooling, the intensity projections are also adjusted for historical variations in temperature. The impact of climate change on space heating and cooling demand can be included as well. Based on the anticipated change in heating and cooling degree days due to climate change, the increase in heating and cooling demand is quantified (McNeil and Letschert, 2007). Existing policies related to retrofit and insulation on existing buildings are also taken into account, as a higher level of retrofit and insulation results in a lower level of energy service demand.

Multiplying the activity by the intensity gives the end-use service demand (useful energy consumed). Thus, the incremental energy service demand from year to year could be an outcome of increased demand for service (largely in the case of developing economies, where demand is still evolving), or the retirement of old

units according to equipment retirement rates (as is the case in a majority of advanced economies). Both result in a need for new equipment.

In a second step, the technologies to supply the end-use service demand are chosen. For each end use, there is a detailed set of technologies available to the model (Figure 13). Within each technology option, for example a gas boiler, there are several types, representing the varying levels of efficiency and the associated investment cost. Additionally, there is a possibility to switch technologies, whereby heat-pumps could be used for space heating, instead of gas boilers.

Figure 13: Major categories of technologies by end-use subsector in buildings



The technology choice is made based on relative costs, efficiencies of the technologies and policy constraints, if any. The share of technologies is allocated by a Weibull function based on their specific costs per unit of service demand supplied, which includes investment costs, operating and maintenance costs, and fuel costs. The routine allocates the different technologies to satisfy the new service demand for every year over the *Outlook* period. This allocation is subject to upper and lower boundaries, reflecting real-world constraints such as technology availability and adoption, policies, and market barriers. Other measures to reduce end-use service demand, such as insulation and active control, are included in the technology allocation routine: they are deployed where they are economically viable.

To assess equipment and appliance efficiency, and related costs, we consulted with a large number of companies, experts and research institutions at the national and international levels. We also conducted an extensive literature review to catalogue technologies that are now used in different parts of the world and to judge their probable evolution (Anandarajah, *et al.*, 2011; Econoler, *et al.*, 2011; IEA, 2010; IEA, 2011b; IEA, 2012b; Kannan, *et al.*, 2007; Waide, 2011; IEA, 2013a; IEA2014b). The efficiency potential for electrical appliances has been determined using the BUENAS (Bottom-Up Energy Analysis System) model, an international appliance policy model developed by Lawrence Berkeley National Laboratory (LBNL). BUENAS covers thirteen economies that together account for 77% of global energy consumption, and twelve different end-uses, including air conditioning, lighting, refrigerators and industrial motors (LBNL, 2012). The assessment of efficiency potential in the services sector buildings also benefitted from preliminary estimates available from GBPN (Global Buildings Performance Network) and CEU (Central European University) study on buildings (GBPN and CEU, 2012).

In a third step, total final energy consumption in the residential and service sector is obtained based on the efficiencies of existing and new building equipment. Efficiency represents the amount of energy needed to meet a unit of service demand, and thus represents the technical performance of the equipment or appliances. Final energy consumption in the buildings sector is a summation of the sub-sectoral energy consumed by the total technology stock, which includes the historical (declining) stock of appliances and equipment, and the new technologies added every year over the *Outlook* period by the technology allocation routine.

$$\text{Final energy consumption} = \frac{1}{\eta} * \text{End use service demand}$$

At the same time, investments in all technology additions, as well as insulation, retrofit, and automation and control measures, are calculated. Carbon emissions related to the buildings sector are also calculated.

The buildings module is directly linked to the access (electricity access and clean cooking access) module to take into account the growth of electricity and of alternative fuels or stoves for cooking (see Section 9).

3.4 Demand-side response

While demand-side integration measures such as energy efficiency and electrification are long-standing components of the WEM, to assess demand-side response a new tool has been developed, since measurement of demand-side response requires a higher temporal resolution. To assess the potential amount of flexibility in end-use electricity demand that might be used to facilitate higher penetration of variable renewables, a three-step methodology was used. The first was to assess temporarily the load profile for each sector and subsector or end-use (residential and services (e.g. space heating, water heating.), industry (e.g. steel, chemicals industry), transport (e.g. road and rail) and agriculture) for every 24 hours of 36 typical days (weekday, Saturday and Sunday of each month). The aggregate electricity demand of each end-use or subsector temporarily was matched to the total load profile of a given country⁷. An example of the load aggregation is displayed in Figure 14: .

The second step was to assess the share of demand that is flexible in each end-use. This share is the product of three flexibility factors, sheddability, controllability and acceptability (Ookie Ma, 2013):

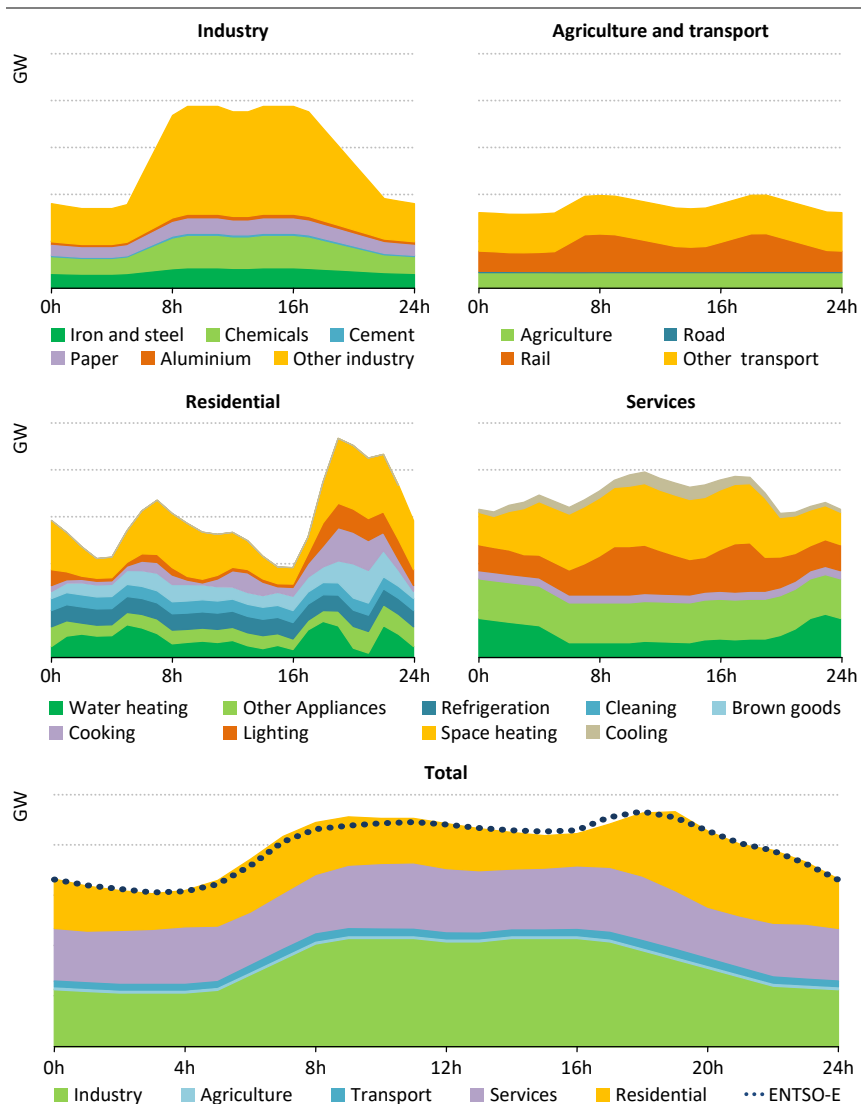
- Sheddability: Share of the load of each end-use that can be shed, shifted or increased by a typical DSR strategy.
- Controllability: Share of the load of each end-use which is associated with equipment that has the necessary communications and controls in place to trigger and achieve load sheds/shifts.
- Acceptability: Share of the load for a given end-use which is associated with equipment or services where the user is willing to accept the reduced level of service in a demand-response event in exchange for financial incentives.

This framework enables scenarios to consider demand flexibility from various technologies and at varying levels of social acceptability.

The third step was to integrate the DSR profiles in the hourly model to determine the load that can be shifted, given market conditions in the region analysed.

⁷ Data from ENTSO-E, PJM, ERCOT, MISO, NEISO, NYISO were used to replicate respectively the overall load curves of European Union, United States and India.

Figure 14: Illustrative load curves by sector for a weekday in February in European Union compared to the observed load curve by ENTSO-E in 2014



The load profile is an aggregation of the sectoral load profiles for typical days of the year

Note: ENTSO-E represents the aggregated load curve for the 28 European Union countries. Sources: (ENTSO-E, 2016); IEA analysis.

4 Power generation and heat plants

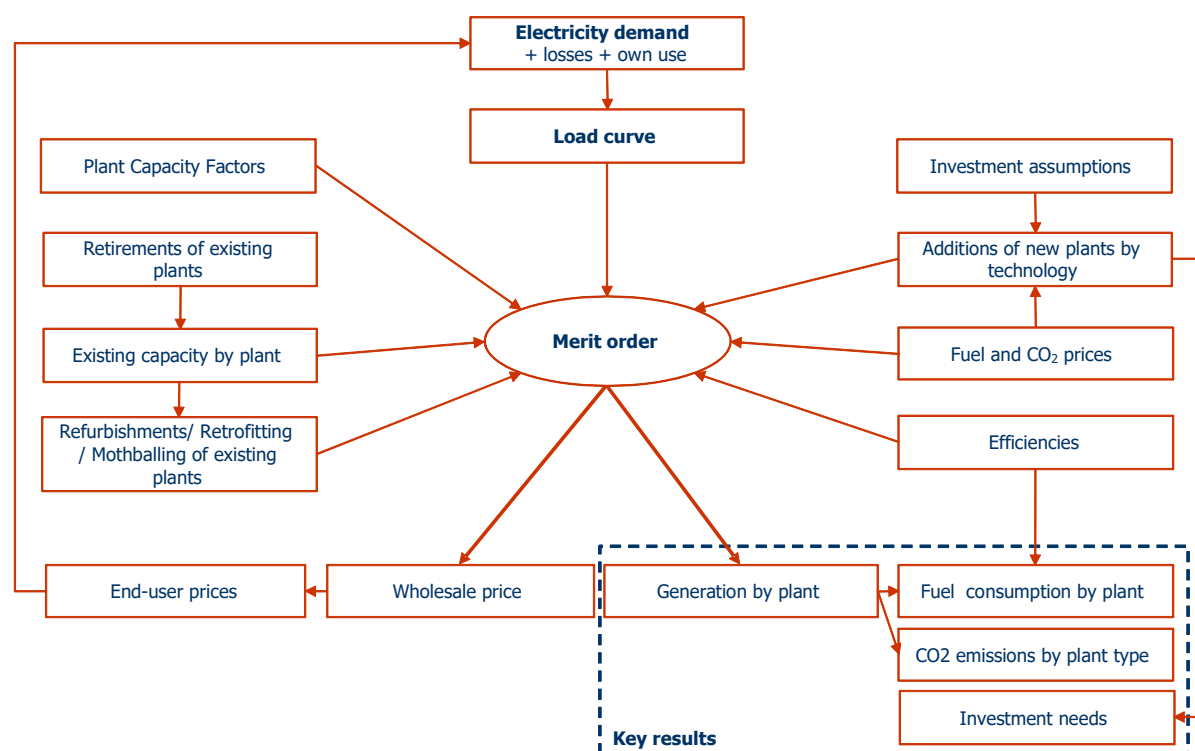
Based on electricity demand, which is computed in all demand sectors (described in section 3), the power generation module calculates the following:

- Amount of new generating capacity needed to meet demand growth and cover retirements and maintain security of supply.
- Type of new plants to be built by technology.
- Amount of electricity generated by each type of plant to meet electricity demand, cover transmission and distribution losses and own use.
- Fuel consumption of the power generation sector.
- Transmission and distribution network infrastructure needed to meet new demand and replace retiring network assets.
- Wholesale and end-use electricity prices.
- Investment associated with new generation assets and network infrastructure.

4.1 Electricity generation

The structure of the power generation module is outlined in Figure 15. The purpose of the module is to ensure that enough electrical energy is generated to meet the annual volume of demand in each region, and that there is enough generating capacity in each region to meet the peak electrical demand, while ensuring security of supply to cover unforeseen outages.

The model begins with existing capacity in each region, which is based on a database of all world power plants. The technical lifetimes of power plants are assumed to range between 45 and 60 years for existing fossil-fuel plants and nuclear plants (unless otherwise specified by government policies). The lifetimes of wind and solar PV installations are assumed to have a distribution centred around 25 years, ranging from 20 to 30 years; hydropower projects 50 years; and bioenergy power plants 25 years.

Figure 15: Structure of the power generation module

4.1.1 Capacity additions

The model determines how much new generation capacity is required annually in each region by considering the change in peak demand compared to the previous year, retirements of generation capacity during the year, and any increase in renewable capacity built as the result of government policy. Installed generating capacity must exceed peak demand by a security-of-supply margin; if this margin is not respected after changes in demand, retirements, and renewables additions, then the model adds new capacity in the region. In making this calculation, the model takes into account losses in transmission and distribution networks and electricity used by generation plants themselves.

Because of the stochastic nature of the output of variable renewables such as wind and solar PV, only a proportion of the installed capacity of these technologies can be considered to contribute to the available generation margin. This is reflected in the modelling by the use of a capacity credit for variable renewables. This capacity credit is estimated from historical data on hourly demand and hourly generation from variable renewables in a number of electricity markets, and it reflects the proportion of their installed capacity that can reliably be expected to be generating at the time of peak demand.

When new plants are needed, the model makes its choice between different technology options on the basis of their regional value-adjusted levelised cost of electricity (VALCOE), which are based on the levelised cost of electricity (LCOE), also referred to as the long-run marginal cost (LRMC). The LRMC of each technology is the average cost of each unit of electricity produced over the lifetime of a plant, and is calculated as a sum of levelised capital costs, fixed operation and maintenance (O&M) costs, and variable operating costs. Variable operating costs are in turn calculated from the fuel cost (including a CO₂ price where relevant) and plant efficiency. Our regional assumptions for capital costs are taken from our own survey of industry views and

project costs, together with estimates from NEA/IEA (2010). The weighted average cost of capital (pre-tax) is assumed to be 8% in the OECD and 7% in non-OECD countries.

The LRMIC calculated for any plant is partly determined by their utilisation rates. The model takes into account the fact that plants will have different utilisation rates because of the variation in demand over time, and that different types of plants are competitive at different utilisation rates. (For example, coal and nuclear tend to be most competitive at high utilisation rates, while gas and oil plants are most competitive at lower utilisation rates).

The specific numerical assumptions made on capital costs, fixed O&M costs, and efficiency can be found on the WEO website: <http://www.worldenergyoutlook.org/weomodel/investmentcosts/>.

The levelised cost module computes LRMICs (or LCOEs) for the following types of plant:

- Coal, oil and gas steam boilers with and without CCS;
- Combined-cycle gas turbine (CCGT) with and without CCS;
- Open-cycle gas turbine (OCGT);
- Integrated gasification combined cycle (IGCC);
- Oil and gas internal combustion;
- Fuel cells;
- Bioenergy;
- Geothermal;
- Wind onshore;
- Wind offshore;
- Hydropower (conventional);
- Solar photovoltaics;
- Concentrating solar power; and
- Marine

Regional LRMICs are also calculated for nuclear generation but additions of nuclear capacity are subject to government policies.

4.1.2 Generation volumes

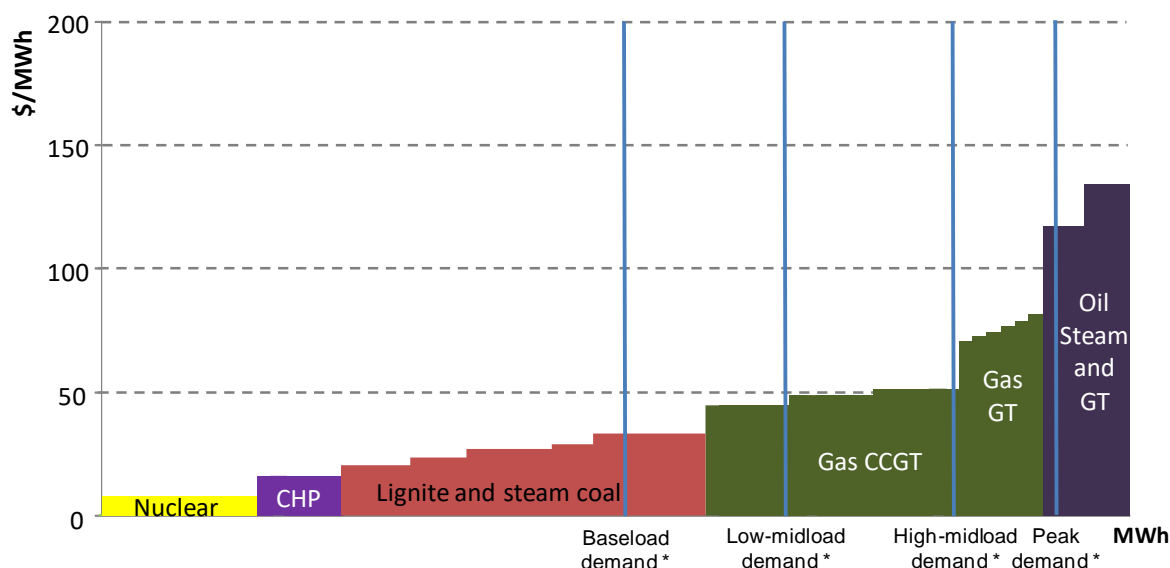
For each region, the model determines the generation from each plant based on the capacity installed and the level of electricity demand. Demand is represented as four segments:

- baseload demand, representing demand with a duration of more than 5944 hours per year;
- low-midload demand, representing demand with a duration of 3128 to 5944 hours per year;
- high-midload demand, representing demand with a duration of 782 to 3128 hours per year; and
- peakload demand, representing demand with a duration of less than 782 hours per year.

The model subtracts from the demand in each segment any generation coming from plants that must run – such as some CHP plants and desalination plants – and also generation from renewables. For generation from variable renewables, the amount of generation in each demand segment is estimated based on the historical correlation between generation and demand. The remainder of the demand in each segment must be met by production from dispatchable plants. The model determines the mix of dispatchable generation by constructing a merit order of the plants installed – the cumulative installed generation capacity arranged in order of their variable generation costs – and finding the point in the merit order that corresponds to the level of demand in each segment (Figure 16). As a result, plants with low variable generation costs – such as nuclear and lignite-burning plants in the Figure 16 example – will tend to operate for a high number of hours each year because even baseload demand is higher than their position in the merit order. On the other hand,

some plants with high variable costs, such as oil-fired plants, will operate only during the peak demand segment.

Figure 16: Example merit order and its intersection with demand in the power generation module



* Demand here means demand net of generation by “must run” plants such as desalination and some CHP plants, and net of generation by renewables.

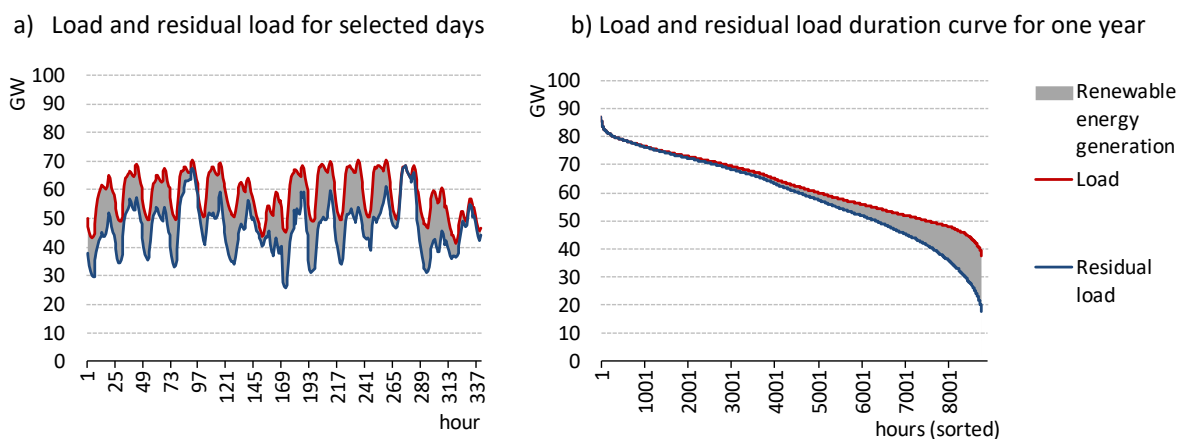
4.1.3 Calculation of the capacity credit and capacity factor of variable renewables

Power generation from weather-dependent renewables such as wind and solar power varies over time and the characteristics of the power supply from variable renewables have to be taken into account for the decisions on dispatch and capacity additions of the remaining, mostly dispatchable power plants. The effect of all variable renewables (solar PV, solar CSP without storage and wind on- and offshore) is taken into account via the capacity credit and the capacity factor in each load segment.

The capacity credit of variable renewables reflects the proportion of their installed capacity that can reliably be expected to be generating at the time of high demand in each segment. It determines by how much non-variable capacity is needed in each load segment. The capacity factor gives the amount of energy produced by variable renewables in each load segment and determines how much non-variable generation is needed in each segment.

Both, capacity credit and capacity factor are calculated based the comparison between the hourly load profile and the wind and solar supply time-series, derived from meteorological data. To quantify the effects of variable renewables, the hourly load profile is compare to the hourly residual load, being the electricity load after accounting for power generation from variable renewables (see Figure 17a). By sorting the residual load, the levels of average and maximal demand per load segment can be determined. The difference between the load levels of the normal load and the residual load gives the impact of variable renewables on the power generation and capacity needs (see Figure 17b).

Figure 17: Example electricity demand and residual load



The capacity factor of variable renewables (varRE) per load segment can be calculated generation per load segment s of the residual load.

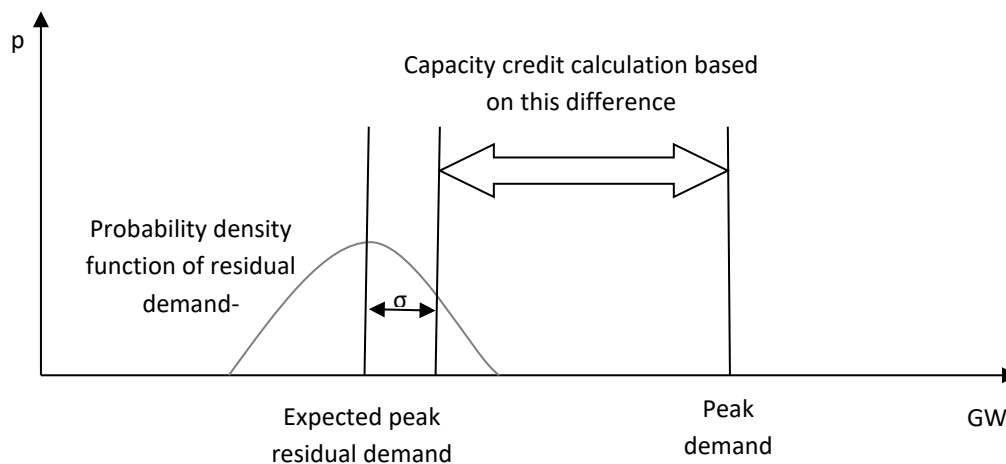
$$Capacity\ factor_s = \frac{Reduction\ Generation\ Needs_{non-var,s}}{Capacity_{varRE}} = \frac{Generation\ varRE_s}{Capacity_{varRE}}$$

For capacity additions, the peak load segment is relevant. The capacity credit is estimated based on the difference between maximal load and maximal residual load:

$$Capacity\ credit_{peak} = \frac{Reduction\ Capacity\ Needs_{non-var}}{Capacity_{varRE}} = \frac{\max_t(Load(t)) - \max_t(Residual\ Load(t))}{Capacity_{varRE}}$$

Meteorological data (wind speed and solar irradiation) for several years was used for the capacity credit calculation. In aggregating the results of capacity credit obtained from different years of meteorological data, as first order approach it was assumed that the annual peak residual demand is normally-distributed and calculated the capacity credit based on the difference between peak demand and the point one standard deviation above the residual peak demand (Figure 18).

Figure 18: Exemplary electricity demand and residual load



The meteorological data wind and solar data stems from the following re-analysis datasets

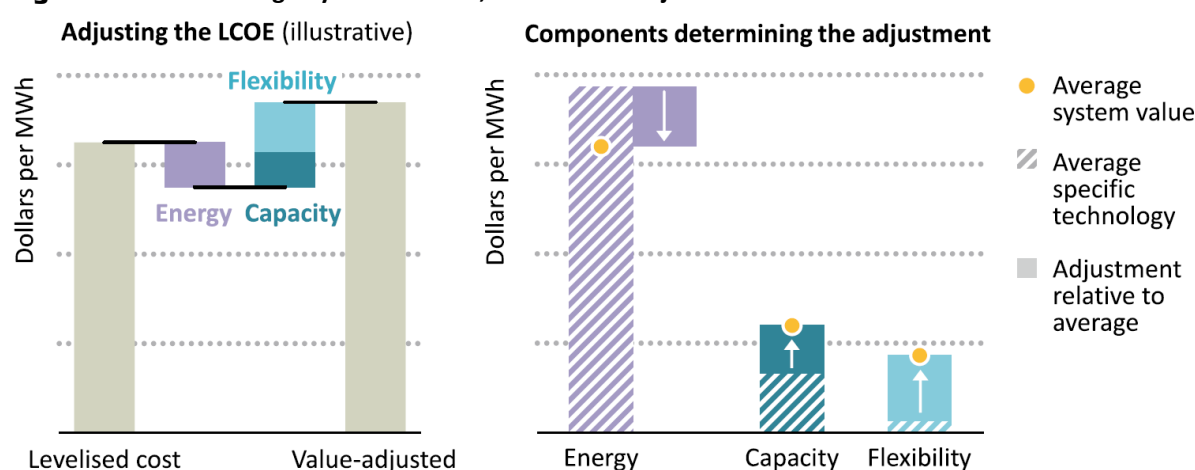
- World Wind Atlas (Sander + Partner GmbH): Global dataset of hourly wind speeds at 10 m height, 1979-2009, derived from reanalysis data based on climate modelling (Suraniana, 2010)
- Wind supply time-series for West and Eastern US as derived by WWITS (2010) and EWITS (2011).

- Wind and solar supply time-series for Europe-27 as provided by Siemens AG (Heide, 2010) for each major Region in Europe. Original meteorological wind speed stems from Reanalysis data (WEBROG, 2008).
- Hourly solar irradiation data from satellite observations for the US (NREL,2010)
- Estimation of solar irradiation based on solar height (Aboumahboub, 2009)

4.2 Value-adjusted Levelized Cost of Electricity

The value-adjusted LCOE (VALCOE) is a new metric for competitiveness for power generation technologies and was developed for the *WEO-2018*, building on the capabilities of the WEM hourly power supply model. It is intended to complement the LCOE, which only captures relevant information on costs and does not reflect the differing value propositions of technologies. While LCOE has the advantage of compressing all the direct technology costs into a single metric which is easy to understand, it nevertheless has significant shortcomings: it lacks representation of value or indirect costs to the system and it is particularly poor for comparing technologies that operate differently (e.g. variable renewables and dispatchable technologies). VALCOE enables comparisons that take account of both cost and value to be made between variable renewables and dispatchable thermal technologies.

Figure 19: Moving beyond the LCOE, to the value-adjusted LCOE



The VALCOE builds on the foundation of the average LCOE (or LRMC) by technology, adding three elements of value: energy, capacity and flexibility. For each technology, the estimated value elements are compared against the system average in order to calculate the adjustment (either up or down) to the LCOE. After adjustments are applied to all technologies, the VALCOE then provides a basis for evaluating competitiveness, with the technology that has the lowest number being the most competitive (Figure 19). The VALCOE is applicable in all systems, as energy, capacity and flexibility services are provided and necessary in all systems, even though they may not be remunerated individually. In this way, it takes the perspective of policy makers and planners. It does not necessarily represent the perspective of investors, who would consider only available revenue streams, which may also include subsidies and other support measures, such as special tax provisions, that are not included in the VALCOE.

The impact of the value adjustment varies by technology depending on operating patterns and system-specific conditions. Dispatchable technologies that operate only during peak times have high costs per MWh, but also relatively high value per MWh. For baseload technologies, value tends to be close to the system average and therefore they have a small value adjustment. For variable renewables, the value adjustment

depends mainly on the resource and production profile, the alignment with the shape of electricity demand and the share of variable renewables already in the system. Different operational patterns can be accounted for in the VALCOE, improving comparisons across dispatchable technologies.

The VALCOE is composed of LCOE and energy, capacity as well as flexibility value. Its calculation goes as follows:

$$VALCOE_x = LCOE_x + \overbrace{[\bar{E} - E_x]}^{\text{Energy value}} + \overbrace{[\bar{C} - C_x]}^{\text{Capacity value}} + \overbrace{[\bar{F} - F_x]}^{\text{Flexibility value}}$$

The adjustment for energy value $[E_x]$ of a technology x (or generation unit) is the difference between the individual unit to the system average unit $[\bar{E}]$. $[E_x]$ is calculated as follows:

$$\text{Energy value}_x \left(\frac{\$}{MWh} \right) = \frac{\sum_h^{8760} [WholesalePrice_h \left(\frac{\$}{MWh} \right) \times Output_{x,h} (MW)]}{\sum_h^{8760} Output_{x,h} (MW)}$$

Wholesale electricity prices and output volumes for each technology x in each hour h of the year are simulated. Wholesale prices are based on the marginal cost of generation only and do not include any scarcity pricing or other cost adders, such as operating reserves demand curves present in US markets. Hourly models are applied for the United States, European Union, China and India. For other regions, wholesale prices and output volumes are simulated for the four segments of the year presented in section 4.1.2.

The adjustment for capacity value $[C_x]$ of a generation unit is calculated as follows:

$$\text{Capacity value}_x \left(\frac{\$}{MWh} \right) = \frac{\text{Capacity credit}_x \times \text{Basis capacity value} (\$/kW)}{(\text{capacity factor}_x \times \text{hours in year}/1000)}$$

The Capacity credit reflects the contribution to system adequacy and it is differentiated for dispatchable versus renewable technologies:

- Dispatchable power plants = (1-unplanned outage rate by technology)
- Renewables = analysis of technology-specific values by region with hourly modelling

The Basis capacity value is determined based on simulation of capacity market, set by the highest “bid” for capacity payment. Positive bids reflect the payment needed to fill the gap between total generation costs (including capital recovery) and available revenue.

The Capacity factor is differentiated by technology:

- Dispatchable power plants = modelled as simulated operations in previous year
- Wind and solar PV = aligned with latest performance data from IRENA and other sources, improving over time due to technology improvements
- Hydropower and other renewables = aligned with latest performance data by region and long-term regional averages

The flexibility value $[F_x]$ of a generation unit is calculated as follows:

$$\text{Flexibility value}_x \left(\frac{\$}{MWh} \right) = \frac{\text{Flexibility value multiplier}_x \times \text{Base flexibility value} \left(\frac{\$}{kW} \right)}{(\text{capacity factor}_x \times \text{hours in year}/1000)}$$

- The Flexibility value multiplier by technology is based on available market data and held constant over time. Targeted changes in the operations of power plants to increase flexibility value are not represented.

- The Base flexibility value is a function of the annual share of variable renewables in generation, informed by available market data in the EU and US. The flexibility value is assumed to increase with rising VRE shares, up to a maximum equal to the full fixed capital recovery costs of a peaking plant.

4.2.1 Advantages and limitations of the VALCOE

VALCOE has several advantages over the LCOE alone:

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- It provides a more sophisticated metric of competitiveness incorporating technology-specific information and system-specific characteristics
- It reflects information/estimations of value provided to the system by each technology (energy, capacity/adequacy and flexibility)
- It provides a robust metric of competitiveness across technologies with different operational characteristics (e.g. baseload to peaking, or dispatchable to variable)
- It provides a robust metric of competitiveness with rising shares of wind and solar PV

However, network integration costs are not included, nor are environmental externalities unless explicitly priced in the markets. Fuel diversity concerns, a critical element of electricity security, are also not reflected in the VALCOE.

The VALCOE approach has some parallels elsewhere, in other approaches used for long-term energy analysis, as well some real-world applications. Optimisation models implicitly represent the cost and value of technologies, but may be limited by the scope of costs included, such as those related to ancillary services. Other long-term energy modelling frameworks, such as the NEMS model used by the US Department of Energy, have incorporated cost and value in capacity expansion decisions. In policy applications, in the auction schemes in Mexico, average energy values for prospective projects have been simulated and used to adjust the bid prices, seeking to identify the most cost-effective projects.

4.3 Electricity transmission and distribution networks

The model calculates investment in transmission and distribution networks. Transmission networks transport large volumes of electricity over long distances at high voltage. Most large generators and some large-scale industrial users of electricity are connected directly to transmission networks. Distribution networks transform high-voltage electricity from the transmission network into lower voltages, for use by light-industrial, commercial, and domestic end-users.

Investment in grid infrastructure are driven by three factors: investment in new grid infrastructure to accommodate growing demand, investment to replace or refurbish assets that reach the end of their operational lifetime and investments required to integrate renewables in the power sector.

4.3.1 Investment due to new growth

New investment due to growth in electricity demand is assumed to scale with increase in electricity demand. This calculation is performed for distribution and transmission networks separately and for each region, as the increase in line length per region depends on a number of region-specific factors (e.g. population density).

The investment per type (transmission and distribution) is calculated as follows:

$$Investment^{new} = (\beta \cdot Increase\ in\ power\ generation) \cdot Line\ costs$$

The term β , which reflects the additional amount of network length needed for each additional unit of generation, is estimated for each region using data on network length and generation for the period 1970-

2014⁸. The unit costs of addition transmission or distribution lines are derived from observed capital expenditure data. For future years we assume that the real unit cost of networks increases as labour costs increase, taking into account the differences in labour costs between countries.

4.3.2 Investment due to ageing infrastructure

Assuming an average lifetime of 40 years, the amount of grid infrastructure in need for refurbishment is determined and the corresponding investment is calculated Page | 44

$$\text{Investment}^{age} = \text{Line length reaching 40 years} * (\text{Line costs} * \text{reduction factor})$$

Because building new assets entails additional costs to those entailed in refurbishing them, a region-specific cost reduction factor is introduced.

4.3.3 Additional investment due to renewables

A considerable amount of the capacity additions projected over the WEO period is from renewables. The geographical location of these technologies is often strongly influenced by the location of the underlying resource (e.g. areas where the wind is strong or insolation is high), which may not be close to existing centres of demand. In addition, some of these technologies, mainly solar PV, are connected at the end-user side of the grid infrastructure. This modular deployment of generation capacity can lead to increase distribution capacity needs.

Because the introduction of large quantities of remote or variable renewables was not a marked feature of the historic development of electricity networks (with the exception of regions where remote hydroelectricity represents a large proportion of the generation mix), the addition of more renewables is likely to increase the average length of network additions and the cost of transmission and distribution per unit of energy.

Additional transmission network costs are derived based on specific renewable grid integration costs, derived from a literature review. For example for wind, the typically range between \$100 and \$250 per kW of installed wind capacity. Regional differences due to geography and labour costs are taken into account.

The estimation of costs of distribution grid extensions for renewables contains a lot more uncertainties than the transmission grid costs, as less data or studies are available on the technically complex distribution network is available and own use of distributed generation can in turn lead to a reduced need for distribution grid infrastructure. Therefore, we assume, that additional network investment is required only if the electricity generated from distributed generation, such as solar PV in buildings and bioenergy in industry, exceeds local demand and is fed back to the system.

4.4 Hourly model

To quantify the scale of the challenge arising from the integration of high shares of VRE and to assess which measures could be used to minimise curtailment, a new hourly model has been developed for *WEO-2016*, to provide further insights into the operations of power systems. The model builds upon the annual projections generated in the WEM and makes it possible to explore emerging issues in power systems, such as those that arise as the share of VRE continues to rise. The model then feeds the main WEM model with information about additional constraints on the operations of different power plants. The model is a classical hourly dispatch model, representing all hours in the year, setting the objective of meeting electricity demand in each

⁸The data on historic network size and capital expenditure stems from ABS Energy Research (2010), Global Transmission & Distribution Report Ed. 9-2010, and NRG Expert (2013), Electricity Transmission and Distribution Report and Database Edition 3, 2012-2017.

hour of the day for each day of the year at the lowest possible cost, while respecting operational constraints.⁹ All 106 power plant types recorded in the WEM and their installed capacities are represented in the hourly model, including existing and new fossil-fuelled power plants, nuclear plants and 16 different renewable energy technologies. The fleet of power plants that is available in each year is determined in WEM and differs by scenario, depending on the prevalent policy framework. These plants are then made available to the hourly model and are dispatched (or chosen to operate) on the basis of the short-run marginal operating costs of each plant (which are mainly determined by fuel costs as projected in WEM) to the extent required to meet demand. The dispatch operates under constraints: there are minimum generation levels to ensure the flexibility and stability of the power system and to meet other needs (such as combined heat and power); the variability of renewable resources (such as wind and solar) determines the availability of variable renewables and, hence, the maximum output at any point in time; and ramping constraints apply, derived from the level of output in the preceding hour and the characteristics of different types of power plants. The hourly dispatch model does not represent the transmission and distribution system, nor grid bottlenecks, cross-border flows or the flow of power through the grid. It therefore simulates systems that are able to achieve full integration across balancing areas in each WEM region (e.g. United States, European Union, China and India).

Key inputs to the model include detailed aggregate hourly production profiles for wind power and solar PV for each region, which were generated for the WEO by combining simulated production profiles for hundreds of individual wind parks and solar PV installations, distributed across the relevant region¹⁰ The individual sites were chosen to represent a broad distribution within a region, allowing the model to represent the smoothing effect achieved by expanding balancing areas. On the demand side, the model uses a detailed analysis, with hourly demand profiles for each specific end-use (such as for lighting or water heating in the residential sector), coupled with the annual evolution of electricity demand by specific end-use over the *Outlook* period from the main WEM model (see Section 3.4).

The hourly model accounts for grid, flexible generation and system-friendly development of VRE, in three steps: first, it assesses the amount of curtailment of variable renewables that would occur without demand-side response and storage. Second, it deploys demand-side response measures, based on the available potential in each hour for each electricity end-use. And third, it uses existing and new storage facilities to determine the economic operations of storage based on the price differential across hours and charge/discharge periods. It thereby enables the integration needs arising from growing shares of renewables to be assessed.

Among the other important model outputs is the resulting hourly market price, which can drop to zero in the hours when generation from zero marginal cost generators (such as variable renewables) is sufficient to meet demand. By multiplying the market price by generation output in each hour, the model calculates the revenues received for the output in each hour by each type of plant, creating a basis for calculating the value of VRE. Naturally, the model also includes hourly operation information for each plant type, including fuel costs and associated greenhouse-gas and pollutant emissions.

4.5 Mini- and off-grid power systems

In support of the Africa Energy Outlook in 2014, the representation of mini- and off-grid systems, related to those gaining access to electricity, was improved and better integrated into the WEM. In line with the approach for on-grid power systems, to meet additional electricity demand, the model chooses between available technologies for mini- and off-grid systems based on their regional long-run marginal costs.

⁹ The model works on an hourly granularity, and therefore all intra-hour values of different devices (e.g. of storage technologies) are not captured.

¹⁰ Wind and solar PV data are from Renewables.ninja (<https://beta.renewables.ninja/>) and Ueckerdt, F., et. al. (2016).

Technology costs for small remote systems were reviewed and updated for the report. The technologies are restricted by the available resources in each region, including renewable energy resources such as river systems, biomass feedstocks (e.g. forests and agricultural residues), wind and the strength of solar insolation. Back-up power generation for those with access to the grid, typically gasoline or diesel fuelled, was also represented to the model, with its projected use tied to the quality of the on-grid power supply.

4.6 Renewables, combined heat and power and distributed generation modules

The projections for renewable electricity generation, combined heat and power (CHP), and distributed generation (DG) are derived in separate sub-modules. The future deployment of these technologies and the investment needed for such deployment were assessed on the basis of potentials in each country/region.

4.6.1 Combined heat and power and distributed generation

The CHP option is considered for fossil fuel and bioenergy-based power plants. The CHP sub-module uses the potential for heat production in industry and buildings together with heat demand projections, which are estimated econometrically in the demand modules. The distributed generation sub-module is based on assumptions about market penetration of DG technologies.

4.6.2 Renewable energy

The projections of renewable electricity generation are derived in the renewables sub-module, which projects the future deployment of renewable sources for electricity generation and the investment needed. The deployment of renewables is based on an assessment of the potential and costs for each source (bioenergy, hydropower, photovoltaics, concentrating solar power, geothermal electricity, wind, and marine) in each of the 25 WEM regions.¹¹ By including financial incentives for the use of renewables and non-financial barriers in each market, as well as technical and social constraints, the model calculates deployment as well as the resulting investment needs on a yearly basis for each renewable source in each region. The methodology is illustrated in Figure 20.¹²

The model uses dynamic cost-resource curves¹³. The approach consists of two parts:

- 1) For each renewable source within each region, static cost-resource curves¹⁴ are developed. For new plants, we determine long-term marginal generation costs. Realisable long-term potentials (see Box 2) have been assessed for each type of renewable in each region.
- 2) Next, the model develops for each year a dynamic assessment of the previously described static cost-resource curves, consisting of:

¹¹ A number of sub-types of these technologies are modelled individually, as follows. Biomass: small CHP, medium CHP, electricity only power plants, biogas-fired, waste-to-energy fired and co-fired plants. Hydro: large (≥ 10 MW) and small (< 10 MW). Wind: onshore and offshore. Solar photovoltaics: large-scale and buildings. Geothermal: electricity only and CHP. Marine: tidal and wave technologies.

¹² For a detailed description of the approach used in this model – which was originally developed by Energy Economics Group (EEG) at Vienna University of Technology in cooperation with Wiener Zentrum für Energie, Umwelt und Klima – see Resch et.al. (2004).

¹³ The concept of dynamic cost-resource curves in the field of energy policy modelling was originally devised for the research project Green-X, a joint European research project funded by the European Union's fifth Research and Technological Development Framework Programme – for details see www.green-x.at.

¹⁴ Renewable energy sources are characterised by limited resources. Costs rise with increased utilisation, as in the case of wind power. One tool to describe both costs and potentials is the (static) cost-resource curve. It describes the relationship between (categories of) available potentials (wind energy, biomass, and hydropower) and the corresponding (full) costs of utilisation of this potential at a given point-of-time.

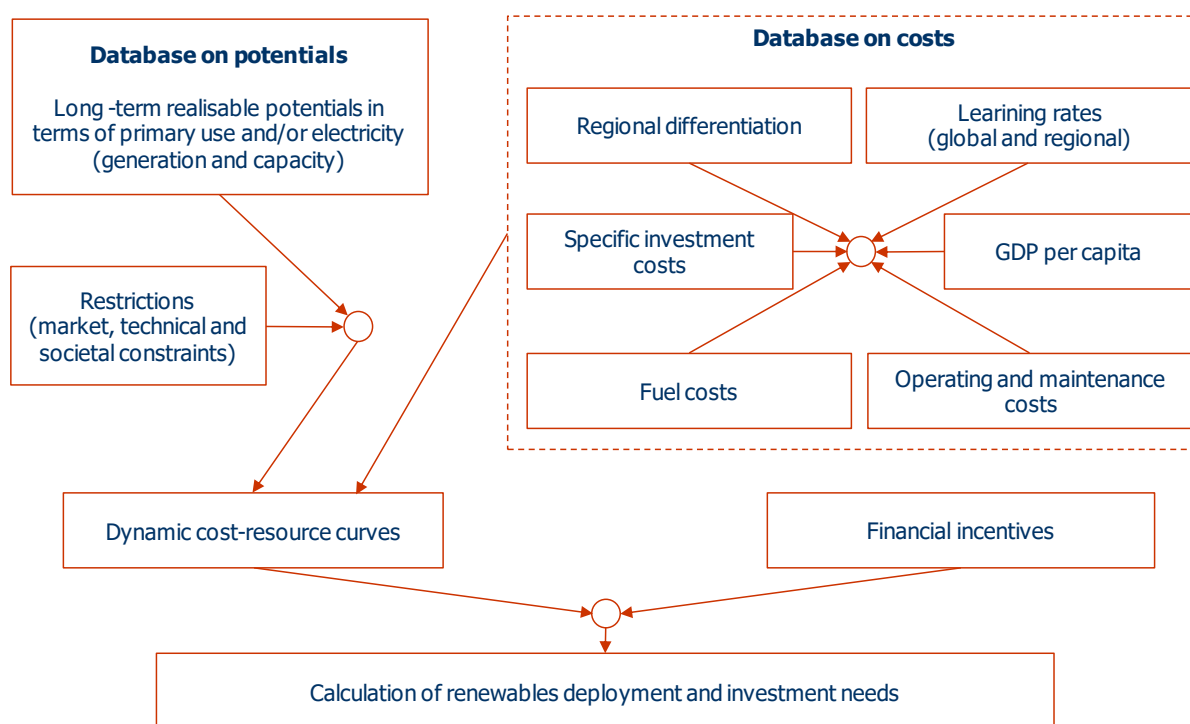
Dynamic cost assessment: The dynamic adaptation of costs (in particular the investment and the operation and maintenance components) is based on the approach known as “technological learning”. Learning rates are assumed by decade for specific technologies.

Dynamic restrictions: To derive realisable potentials for each year of the simulation, dynamic restrictions are applied to the predefined overall long-term potentials. Default figures are derived from an assessment of the historical development of renewables and the barriers they must overcome, which include:

- Market constraints: The penetration of renewables follows an S-curve pattern, which is typical of any new commodity.¹⁵ Within the model, a polynomial function has been chosen to describe this impact – representing the market and administrative constraints by region.
- Technical barriers: Grid constraints are implemented as annual restrictions which limit the penetration to a certain percentage of the overall realisable potential.

By defining financial incentives for the use of renewables and non-financial barriers in each market, as well as technical and societal constraints, the model calculates deployment as well as the resulting investment needs on a yearly base for each renewable source in each region.

Figure 20: Approach used for the renewables module



¹⁵ An S-curve shows relatively modest growth in the early stage of deployment, as the costs of technologies are gradually reduced. As this is achieved, there will be accelerating deployment. This will finally be followed by a slowing-down, corresponding to near saturation of the market.

Box 2: Long-term potential of renewables

The starting point for deriving future deployment of renewables is the assessment of long-term realisable potentials for each type of renewable and for each world region. The assessment is based on a review of the existing literature and on the refinement of available data. It includes the following steps:

1. The *theoretical* potentials for each region are derived. General physical parameters are taken into account to determine the theoretical upper limit of what can be produced from a particular energy, based on current scientific knowledge.
2. The *technical* potential can be derived from an observation of such boundary conditions as the efficiency of conversion technologies and the available land area to install wind turbines. For most resources, technical potential is a changing factor. With increased research and development, conversion technologies might be improved and the technical potential increased.

Long-term *realisable* potential is the fraction of the overall technical potential that can be actually realised in the long term. To estimate it, overall constraints like technical feasibility, social acceptance, planning requirements and industrial growth are taken into consideration.

5 Oil refining and trade

The refinery and trade module links oil supply and demand. It is a simulation model, with capacity development and utilisation modelled for 134 individual countries, with the remaining countries grouped into 11 regions. This module has several auxiliaries that stretch into supply and demand domains to better link both:

- Natural gas liquids module to determine yields of various products as well as condensate.
- Extra-heavy oil and bitumen module to model synthetic crude oil output and diluent requirements for bitumen.
- Split of oil demand into different production categories for all sectors except road transport and aviation. The latter are provided by WEM's transport demand model.

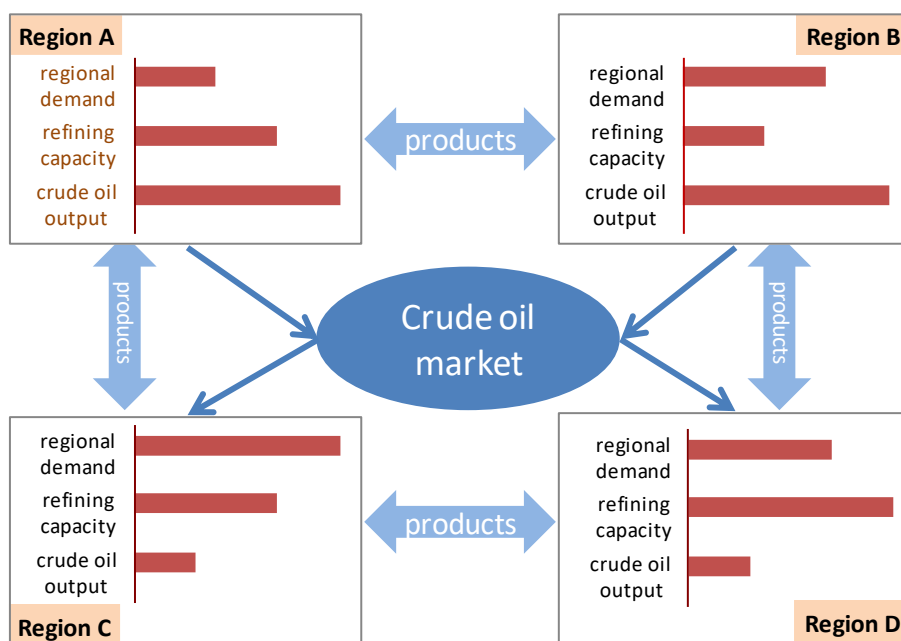
Crude distillation (CDU) capacity is based on 2017 data from the IEA. Capacity expansion projects that are currently announced are assessed individually to identify only the projects that are very likely to go ahead. Some of these are delayed from their announced start-up dates to allow for a more realistic timeline. The model also takes into account refinery closures that have been announced. Beyond 2023, new capacity expansion is projected based on crude availability and product demand prospects for each of the regions specified below.

Projections for refining sector activity are based primarily on CDU capacity and utilisation rates. Secondary unit capacities (such as fluid catalytic cracking, hydrocracking) and run rates, are defined by the required output mix to match product demand. Among oil-importing regions, priority call on international supply of crude oil is given to those where demand is growing: robust domestic demand is effectively a proxy for refinery margins that are not explicitly calculated or used by the model.

Oil output and demand projections are provided by WEM's fossil-fuel supply and final energy consumption modules. Refineries do not provide for 100% of oil product demand. For the purposes of this analysis, we show the net call on refineries after the removal of biofuels, liquefied petroleum gas (LPG), ethane and light naphtha from natural gas liquids (NGL), synthetic liquids from coal-to-liquids (CTL) and gas-to-liquids (GTL) and additives.

The supply-side nomenclature for the refining model is slightly different from the oil supply model. The term "crude oil" used in the model describes all crude oils that have conventional-type quality for processing purposes. This includes conventional crude oil from the supply model, some extra heavy oils that are not diluted or upgraded, tight oil and synthetic crude from bitumen upgrading processes. Diluted bitumen and condensate are represented as separate streams for intake and trade modelling purposes.

Yields, output and trade are defined for the following product categories: LPG, naphtha, gasoline, kerosene, diesel, heavy fuel oil and other products (which include petroleum coke, refinery gas, asphalt, solvents, wax, etc). Refinery feedstock trading across the regions is only considered for the residual fuel oil category. Vacuum gas oil is added to the middle distillates pool for trade flow purposes. Crude oil trade position is analysed for each individually modelled country or region, but refined products balances follow WEO's demand model granularity of 25 individual countries or regions (Figure 21).

Figure 21: Schematic of refining and international trade module

For the purposes of the trade analysis we have grouped countries into a number of regions that reflect established oil market and trading areas. Thus, for this analysis, Europe comprises both OECD and non-OECD Europe, and North America includes the United States, Mexico and Canada. Africa is divided into North Africa, West Africa and East Africa. The latter includes South Africa and all the countries in the east of the continent that are supplied from the Indian Ocean. West Africa includes central African landlocked countries and those having access to the Atlantic Ocean. Asia includes all OECD and non-OECD countries in the region, with the exception of the five Central Asian states that, together with the Caucasus, make up the Caspian region. We use the term “Other Asia” alongside China and India as a way to group the rest of the region, including OECD Asia Pacific. Russia and Brazil are modeled as individual countries.

6 Energy supply

6.1 Oil

The purpose of this module is to project the level of oil production in each country through a partial bottom-up approach¹⁶ building on:

- the historical series of production by countries;
- standard production profiles and estimates of decline rates at field and country levels derived from the detailed field-by-field analysis undertaken in *WEO-2008* and updated in *WEO-2013*;
- an extensive survey of upstream projects sanctioned, planned and announced over the short term in both OPEC and Non-OPEC countries, including conventional and non-conventional reserves, as performed by the IEA Oil Market Report team; this is used to drive production in the first 5 years of the projection period (a summary of the differences in methodology between WEO and the Medium-Term Oil Market Report is included as Box 3);
- a methodology, which aims to replicate as much as possible the decision mode of the industry in developing new reserves by using the criteria of net present value of future cash flows;

¹⁶ “Bottom-up” in this context means “based on field-by-field analysis”.

- a set of economic assumptions discussed with and validated by the industry including the discount rate used in the economic analysis of potential projects, finding and development costs, and lifting costs;
- an extensive survey of fiscal regimes translating into an estimate of each government's take in the cash flows generated by projects; and
- values of remaining technically recoverable resources (Table 6) calculated based on information from the United States Geological Survey (USGS), BGR and other sources.

The paragraphs below describe how the USGS data are used in the WEM. USGS published in 2000 its World Petroleum Assessment, a thorough review of worldwide conventional oil (and gas) resources. In it, USGS divided the resources into three parts:

- Known oil, which contains both cumulative production and reserves in known reservoirs.
- Undiscovered oil, a basin-by-basin estimate of how much more oil there may be to be found, based on knowledge of petroleum geology.
- Reserves growth, an estimate of how much oil may be produced from known reservoirs on top of the known reserves. As the name indicates, this is based on the observation that estimates of reserves (including cumulative production) in known reservoirs tend to grow with time as knowledge of the reservoir and technology improves. For the 2000 assessment, reserve growth as a function of time after discovery was calibrated from observation in US fields, and this calibration applied to the known worldwide reserves to obtain an estimate of worldwide reserves growth potential.

Since the 2000 assessment, USGS has regularly published updates on undiscovered oil in various basins, and these were considered in the WEM. In 2012, USGS published an updated summary of worldwide undiscovered oil, as well as a revised estimate for reserves growth based on a new field-by-field method focused on the large fields in the world. Previously the known oil estimates used by the USGS when generating its reserve growth estimates had not been released publicly. However, a recent report provides its assumptions, albeit aggregated at a global level (USGS, 2015). The USGS estimate of cumulative production and reserves outside the United States is 2 060 billion barrels, which is in close alignment with the IEA equivalent estimate of 2 050 billion barrels. For conventional oil, the USGS estimates of undiscovered oil and reserves growth published in 2012 provide the key foundation for the values used in WEM. The WEM estimates of remaining technically recoverable resources combine USGS undiscovered, USGS reserves growth and IEA estimates for known. A similar analysis, based on the same USGS publications, feeds into the IEA NGLs and natural gas resources database, which allows looking at total conventional liquid hydrocarbons resources and conventional gas resources.

Table 6: Remaining technically recoverable oil resources by type and region, end-2017 (bbl)

Oil (billion barrels)	Proven reserves	Resources	Conventional crude oil	Tight oil	NGLs	EHOB	Kerogen oil
North America	228	2 315	246	128	138	804	1 000
Central and South America	321	845	238	60	50	494	3
Europe	14	117	61	19	29	3	6
Africa	127	454	311	54	86	2	-
Middle East	808	1 145	921	29	151	14	30
Eurasia	144	961	246	85	60	552	18
Asia Pacific	52	290	131	72	68	3	16
World	1 694	6 127	2 155	446	582	1 872	1 073

Notes: EHOB = extra-heavy oil and bitumen. Tight oil includes tight crude oil and condensate volumes except for the United States, which includes tight crude oil only (US tight condensate volumes are included in natural gas liquids).

Source: IEA (2018b).

Box 3: WEO differences in methodology compared with the Medium-Term Oil Market Report

The IEA publishes annually projections of oil supply and demand for the next five years in the Medium Term Oil Market Report (MTOMR), and for the next two and half decades in the WEO. Those two sets of projections use different methodologies that evolve every year. This makes comparisons not straightforward for some readers. This box summarizes the key differences.

A very important difference between MTOMR and WEO is the oil price assumption. MTOMR assumes that the oil price follows the futures market curve at the time of publication; this is then used for the demand projection, and supply is assumed to follow, with OPEC filling the gap between field-by-field projections of non-OPEC supply and demand. WEO determines the equilibrium price that brings supply and demand in balance. However, to avoid generating investment/price cycles which would obscure policy effects and long term trends, this equilibrium is performed as a trend and not year-by-year.

WEO relies on the field-by-field analysis of MTOMR to guide production by country in the first five years of the projection period. The country by country methodology is also extended to OPEC countries, so OPEC is not treated as the swing producer, though constraints thought to represent possible OPEC policies are incorporated in the WEM oil supply module.

Results are also often presented slightly differently in the two reports. Conventional and unconventional oil may be grouped differently with WEO including all of Canadian oil sands and Venezuelan Orinoco production in unconventional, while MTOMR generally counts only upgraded bitumen or extra-heavy oil as unconventional.

In analysing and projecting oil demand, WEO and MTOMR have methodological differences. Since WEO is concerned with projections of supply and demand of all energy sources and projects a world energy balance in the future, it incorporates all demand components. Due to the nature of these components, they can be with a plus or a minus sign (i.e. increasing or decreasing the demand figure). Therefore, while WEO incorporates statistical differences and refinery transformation losses into historical demand values and projects those into the future, MTOMR's demand definition does not include these two categories in its historical values and projections.

WEO also splits biofuels from historical oil demand and projects oil demand and biofuels demand separately. OMR does not separate biofuels from the historical oil demand, and the oil demand is projected with a mix of biofuels. As a result, one barrel of oil from MTOMR projections has lower energy content than that of WEO if biofuels are projected to grow. A direct comparison of WEO and OMR results is thus only possible if biofuels are stripped off MTOMR values of oil demand.

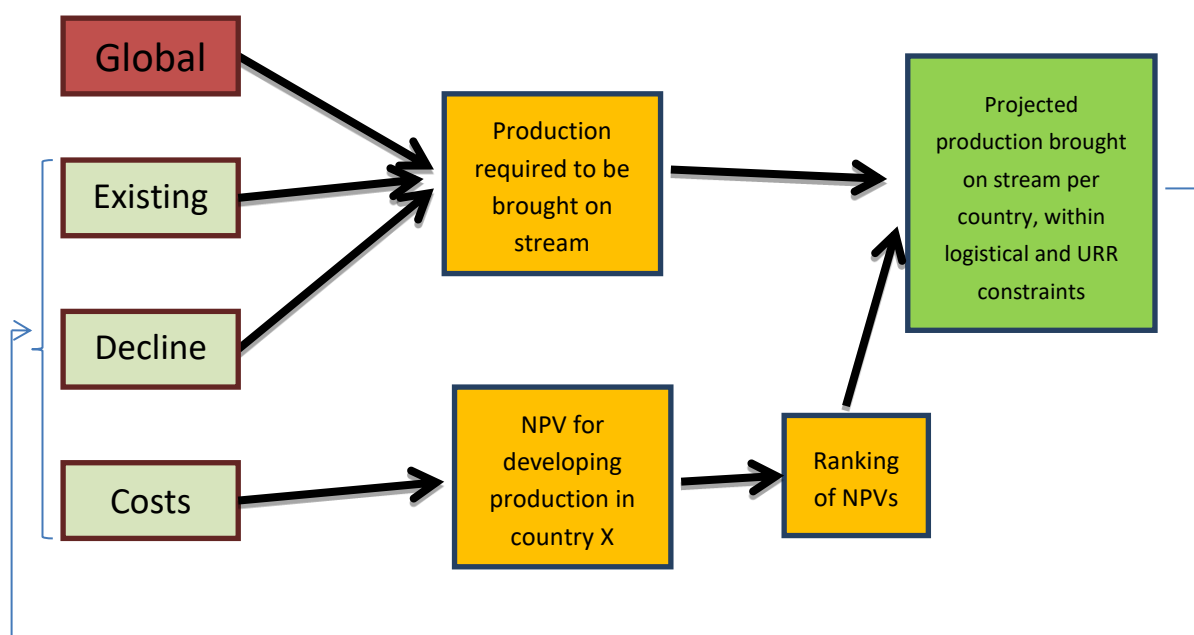
The differences in refining mainly concern the interpretation of installed capacity. WEO discounts most of idled capacity of Chinese teapot and smaller refineries that run below 30% utilization rates. It also discards the mothballed capacity in entirety, even if the owner of the refinery has announced that it is a temporary economic shutdown. MTOMR and WEO may also differ in their projection of firm capacity additions within the same timeframe.

Each country's projected oil production profile is made of six components. Conventional fields also distinguished by water depth (onshore, shallow offshore [water depth less than 400 metres], deepwater fields [between 400-2 000 metres] and ultra-deepwater fields [greater than 2 000 metres]). For unconventional oil, extra-heavy oil and bitumen is also distinguished by mining or *in situ* technologies and tight oil by play productivity.

- Production from currently producing fields as of end-2014: the projected decline rates in each country are derived from the analysis summarised in Box 4;
- Production from discovered fields with sanctioned, planned and announced developments;
- Production from discovered fields awaiting development;
- Production from fields yet to be discovered;
- Production of Natural Gas Liquids; and
- Production of unconventional oil.

Trends in oil production are modelled using a bottom-up methodology, making extensive use of our database of worldwide ultimately technically recoverable resources. The methodology aims to replicate investment decisions in the oil industry by analysing the profitability of developing reserves at the project level (Figure 22).

Figure 22: Structure of the oil supply module



In the WEM oil supply module, production in each country or group of countries is separately derived, according to the type of asset in which investments are made: existing fields, new fields and non-conventional projects. Standard production profiles are applied to derive the production trend for existing fields and for those new fields (by country and type of field) which are brought into production over the projection period.

The profitability of each type of project is based on assumptions about the capital and operating costs of different types of projects, and the discount rate, representing the cost of capital. The net present value of the cash flows of each type of project is derived from a standard production profile. Projects are prioritised by their net present value and the most potentially profitable projects are developed. Constraints on how fast projects can be developed and how fast production can grow in a given country are also applied. These are derived from historical data and industry inputs. When demand cannot be met without relaxing the constraints, this signals that oil prices need to be increased.

6.1.1 US tight oil model

A new module was developed for *WEO-2016* in order to explore the sensitivity of production of tight oil in the United States to changes in price and resource availability. The module projects possible future production

across 23 shale plays taking into account the estimated ultimate recovery (EUR), initial production, rate of decline and drilling costs of wells drilled and completed across different areas of each play. Existing production is modelled by estimating decline parameters of wells based on latest production information available, and the time when these wells were completed.

Price dynamics affect the number of rigs that are available to drill new wells, with a lag between increases in prices and increases in the number of rigs operating (as observed empirically). Technology increases both the speed at which new wells can be drilled and completed (the number of wells per rig) and the amount of production from each well (the EUR/well). Conversely, the EUR/well of a given area in a given play is assumed to degrade as that area is depleted over time.

Rigs are distributed across plays based on current activity, and the expected cost effectiveness of new wells that are drilled. It is assumed that while operators would aim to drill only in their most productive areas, some wells will inevitably be located in regions with lower EUR/well or higher decline rates. The product of numbers rigs, wells/rig, and production/well then gives the new production that comes online in each play in each month starting in January 2016. Results from this module are directly fed into WEM for each of the scenarios implemented.

A similar model was developed for shale gas production in the United States

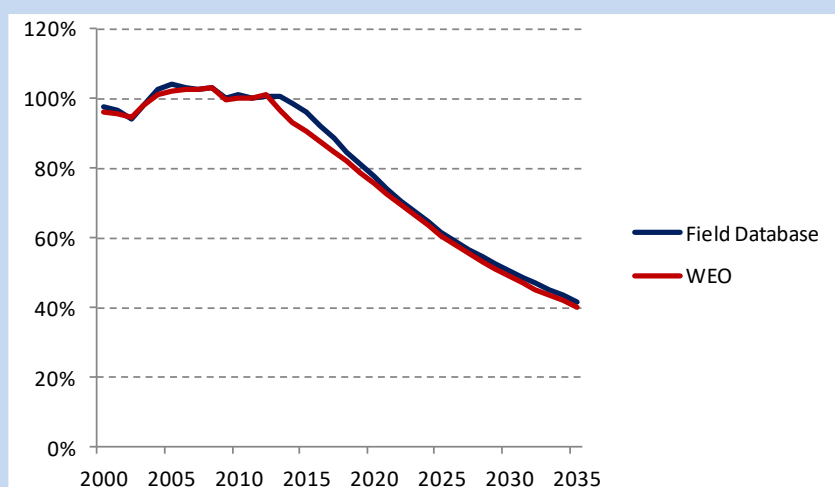
Box 4: Methodology to account for production decline in oil and gas fields

WEO-2008 and *WEO-2013* presented analyses of decline rates in oil fields based on looking at actual production data time series for a large number of fields. The outcome of this work is a value for observed decline rates by type of field, geographical location and phase of decline, as well as an estimate for the difference between observed decline rates and natural decline rates (the decline rate that would be observed in the absence of further investment in producing fields).

In principle this provides the elements to project the future production of all fields in decline among the set of fields used. The methodology could be as follows:

- For each field in the database, assign a type (super-giant, giant... onshore, offshore, deepwater) and determine the current decline phase.
- Project future production for each field as per corresponding decline rate provided in *WEO-2013*, updating decline rates as the field changes phase.

But this does not allow the projection of world production from all currently producing fields, as one also needs to project production from fields currently ramping up (*i.e.* one needs to know their future peak year and peak production) and from declining fields not in the database. This is done using a proprietary commercial database that contains a representation of possible future production for all fields in the world. Based on this more complete data set, the WEM oil supply module uses a country-by-country parameterisation of natural decline rates (for each resources type) and a production profile for resources developed in each country during the projection period (*i.e.* resources developed in a given year then provide a ramping-up of production, followed by peak and decline). As shown in Figure 23, this parameterization gives a good match with the results of the proprietary database (as the two databases have slightly different base productions, both are normalized to allow a clearer comparison of decline) for the long term decline; in the short term, the IEA field-by-field analysis (coming from the Medium Term Oil Market Report) is more conservative than the commercial database, as it accounts for expected field maintenance and weather disruptions.

Figure 23: Evolution of production of currently producing conventional oil fields from a field-by-field database and from the WEM

Source: Rystad Energy AS, IEA analysis and databases.

6.2 Natural gas

Gas production and trade projections are derived from a hybrid WEM gas supply module involving bottom-up and top-down approaches. The module has similar inputs, logic and functionality as the oil supply module described above. However, contrary to oil which is assumed to be freely traded globally, gas is assumed to be primarily regionally traded, with inter-regional trade constrained by existing or planned pipelines, LNG plants and long-term contracts. So the module is first run for 17 regions (see Annex 1), for which indigenous production is modelled on the basis of remaining technically recoverable resources (Table 7) and depletion rates, taking account of production costs and prices in the region. Subtracting domestic production from demand, in aggregate for each importing regional block, yields gas import requirements. For each gas net-exporting regional block, aggregate production is determined by the level of domestic demand and the call on that region's exportable production (which is determined by the import needs of the net importing regions and supply costs). Long term contracts (current, or assumed for the future) are served first, then exporting regions compete on the basis of marginal production costs plus transport costs, within the current and assumed future LNG and pipeline capacities. This provides an inter-block gas trade matrix. The effects of pricing policies (current or assumed for the future) of exporting regions can also be taken into account.

Table 7: Remaining technically recoverable natural gas resources, end-2017 (tcm)

Natural gas (trillion cubic metres)	Proven reserves	Resources	Conventional gas	Tight gas	Shale gas	Coalbed methane
North America	12	134	50	11	66	7
Central and South America	9	84	28	15	41	-
Europe	6	47	19	5	18	5
Africa	18	101	51	10	40	0
Middle East	81	122	103	9	11	-
Eurasia	76	171	134	10	10	17
Asia Pacific	20	139	45	21	53	21
World	221	798	429	81	239	50

Source: IEA (2018b).

Production within each region is allocated to individual countries according to remaining technically recoverable resources, depletion rates and relative supply costs, with a logic similar to that of the oil supply

module, but with “demand” being provided by the respective regional production derived in the previous step.

6.2.1 Gas infrastructure model

For this year’s edition of the WEO, we developed a European gas infrastructure model, allowing us to examine trade flows and potential bottlenecks on a disaggregated country-by-country basis. The modelled countries include the EU-28, plus Switzerland and countries of southeast Europe that are contracting parties to the Energy Community Treaty: Albania, Bosnia and Herzegovina, the former Yugoslav Republic of Macedonia, Kosovo, Moldova, Montenegro, Serbia and Ukraine. Georgia is not included in this analysis, although part of the Energy Community, it is not contiguous with the single market; Turkey and Belarus, Iceland and Norway are the only countries in our “Europe” aggregate that are not included.

The model takes in the following inputs at a country level: monthly gas production, consumption; pipeline, storage and LNG capacity. To ensure consistency with the World Energy Model’s other gas supply modules, the European Union’s gas production, import volumes and consumption are drawn from the New Policies Scenario and are fixed inputs into the model. However, we disaggregated production and demand into monthly values, constructing individual peak gas load outlooks for all EU countries, using the results of our hourly power sector model (see section 4) as well as detailed analysis of the outlook for the buildings sector. Existing transmission pipeline capacities (and bidirectionality, where applicable) were taken from the European Network of Transmission System Operators for Gas’ Ten Year Network Development Plan (ENTSO-G, 2017 and 2018). Storage and LNG capacities, both existing and future, were taken from Gas Infrastructure Europe (GIE). For future transmission projects, we assessed infrastructure development from a bottom-up, project-by-project perspective, differentiating advanced (e.g. those with FID or strong political backing) and less advanced projects. Some Projects of Common Interest (PCI), particularly those competing with one another, are assumed not to go ahead in the analysis. Others had their commissioning dates adjusted to better reflect current market and political conditions. Key variables in the model include pipeline and LNG capacities assumed to be booked under long-term take-or-pay import contracts, taken from a Cedigaz database (2018); storage and transmission tariff rates (taken from publically available sources as well as the Agency for the Cooperation of Energy Regulators (ACER) Market Monitoring Report); and assumed capacity availabilities for spot trading of pipeline, storage and LNG gas.

The model is built using GAMS software, following a nodal structure, calculating per-country aggregates for storage, production, and transmission capacity with neighbouring countries. It then applies a mass balance function to the single European gas market, optimising flows subject to the modelled constraints, returning monthly equilibrium flows between all modelled countries, showing pipeline utilisation and storage withdrawal rates as well as congestion levels where insufficient capacity exists to satisfy demand.

6.3 Coal

The coal module is a combination of a resources approach (Table 8) and an assessment of the development of domestic and international markets, based on the international coal price. Production, imports and exports are based on coal demand projections and historical data, on a country basis. Four markets are considered: coking coal, steam coal, lignite and peat. World coal trade, principally constituted of coking coal and steam coal, is separately modelled for the two markets and balanced on an annual basis.

Table 8: Remaining technically recoverable coal resources, end-2017 (billion tonnes)

Coal (billion tonnes)	Proven reserves	Resources	Coking coal	Steam coal	Lignite
North America	259	8 389	1 032	5 838	1 519
Central and South America	14	61	3	32	25
Europe	135	977	188	387	402
Africa	13	297	35	261	0
Middle East	1	41	19	23	-
Eurasia	189	4 301	731	2 190	1 380
Asia Pacific	423	8 941	1 505	6 022	1 414
World	1 034	23 007	3 513	14 754	4 740

* The breakdown of coal resources by type is an IEA estimate and proven reserves are a subset of resources. ** The reserves to production ratio (R/P) represents the length of time that proven reserves would last if production were to continue at current rates. *** Excludes Antarctica.

Sources: IEA (2018b); BGR (2014).

6.4 Bioenergy

Bioenergy is an important renewable energy option, providing a significant portion of renewables-based electricity and transport fuels in all scenarios in the WEO. Many regions or countries have or are considering policies that will increase the demand for bioenergy in the power and transport sectors further in the future. However, the regions driving this demand growth are not necessarily the same that have available supply of biomass feedstock. For example, the European Union has become, and looks to remain, a major importer of biofuels as it strives to meet its established goals for the share of biofuels in fuel sales.

The bioenergy supply module, added to the WEM for *WEO-2012*, is designed to assess the ability of WEO regions to meet their demand for bioenergy for power generation and biofuels with domestic resources.¹⁷ Where they are not able to do so, the module also simulates the international trade of solid biomass and biofuels. The availability of bioenergy is restricted to renewable sources of biomass feedstock that is not in competition with food.

6.4.1 Supply potentials by region

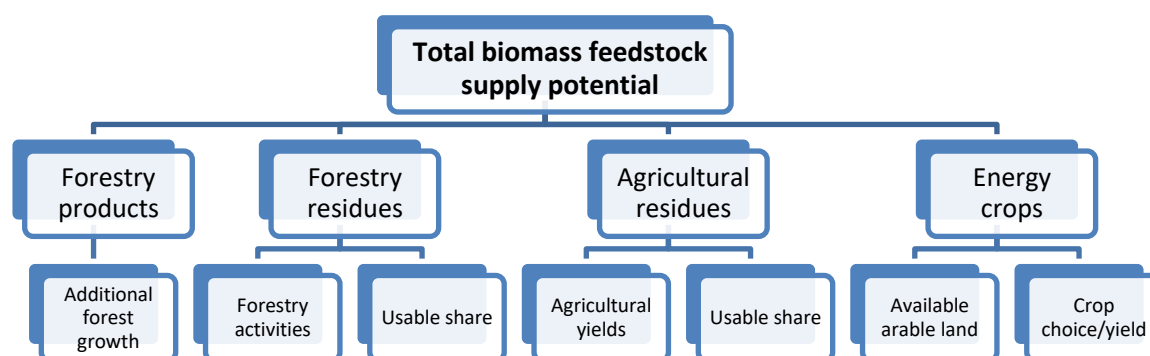
The feedstock supply potentials are built on a wide range of data related to land, crops and food demand, originating largely from the database of the Food and Agriculture Organization of the United Nations (FAO), as well as academic literature and the Global Agro-Ecological Zones (GAEZ) system, a collaborative project involving FAO and the Institute for Applied Systems Analysis (IIASA).

Total supply potentials by region in the bioenergy supply module are the sum of the potential supply for four categories of feedstocks: forestry products, forestry residues, agricultural residues and energy crops (Figure 24). Starting from current activity levels, ramping up collection and delivery of these often diffuse feedstocks requires significant lead times before maximum potential supply levels can be reached. The potential supply

¹⁷ The module does not assess demand or supply related to biogas or waste.

of forestry and agricultural residues is reduced by industrial and residential use to produce heat, as well as demand for traditional uses.

Figure 24: Schematic of biomass supply potentials



Forestry products include only forestry activities, such as harvesting trees and complementary fellings, for the primary purpose of producing power or transport biofuels. The maximum potential availability of forestry products is limited to the expected growth in total forest area per year, after other forestry demands are met, in each region, thereby avoiding direct deforestation.

Forestry residues are those materials, or secondary products, produced from forestry activities where the primary motivation is something other than to produce bioenergy. These include forestry scraps, bark leftover from the timber industry, industrial by-products and waste wood. The maximum potential availability is limited by the level of the related activities and the usable share of the leftover materials.

Agricultural residues are the leftover materials after harvesting crops, such as corn stover, straw and bagasse from sugarcane processing. Data for harvests by region include the following crops: barley, maize (corn), oats, rice, sorghum, wheat, other cereals, rapeseed, soybeans, sunflower seed, and sugarcane. The maximum potential availability is limited by the amount of crops harvested and by the recoverable share of the residues. It is important for a portion of the residues to remain in fields to replenish soil nutrients and maintain yields for future harvests, by helping reduce soil erosion and maintaining water and temperature in the soils. The percentage of these residues that can be made available for energy production in a sustainable manner is region- and crop-specific, and is still being investigated actively.

Energy crops are those grown specifically for energy purposes, including sugar and starch feedstock for ethanol (e.g. corn, sugarcane, and sugar beet), vegetable-oil feedstock for biodiesel (e.g. rapeseed, soybean and oil palm fruit) and lignocellulosic material (e.g. switchgrass, poplar and miscanthus) for advanced biofuels. The maximum potential availability is determined by the available arable land, after taking into account food-related demand for land, crop choice and rising yields over time.

The potential supply from energy crops (million tonnes) is calculated as follows:

$$P_{t,r} = \sum_{l,g,c} (x_{t,r,l,g,c} * y_{t,r,l,g,c} * s_{t,r,c})$$

where, for a given year t and region r ,

- $P_{t,r}$ is the potential biomass feedstock supply from energy crops;
- $x_{t,r,l,g,c}$ is the available land by type l , grade g , and crop c ;
- $y_{t,r,l,g,c}$ is the crop yield; and
- $s_{t,r,c}$ is the share of available land for each crop.

Available land is divided into three grades of land quality (prime, good and marginal) and three types of land (cultivated, unprotected grassland and unprotected forest land).¹⁸ Lower quality grades of land provide lower crop yields. In this assessment, unprotected forest land is not allowed to be converted to crop lands and so is unavailable for bioenergy purposes. Crop yields are defined by region, reflecting the average growing conditions in a region, and are assumed to continue to improve moderately through 2035. Crop choice is influenced by currently favoured crops for bioenergy, the changing economics of feedstock (through increased yields and relative attractiveness compared to the fossil fuel alternative), and policy development. For example, policy goals for advanced biofuels will increase demand for lignocellulosic energy crops, decreasing the share of land devoted to conventional feedstock.

6.4.2 Supply to meet demand

Demand for biomass feedstock is based on demand projections in the WEO for both the power and transport sectors (demand for other sectors is assumed to be met from domestic resources). To meet demand, domestic supplies are given priority; the remainder is covered through international markets. The model is calibrated to meet existing trade flows reported in a range of industry reports, including the F.O. Licht series “World Ethanol & Biofuel Report”, and government reports, such as regional Global Agricultural Information Network (GAIN) reports on biofuels by the US Department of Agriculture.

6.4.3 Domestic supply

Biomass feedstock competes to meet demand on the basis of conversion costs, including feedstock prices and the energy contents of feedstock. Several biomass feedstock types can be used for both power generation and the production of biofuels. These include forestry products, forestry residues and agricultural residues. Where this is the case, the net present values for both uses are compared and ranked, based on technology cost data from WEM and IEA’s Mobility Model. According to rank, available biomass feedstock supplies are allocated. Domestic supply of biofuels is limited by refining capacity. In the near term, this is restricted by existing refineries and those already under construction or planned.

6.4.4 Global trade

The model uses a global trade matrix to match unsatisfied demand with available supply on a least-cost basis, including transportation costs. Transportation costs between regions include both average over-land and by-sea costs. Three products are traded: ethanol, biodiesel and solid biomass pellets. The latter are high-density uniform products that can be made from residues and other feedstock, and their uniformity and density make handling and transportation easier and less expensive over long distances compared with other bioenergy resources. The conversion of biomass feedstock to biofuels occurs in the exporting region, therefore conversion costs are calculated based on the technology costs in the exporting region. Importing regions choose suppliers based on least-cost available supplies (including transportation costs). Exporting regions make supplies available to importing regions willing to pay the highest price.

6.5 Oil and gas methane emissions model

6.5.1 Global estimate of methane emissions from oil and gas operations

Our approach to estimating methane emissions from global oil and gas operations relies on generating country-specific and production type-specific emission intensities that are applied to production and consumption data on a country-by-country basis. Our starting point is to generate emission intensities for

¹⁸ Classifications and data from Fischer et al. (2011), Scarcity and abundance of land resources: competing uses and the shrinking land resource base. SOLAW Background Thematic Report - TR02.

upstream and downstream oil and gas in the United States (Table 9). The 2017 US Greenhouse Gas Inventory is used for this along with a range of other data sources, including our survey of companies and countries. The hydrocarbon-, segment- and production-specific emission intensities are then further segregated into fugitive, vented and incomplete flaring emissions to give a total of 19 separate emission intensities.

Table 9: Categories of emission sources and emissions intensities in the United States

Hydrocarbon	Segment	Production type	Emissions type	Emission intensity (toe CH ₄ /toe fuel)
Oil	Upstream	Onshore conventional	Vented	0.37%
Oil	Upstream	Onshore conventional	Fugitive	0.11%
Oil	Upstream	Offshore	Vented	0.16%
Oil	Upstream	Offshore	Fugitive	0.05%
Oil	Upstream	Unconventional oil	Vented	0.55%
Oil	Upstream	Unconventional oil	Fugitive	0.17%
Oil	Downstream		Vented	0.002%
Oil	Downstream		Fugitive	0.003%
Oil		Onshore conventional	Incomplete-flare	
Oil		Offshore	Incomplete-flare	
Oil		Unconventional oil	Incomplete-flare	
Gas	Upstream	Onshore conventional	Vented	0.38%
Gas	Upstream	Onshore conventional	Fugitive	0.26%
Gas	Upstream	Offshore	Vented	0.13%
Gas	Upstream	Offshore	Fugitive	0.09%
Gas	Upstream	Unconventional gas	Vented	0.65%
Gas	Upstream	Unconventional gas	Fugitive	0.44%
Gas	Downstream		Vented	0.10%
Gas	Downstream		Fugitive	0.30%

Note: Emission intensities are given here as the energy ratio of tonne of oil-equivalent (toe) methane emitted to tonne of oil equivalent fuel. For natural gas, since this is not 100% methane, ratios differ slightly if given as the volume ratio or mass ratio. For example, the emission intensity for upstream onshore conventional vented emissions in the United States if stated as a volume ratio is 0.36% rather than 0.38% as shown for the energy ratio.

The US emissions intensities are then scaled to provide emission intensities in all other countries. This scaling is based upon a range of auxiliary country-specific data. For the upstream emission intensities, the scaling is based on the age of infrastructure and types of operator within each country (namely international oil companies, independent companies or national oil companies). For downstream emission intensities, country-specific scaling factors were based upon the extent of oil and gas pipeline networks and oil refining capacity and utilisation. The strength of regulation and oversight, incorporating government effectiveness, regulatory quality and the rule of law as given by the Worldwide Governance Indicators compiled by the World Bank (2017), affects the scaling of all intensities. Some adjustments were made to the scaling factors in a limited number of countries to take into account other data that were made available (where this was considered to be sufficiently robust).

Table 10 provides the resultant scaling factors in the top oil and gas producers (the countries listed cover 95% of global oil and gas production). These scaling factors are directly used to modify the emissions intensities in Table 9. For example, the vented emission intensity of onshore conventional gas production in Russia is taken as $0.38\% \times 1.9 = 0.72\%$. These intensities are finally applied to the production (for upstream emissions) or consumption (for downstream emissions) of oil and gas within each country.

Table 10: Scaling factors applied to emission intensities in the United States

Country	Oil and gas production in 2016 mtoe	Oil		Gas	
		Upstream	Downstream	Upstream	Downstream
United States	1 169	1.0	1.0	1.0	1.0
Russia	1 092	1.9	1.6	1.9	1.8
Saudi Arabia	671	1.4	1.0	1.4	1.1
Iran	372	2.6	2.2	2.4	2.5
Canada	356	1.0	0.8	1.0	0.7
China	316	1.2	0.9	1.1	0.9
UAE	238	1.3	0.8	1.2	0.8
Iraq	234	6.0	5.8	6.1	7.1
Qatar	226	1.1	0.9	1.2	0.8
Norway	198	1.0	0.8	1.0	0.7
Kuwait	170	1.6	1.2	1.5	1.3
Algeria	154	2.7	2.4	2.7	2.8
Brazil	151	1.5	1.3	1.5	1.3
Mexico	150	1.4	1.1	1.4	1.2
Venezuela	143	7.4	7.0	7.4	8.6
Nigeria	127	3.0	2.7	3.0	3.3
Kazakhstan	112	1.7	1.2	1.6	1.3
Indonesia	111	1.6	1.3	1.6	1.5
Malaysia	93	1.1	0.9	1.0	0.9
Angola	91	3.3	3.2	3.7	3.8
Australia	89	1.0	0.8	0.9	0.7
United Kingdom	86	1.0	0.8	1.0	0.8
Oman	79	1.4	1.0	1.3	1.0
Turkmenistan	77	5.7	5.3	5.6	6.5
India	67	1.4	1.2	1.5	1.2
Egypt	66	2.2	2.0	2.1	2.2
Argentina	63	2.1	1.8	2.0	2.0
Azerbaijan	57	1.9	1.5	1.7	1.6
Uzbekistan	54	3.8	3.3	3.7	4.0
Colombia	53	1.4	1.1	1.4	1.2
Thailand	43	1.3	1.1	1.2	1.1
Netherlands	37	1.0	0.8	1.0	0.7
Trinidad	37	1.4	1.1	1.4	1.1
Pakistan	32	2.3	2.1	2.4	2.4

6.5.2 Marginal abatement cost curves

To construct the marginal abatement cost curves presented in *WEO-2018*, the 19 emissions sources listed in Table 9 were further separated into 86 equipment-specific emissions sources (Table 11). The allocation of emissions from each of the 19 emissions sources to these 86 equipment-specific sources was generally based on proportions from the United States. However a number of modifications were made for countries based on other data sources and discussions with relevant stakeholders. Some of the largest changes made were for the proportion of emissions from: pneumatic controllers (which are less prevalent in many countries outside North America), LNG liquefaction (which were assumed to be larger in LNG exporting countries), and associated gas venting.

Table 11: Equipment-specific emissions sources used in the marginal abatement cost curves

Equipment source	Hydrocarbon	Segment
Large Tanks w/Flares	Oil	Upstream
Large Tanks w/VRU	Oil	Upstream
Large Tanks w/o Control	Oil	Upstream
Small Tanks w/Flares	Oil	Upstream
Small Tanks w/o Flares	Oil	Upstream

Equipment source	Hydrocarbon	Segment
Malfunctioning Separator Dump Valves	Oil	Upstream
Pneumatic Devices, High Bleed	Oil	Upstream
Pneumatic Devices, Low Bleed	Oil	Upstream
Pneumatic Devices, Int Bleed	Oil	Upstream
Chemical Injection Pumps	Oil	Upstream
Vessel Blowdowns	Oil	Upstream
Compressor Blowdowns	Oil	Upstream
Compressor Starts	Oil	Upstream
Associated Gas Venting	Oil	Upstream
Well Completion Venting (less HF Completions)	Oil	Upstream
Well Workovers	Oil	Upstream
HF Well Completions, Uncontrolled	Oil	Upstream
HF Well Completions, Controlled	Oil	Upstream
Pipeline Pigging	Oil	Upstream
Tanks	Oil	Downstream
Truck Loading	Oil	Downstream
Marine Loading	Oil	Downstream
Rail Loading	Oil	Downstream
Pump Station Maintenance	Oil	Downstream
Pipelining Pigging	Oil	Downstream
Uncontrolled Blowdowns	Oil	Downstream
Asphalt Blowing	Oil	Downstream
Process Vents	Oil	Downstream
CEMS	Oil	Downstream
Production Compressor Vented	Gas	Upstream
Gas Well Completions without Hydraulic Fracturing	Gas	Upstream
Gas Well Workovers without Hydraulic Fracturing	Gas	Upstream
Hydraulic Fracturing Completions and Workovers that vent	Gas	Upstream
Hydraulic Fracturing Completions and Workovers with RECs	Gas	Upstream
Well Drilling	Gas	Upstream
Pneumatic Device Vents (Low Bleed)	Gas	Upstream
Pneumatic Device Vents (High Bleed)	Gas	Upstream
Pneumatic Device Vents (Intermittent Bleed)	Gas	Upstream
Chemical Injection Pumps	Gas	Upstream
Kimray Pumps	Gas	Upstream
Dehydrator Vents	Gas	Upstream
Large Tanks w/VRU	Gas	Upstream
Large Tanks w/o Control	Gas	Upstream
Small Tanks w/o Flares	Gas	Upstream
Malfunctioning Separator Dump Valves	Gas	Upstream
Gas Engines	Gas	Upstream
Well Clean Ups (LP Gas Wells) - Vent Using Plungers	Gas	Upstream
Well Clean Ups (LP Gas Wells) - Vent Without Using Plungers	Gas	Upstream
Vessel BD	Gas	Upstream
Pipeline BD	Gas	Upstream
Compressor BD	Gas	Upstream
Compressor Starts	Gas	Upstream
G&B Station Episodic Events	Gas	Upstream
Pressure Relief Valves	Gas	Upstream
Mishaps	Gas	Upstream
Recip. Compressors	Gas	Upstream
Centrifugal Compressors (wet seals)	Gas	Upstream
Centrifugal Compressors (dry seals)	Gas	Upstream
Dehydrators	Gas	Upstream
AGR Vents	Gas	Upstream
Pneumatic Devices	Gas	Upstream
Blowdowns/Venting	Gas	Upstream
Reciprocating Compressor	Gas	Downstream

Equipment source	Hydrocarbon	Segment
Centrifugal Compressor (wet seals)	Gas	Downstream
Centrifugal Compressor (dry seals)	Gas	Downstream
Reciprocating Compressor	Gas	Downstream
Dehydrator vents (Transmission)	Gas	Downstream
Dehydrator vents (Storage)	Gas	Downstream
Pneumatic Devices (High Bleed)	Gas	Downstream
Pneumatic Devices (Intermittent Bleed)	Gas	Downstream
Pneumatic Devices (Low Bleed)	Gas	Downstream
Pneumatic Devices (High Bleed)	Gas	Downstream
Pneumatic Devices (Intermittent Bleed)	Gas	Downstream
Pneumatic Devices (Low Bleed)	Gas	Downstream
Pipeline venting	Gas	Downstream
Station Venting Transmission	Gas	Downstream
Station Venting Storage	Gas	Downstream
LNG Reciprocating Compressors Vented	Gas	Downstream
LNG Centrifugal Compressors Vented	Gas	Downstream
LNG Station venting	Gas	Downstream
LNG Reciprocating Compressors Vented	Gas	Downstream
LNG Centrifugal Compressors Vented	Gas	Downstream
LNG Station venting	Gas	Downstream
Pressure Relief Valve Releases	Gas	Downstream
Pipeline Blowdown	Gas	Downstream
Mishaps (Dig-ins)	Gas	Downstream

The abatement options included in the marginal abatement cost curves to reduce emissions from these sources are listed in Table 12. We are unable to provide the specific costs and applicability factors for these as it is based on proprietary information gathered by ICF (although see ICF (2016a) and ICF (2016b) for data that has made available publically). Costs were again based upon information from the United States. However labour costs, whether the equipment is imported or manufactured domestically (which impacts the capital costs and whether or not import taxes are levied), and capital costs were modified based on country-specific or region-specific information. Similarly the applicability factors are modified based on other data that is available publically (for example that solar-powered electric pumps cannot be deployed as widely in high-latitude countries).

Leak detection and repair (LDAR) programmes are the key mechanism to mitigate fugitive emissions from the production, transmission or distribution segments of the value chain. The costs of inspection differ depending on the segment in question since it takes longer to inspect a compressor on a transmission pipeline than in a production facility. It is assumed that inspections can be carried out annually, twice a year, quarterly or monthly, with each option included as a separate mitigation option in the marginal abatement cost curves. Annual inspections are assumed to mitigate 40% of fugitive emissions, biannual inspections mitigate an additional 20%, quarterly inspections mitigate an additional 10%, and monthly inspections mitigate an additional 5%. Implementing a monthly LDAR programme therefore reduces fugitive emissions by 85%; the remaining 15% cannot be avoided. As the frequency of implementing each programme increases, so does the cost per unit of methane saved. For example, while the incremental cost of a biannual inspection programme is the same as that of an annual inspection, the incremental volume of methane saved is lower (20% rather than 40%). Nevertheless, LDAR programmes remain some of the most cost-effective mitigation options available, i.e. they tend to comprise a large proportion of the positive net present value options in countries.

Table 12: Abatement options for methane emissions from oil and gas operations

Abatement option
Blowdown Capture and Route to Fuel System (per Compressor)
Blowdown Capture and Route to Fuel System (per Plant)
Early replacement of high-bleed devices with low-bleed devices
Early replacement of intermittent-bleed devices with low-bleed devices
Install Flares-Completion
Install Flares-Portable
Install Flares-Portable Completions Workovers WO HF
Install Flares-Portable WO Plunger Lifts
Install Flares-Stranded Gas Venting
Install Flares-Venting
Install New Methane Reducing Catalyst in Engine
Install Non Mechanical Vapor Recovery Unit
Install Plunger Lift Systems in Gas Wells
Install small flare
Install Vapor Recovery Units
LDAR Gathering
LDAR LDC - Large
LDAR LDC - MRR
LDAR Processing
LDAR Reciprocating Compressor Non-seal
LDAR Transmission
LDAR Wells
Mechanical Pumping for Liquids Unloading
Pipeline Pump-Down Before Maintenance
Redesign Blowdown Systems and Alter ESD Practices
Reduced Emission Completion
Replace Kimray Pumps with Electric Pumps
Replace Pneumatic Chemical Injection Pumps with Electric Pumps
Replace Pneumatic Chemical Injection Pumps with Solar Electric Pumps
Replace with Instrument Air Systems
Replace with Electric Motor
Replace with Servo Motors
Replace with Solenoid Controls
Replacement of Reciprocating Compressor Rod Packing Systems
Route to existing flare - Large Dehydrators
Route to existing flare - Large Tanks
Route to flare - Small Dehydrators
Route to existing flare - Small Tanks
Route Vent Vapors to tank
Wet Seal Degassing Recovery System for Centrifugal Compressors
Wet Seal Retrofit to Dry Seal Compressor
Microturbine
Mini-LNG
Mini-GTL
Mini-CNG

6.5.3 Well-head prices used in net present value calculation

Since natural gas is a valuable product, the methane that is recovered can often be sold. This means that deploying certain abatement technologies can result in overall savings if the net value received for the methane sold is greater than the cost of the technology. Well-head prices are used in each country to determine the value of the methane captured. As described in *WEO-2018*, the marginal abatement cost curves examine this issue from a global, societal perspective. The credit obtained for selling the gas is therefore applied regardless of the contractual arrangements necessary and the prices assume that there are

no domestic consumption subsidies (as the gas could be sold on the international market at a greater price). The well-head gas prices used could therefore be substantially different from subsidised domestic gas prices.

The natural gas import prices listed in *WEO-2018 (IEA, 2018b)* are the starting point for the well-head prices within each country. To estimate well-head prices over time, each country is assigned to be either an importer or an exporter based on the trends seen in the New Policies Scenario. For importing countries, any gas that would be saved from avoiding leaks would displace imports. The well-head price is therefore taken as the import price minus the cost of local transport and various taxes that may be levied (assumed to be around 15% of the import price). For exporting countries, the relevant well-head price is taken as the import price in their largest export market net-backed to the emissions source. For the net-back, allowance is made for transport costs (including liquefaction and shipping or pipeline transport), fees and taxes. For example, in Russia the export price is taken as the import price in Europe (\$4.9/MBtu in 2016). Export taxes of 40% are then subtracted along with a further \$0.5/MBtu to cover the cost of transport by pipeline. This gives a well-head gas price in Russia in 2016 of \$2.4/MBtu. In the United States and Canada, the well-head price is taken as the Henry Hub price minus 15% (to cover the cost of local transportation and fees).

The costs and revenue for each technology or abatement measure is converted into net present value using a discount rate of 10% and divided by the volume of emissions saved to give the cost in dollars per million British thermal units (MBtu).

6.5.4 Other notes on marginal abatement cost curves

To aid visualisation of the marginal abatement cost curves, the costs and savings from multiple technologies are aggregated together. Within each country, the abatement options that could be applied to each of the 19 emission sources listed in Table 9 are aggregated into three cost steps. These steps roughly represent the cheapest 50% of reductions, the next 30% of reductions and the final of 20% reductions.

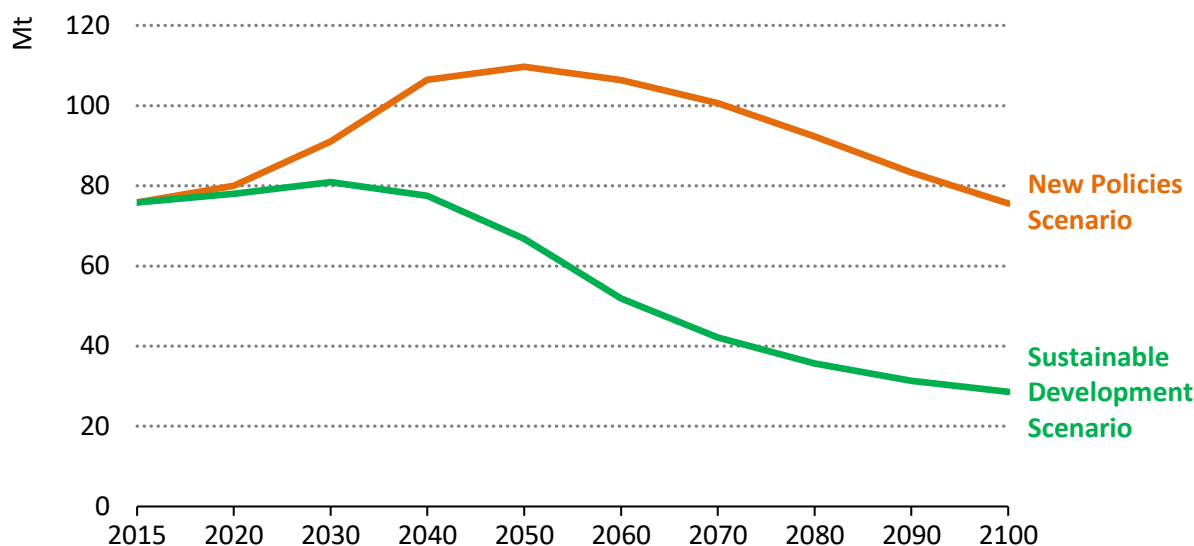
6.5.5 Modelling of temperature increases from methane abatement

The climate model MAGICC, widely used in studies assessed by the IPCC, is used to estimate the impact of the oil and gas methane emissions trajectories on the average global surface temperature rise. An important consideration in assessing the temperature rise is the date to examine. If the aim of climate policy is to limit peak warming, then the key factor to consider in choosing this date is the time when the global temperature rise will peak (Allen et al., 2016). We choose to focus on the temperature rise in 2100 partly because this reflects the public and academic discourse surrounding the interpretation of the long-term temperature goals in the Paris Agreement and partly because if global CO₂ emissions were to reach net-zero in the Sustainable Development Scenario in 2100 this is approximately the date when the global temperature rise would peak. If we were to examine a closer date, say 2050 rather than 2100, the temperature impacts of policies to reduce methane emissions would be larger. This date is used for both the temperature assessment in the New Policies Scenario and the Sustainable Development Scenario for consistency.

To carry out this calculation in MAGICC, it is necessary to extend the projection for the “baseline” level of methane emissions in the New Policies and Sustainable Development Scenarios from 2040 to 2100. Assumptions are made about the levels of fossil-fuel consumption consistent with the general ambition of the scenarios. For example, if CO₂ emissions in the Sustainable Development Scenario drop to zero by 2100, this would mean that fossil-fuel consumption would be much lower than at present. It is important to recognise that even if there are no net CO₂ emissions in 2100, this does not necessarily mean that no fossil fuels will be consumed: fossil fuels are not combusted in some sectors (notably in petrochemicals); fossil-fuel combustion can be equipped with carbon capture and storage to mitigate CO₂ emissions; and the use of some “negative-emissions” technologies could offset some level of fossil-fuel combustion.

The trajectory for total oil and gas methane emissions in the absence of any mitigation options is shown in Figure 25. For the methane trajectories that include mitigation measures, the level of reductions relative to the baseline level is kept constant from 2040 onwards on a global basis separately for oil and gas. All other variables (including the other greenhouse gases [such as N₂O, HFCs etc.]) are kept constant to isolate the impact of the methane abatement policies on the median temperature rise in 2100.

Figure 25 ▸ Methane emissions from oil and gas operations in the New Policies and Sustainable Development scenarios with no explicit methane abatement measures



7 Emissions

7.1 CO₂ emissions

As energy-related CO₂ emissions account for the lion's share of global greenhouse gas emissions, one of the important outputs of the WEM is region by region CO₂ emissions from fuel combustion. For each WEM region, sector and fuel, CO₂ emissions from fuel combustion are calculated by multiplying energy demand by an implied CO₂ content factor. The implied CO₂ content factors for coal, oil and gas differ between sectors and regions, reflecting the product mix. They have been calculated as an average of the past three years from IEA energy-related sectoral approach CO₂ data for all WEM regions and are assumed to remain constant over the projection period (IEA, 2017d and 2018b).

7.2 Non-CO₂ greenhouse gases and CO₂ process emissions

For the *WEO Special Report Energy and Climate Change*, a detailed analysis of process-related CO₂ emissions from various industrial sources by WEM region was conducted. For the estimation a Tier 1 or Tier 2 method has been used, which in general means that emissions have been estimated based on the production of industrial materials and an emissions factor from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories. So far the analysis is limited to the most important sources of industrial process emissions:

- Mineral industry: cement, lime, limestone use, soda ash use
- Metal industry: primary aluminium
- Chemical industry: ammonia, methanol, ethylene, soda ash
- Non-energy products: lubricants and paraffins

Greenhouse-gas emissions beyond energy- and process- related CO₂ and methane emissions from upstream oil and gas production that are consistent with the energy scenarios developed for the *WEO-2012* have been estimated in co-operation with the Environment Division at the Organisation for Economic Cooperation and Development (OECD). Based on energy supply, transformation and demand from *WEM*, projections were derived from the OECD ENV-Linkages model (OECD, 2012a). These include projections for other methane emissions, nitrous oxide (N₂O), and F-gases. The last category includes hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride (SF₆) from several sectors, mainly industry. Projections for emissions from land use, land-use change and forestry are taken from the Baseline Scenario in OECD (2012b) and are therefore indicative. They are kept constant across the scenarios, but decline over time.

7.3 Air pollution

Emissions of major air pollutants resulting from the WEO energy scenarios have been estimated in co-operation with the International Institute for Applied Systems Analysis (IIASA). Using the IIASA GAINS model, estimates have been made for the following local air pollutants: sulphur dioxide (SO₂), nitrogen oxides (NO_x) and PM_{2.5}.¹⁹ More information can be found in the WEO Special Report on [Energy and Air Pollution](#) as well as in a previous detailed report outlining the approach, results and information about health impacts, as well as pollution control costs, available on the WEO documentation webpage: <http://www.iea.org/weo/weomodel/>.

8 Investment²⁰

8.1 Investment in the energy supply chain

Projections of supply-side investment requirements by scenario in the WEO cover the period 2018-2040 and are derived from the WEM energy supply and demand modules. Relative to the Current Policies and New Policies Scenario, the WEM incorporates an economic analysis of the net change in investment by energy suppliers and energy consumers; the net change in energy import bills and export revenues; and how the cost to consumers of investing in more energy-efficient equipment compares with the savings they make through lower expenditure on energy bills. All investments and consumers' savings in energy bills are expressed in year-2017 dollars. The calculation of the investment requirements for power generation and fossil-fuel supply involves the following steps for each region:

- New capacity needs for production, transportation and (where appropriate) transformation were calculated on the basis of projected supply trends, estimated rates of retirement of the existing supply infrastructure and decline rates for oil and gas production.
- Unit capital cost estimates were compiled for each component in the supply chain. These costs were then adjusted for each year of the projection period using projected rates of change based on a detailed analysis of the potential for technology-driven cost reductions and on country-specific factors.
- Incremental capacity needs were multiplied by unit costs to yield the amount of investment needed.

The results are presented by decade. The estimates of investment in the current decade take account of projects that have already been decided and expenditures that have already been incurred. The convention of attributing capital expenditures to the year in which the plant in question becomes operational has been

¹⁹ Fine particulate matter is particulate matter that is 2.5 micrometres in diameter and less; it is also known as PM_{2.5} or respirable particles because they penetrate the respiratory system further than larger particles.

²⁰ Assumptions for specific investment cost in power generation and for energy efficiency in end-uses can be found on [the WEO documentation page: http://www.iea.org/weo/weomodel/](http://www.iea.org/weo/weomodel/)

adopted (i.e. overnight costs). In other words, no attempt has been made to estimate the lead times for each category of project. This is because of the difficulties in estimating lead times and how they might evolve in the future.

For the purposes of this study, investment is defined as capital expenditure only. It does not include spending that is usually classified as operation and maintenance.

8.1.1 Short-term oil and natural gas upstream investment

Projections of upstream investment are based on a combination of bottom-up and top-down approaches. The former involves a detailed analysis of the plans and prospects for oil and gas industry investment over the period 2017 to 2021, with the aim of determining how much the industry is planning to invest in response to current prices and to the need for new capacity and of assessing the resulting additions to production capacity. This analysis is based on a survey of the capital-spending programmes of 70 of the largest upstream oil and gas companies (national and international companies and pure exploration and production companies), covering actual capital spending from 2000 to 2015 and their plans or forecasts of spending through to 2020 when available. Companies were selected on the basis of their size as measured by their production and reserves, though geographical spread and data availability also played a role. The surveyed companies account for close to 80% of world oil production and reserves, and 2/3 of gas production reserves. Total industry investment was calculated by adjusting upwards the spending of the 70 companies, according to their share of world oil and gas production for each year.

Data was obtained from companies' annual and financial reports, corporate presentations, press reports, trade publications and direct contacts in the industry.

8.1.2 Long-term oil, natural gas and coal supply-side investment

Projections of long-term oil, gas and coal supply-side investment requirements are generated in the respective supply-side modules. The methodology establishes a direct link over time between new production capacity brought on stream, the cash flow generated and the investments required. The cost of new capacity is estimated from a set of variables: size of the reserves, degree of depletion, location type of resource, technology employed, technology learning, and underlying assumptions on cost inflation (itself a function of oil prices in the oil and gas supply-side modules).

8.1.3 Power generation investment

Very large investments in electricity-supply infrastructure will be needed over the Outlook period to meet rising electricity demand and to replace or refurbish obsolete generating assets and network facilities. The investments in generating assets are a straightforward calculation multiplying the capital cost (\$/kW) for each generating technology by the corresponding capacity additions for each modelled region/country. The investment costs assumed in the power generation sector are based on a review of the latest country data available and on assumptions of their evolution over the projection period. They represent overnight costs for all technologies. For renewable sources and for plants fitted with carbon capture and storage (CCS) facilities, the projected investment costs result from the various levels of deployment in the different scenarios. A spreadsheet outlining the indicative overnight costs and other relevant investment assumptions for all technologies by region may be found on the WEO model documentation page (<http://www.iea.org/weo/weomodel/>). For investment in transmission and distribution networks, please refer to section 4.2.

8.2 Demand-side investments

Demand-side investments are consumers' outlays for the purchase of durable goods, that is, end-use equipment. For the WEO Special Report [World Energy Investment Outlook \(IEA, 2014\)](#), a detailed analysis was

carried out to project procurement capital, i.e. the money spent by end-users on energy-consuming products. This does not include all of the spending, only the amount that is spent (including taxes and freight costs) to procure equipment that is more efficient than a baseline, established by the 2013 average efficiency of different products and sectors. The investment cost include labour costs that are directly related to an installation, while additional costs can arise from administrative procedures, legal protection and border clearances, which are also included in the cost estimate. In other words, this calculation reflects the additional amount that consumers have to pay for higher energy efficiency over the period to 2040.

For the 25 WEM regions and for each end-use sector (industry, transport and buildings), the investment needed to move to greater efficiency levels have been analysed. The analysis is based on investment cost, stock turnover and the economic return required across sub-sectors in industry, across modes in transport and across end-uses in buildings. Efficiency levels and investment costs have been updated in 2014 and verified via a survey sent to key stakeholders in industry, academia and research bodies.

In the road transport sector, the costs of efficiency improvements and of a switch to alternative fuel vehicles are used as an input to the model to determine each options cost-competitiveness. Based on the outcome of this analysis, the investment needs are then determined by multiplying the number of vehicles sold in each year by the costs of each vehicle. Detailed figures from Airbus/Boeing were used to assess the need for new planes and the increased capital cost of increasing efficiency in the aviation sector.

Outputs include the additional annual capital needs for the 25 regions and three end-use sectors. The impact of the energy savings on consumers' bills is also analysed. The sectoral end-user prices (including taxes) have been used to assess the overall impact of the policies on consumers over time. The results also include the impact on main importing countries.

9 Energy access

9.1 Defining modern energy access

There is no single internationally-accepted and internationally-adopted definition of modern energy access.

Yet significant commonality exists across definitions, including:

- Household access to a minimum level of electricity
- Household access to safer and more sustainable (i.e. minimum harmful effects on health and the environment as possible) cooking and heating fuels and stoves
- Access to modern energy that enables productive economic activity, e.g. mechanical power for agriculture, textile and other industries
- Access to modern energy for public services, e.g. electricity for health facilities, schools and street lighting

All of these elements are crucial to economic and social development, as are a number of related issues that are sometimes referred to collectively as "quality of supply", such as technical availability, adequacy, reliability, convenience, safety and affordability.

The data and projections presented in the WEO focus on two elements of energy access: a household having access to electricity and to clean cooking facilities. The IEA defines energy access as "*a household having reliable and affordable access to both clean cooking facilities and to electricity, which is enough to supply a basic bundle of energy services initially, and then an increasing level of electricity over time to reach the regional average*". This energy access definition serves as a benchmark to measure progress towards goal SDG 7.1 and as a metric for our forward-looking analysis.

Electricity access entails a household having initial access to sufficient electricity to power a basic bundle of energy services – at a minimum, several lightbulbs, task lighting (such as a flashlight), phone charging and a radio – with the level of service capable of growing over time. In our projections, the average household who has gained access has enough electricity to power four lightbulbs operating at five hours per day, one refrigerator, a fan operating 6 hours per day, a mobile phone charger and a television operating 4 hours per day, which equates to an annual electricity consumption of 1 250 kWh per household with standard appliances, and 420 kWh with efficient appliances. This service-level definition cannot be applied to the measurement of actual data simply because the level of data required does not exist in a large number of cases. As a result, our electricity access databases focus on a simpler binary measure of those that have a connection to an electricity grid, or have a renewable off- or mini-grid connection of sufficient capacity to deliver the minimum bundle of energy services mentioned above.

Access to clean cooking facilities means access to (and primary use of) modern fuels and technologies, including natural gas, liquefied petroleum gas (LPG), electricity and biogas, or improved biomass cookstoves (ICS) that have considerably lower emissions and higher efficiencies than traditional three-stone fires for cooking. Currently, very few ICS models attain this lower emissions target, particularly under real-world cooking conditions. Therefore, our clean cooking access database refers to households that rely primarily on fuels other than biomass (such as fuelwood, charcoal, tree leaves, crop residues and animal dung), coal or kerosene for cooking. The main sources are the World Health Organisation (WHO) Household Energy Database and the IEA Energy Balances.

9.2 Outlook for modern energy access

9.2.1 Outlook for electricity access

The IEA's electricity access database²¹ provides valuable information about the current electrification rates in a large number of countries. In order to provide an outlook for electricity access in the next decades, a model able to generate projections of electrification rates by region has been developed. The projections are based on an econometric panel model that regresses historic electrification rates of different countries over many variables, to test their level of significance. Variables that were determined statistically significant and consequently included in the equations are per-capita income, demographic growth, urbanisation, fuel prices, level of subsidies, technological advances, energy consumption, and energy access programmes.

9.2.2 Outlook for clean cooking access

Our baseline data on the traditional use of biomass for cooking is based on the World Health Organization's (WHO) Global Health Observatory estimates of reliance on solid fuels.²² To provide an outlook for the number of people relying on the traditional use of biomass in the next decades, a regional model was developed under the New Policies Scenario assumptions. Reliance on biomass rates of different countries is projected using an econometric panel model estimated from a historical time series. Variables that were determined statistically significant and consequently included in the equations are per-capita income, demographic growth, urbanisation level, level of prices of alternative modern fuels, subsidies to alternative modern fuel consumption, technological advances and clean cooking programmes.

For more detail on the energy access analysis see also the dedicated section on the WEO website: www.iea.org/energyaccess/methodology/.

²¹ <http://www.iea.org/energyaccess/database/>

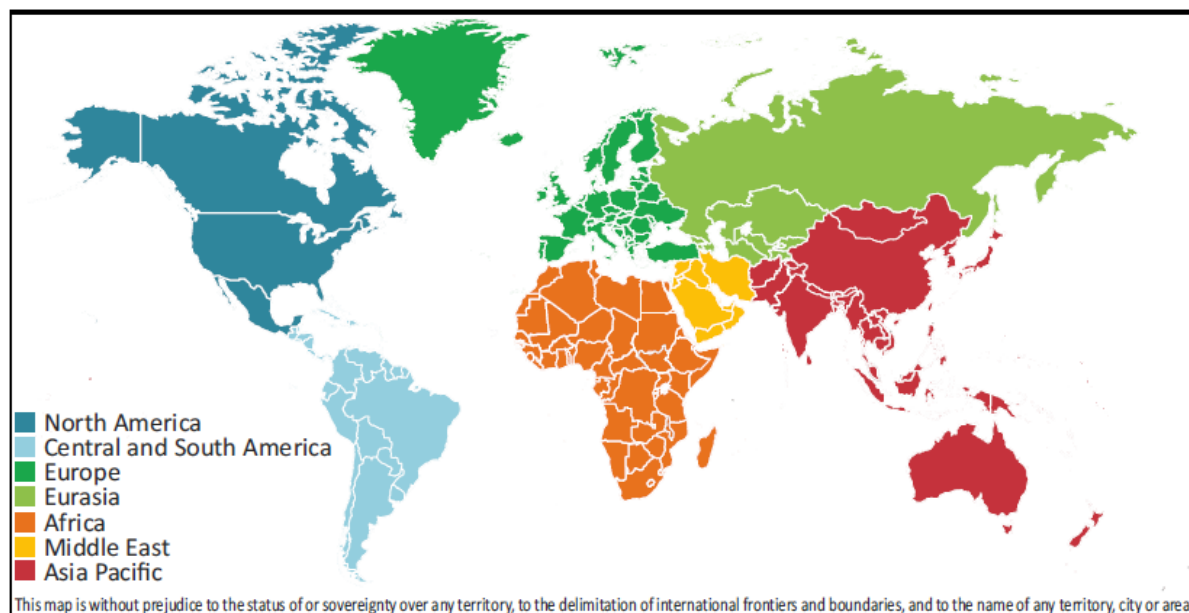
²² For more information, see www.who.int/gho/phe/indoor_air_pollution/en/index.html

Annex 1: WEM regional definitions

A1.1 World Energy Outlook (WEO) publication

In several tables of this methodology document, as well as in the WEO publication itself, results from the WEM model are often presented with the below regional groupings.

Figure 26: Main regional groupings in WEO publication



North America: Canada, Mexico and the United States.

Central and South America: Argentina, Bolivia, Bolivarian Republic of Venezuela, Brazil, Chile, Colombia, Costa Rica, Cuba, Curaçao, Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Nicaragua, Panama, Paraguay, Peru, Suriname, Trinidad and Tobago, Uruguay, and other countries and territories.²³

Europe: Includes European Union regional grouping and Albania, Belarus, Bosnia and Herzegovina, Iceland, Israel²⁴, Gibraltar, Kosovo, Montenegro, Norway, Serbia, Switzerland, the Former Yugoslav Republic of Macedonia, the Republic of Moldova, Turkey and Ukraine.

European Union: Austria, Belgium, Bulgaria, Croatia, Cyprus^{25,26}, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, the Slovak Republic, Slovenia, Spain, Sweden and the United Kingdom.

²³ Individual data are not available and are estimated in aggregate for: Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, Bonaire, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), French Guiana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, Saba, Saint Eustatius, Saint Kitts and Nevis, Saint Lucia, Saint Vincent and the Grenadines, Saint Maarten, Turks and Caicos Islands.

²⁴ The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

²⁵ Note by Turkey: The information in this document with reference to “Cyprus” relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of United Nations, Turkey shall preserve its position concerning the “Cyprus issue”.

Africa: Includes North Africa and Sub-Saharan Africa regional groupings.

North Africa: Algeria, Egypt, Libya, Morocco and Tunisia.

Sub-Saharan Africa: Angola, Benin, Botswana, Cameroon, Republic of the Congo, Côte d'Ivoire, Democratic Republic of the Congo, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Mauritius, Mozambique, Namibia, Niger, Nigeria, Senegal, South Africa, South Sudan, Sudan, United Republic of Tanzania, Togo, Zambia, Zimbabwe and other countries and territories.²⁷

Middle East: Bahrain, the Islamic Republic of Iran, Iraq, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, the Syrian Arab Republic, the United Arab Emirates and Yemen.

Eurasia: Includes Caspian regional grouping and the Russian Federation.

Caspian: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan.

Asia Pacific: Includes Southeast Asia regional grouping and Australia, Bangladesh, China, Chinese Taipei, India, Japan, Korea, Democratic People's Republic of Korea, Mongolia, Nepal, New Zealand, Pakistan, Sri Lanka, and other countries and territories.²⁸

China: Refers to the People's Republic of China, including Hong Kong.

Southeast Asia: Brunei Darussalam, Cambodia, Indonesia, Lao People's Democratic Republic, Malaysia, Myanmar, Philippines, Singapore, Thailand and Viet Nam. These countries are all members of the Association of Southeast Asian Nations (ASEAN).

A1.2 Demand module

The *WEM* demand module is made up of 25 regional models of which Brazil, Canada, Chile, China, India, Indonesia, Japan, Korea, Mexico, Russia, South Africa and the United States are modelled on an individual country basis. These 12 countries in 2014 accounted for: 68% of world CO₂ emissions from fuel combustion, 65% of global fossil fuel demand, 61% of world GDP (PPP) and 55% of world population.

In tables of this methodology document, the 25 *WEM* regions are grouped in the following manner:

Africa: Algeria, Angola, Benin, Botswana, Cameroon, Congo, Côte d'Ivoire, Democratic Republic of Congo, Egypt, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Mauritius, Morocco, Mozambique, Namibia, Niger, Nigeria, Senegal, South Africa, South Sudan, Sudan, United Republic of Tanzania, Togo, Tunisia, Zambia, Zimbabwe and other African countries and territories²⁹.

Caspian: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyz Republic, Tajikistan, Turkmenistan and Uzbekistan.

²⁶ Note by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

²⁷ Individual data are not available and are estimated in aggregate for: Burkina Faso, Burundi, Cabo Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Réunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland, Uganda and Western Sahara.

²⁸ Individual data are not available and are estimated in aggregate for: Afghanistan, Bhutan, Cook Islands, Fiji, French Polynesia, Kiribati, the Lao People's Democratic Republic, Macau (China), Maldives, New Caledonia, Palau, Papua New Guinea, Samoa, Solomon Islands, Timor-Leste and Tonga and Vanuatu.

²⁹ Individual data are not available and are estimated in aggregate for: Burkina Faso, Burundi, Cape Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Reunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland, Uganda and Western Sahara.

China: Refers to the People's Republic of China, including Hong Kong.

Developing countries: Non-OECD Asia, Middle East, Africa and Latin America regional groupings.

Eastern Europe/Eurasia: Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Georgia, Kazakhstan, Kosovo, Kyrgyz Republic, Lithuania, the former Yugoslav Republic of Macedonia, the Republic of Moldova, Montenegro, Romania, Russian Federation, Serbia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan. For statistical reasons, this region also includes Cyprus^{30,31}, Gibraltar and Malta.

European Union: Austria, Belgium, Bulgaria, Croatia, Cyprus^{2,3}, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovak Republic, Slovenia, Spain, Sweden and United Kingdom.

G-20: Argentina, Australia, Brazil, Canada, China, France, Germany, India, Indonesia, Italy, Japan, Mexico, Russian Federation, Saudi Arabia, South Africa, Korea, Turkey, United Kingdom, United States and the European Union.

Latin America: Argentina, Bolivia, Brazil, Colombia, Costa Rica, Cuba, Curaçao, Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Nicaragua, Panama, Paraguay, Peru, Trinidad and Tobago, Uruguay, Venezuela and other non-OECD Americas countries and territories.³²

Middle East: Bahrain, the Islamic Republic of Iran, Iraq, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic, United Arab Emirates and Yemen.

Non-OECD Asia: Bangladesh, Brunei Darussalam, Cambodia, China, Chinese Taipei, India, Indonesia, the Democratic People's Republic of Korea, Malaysia, Mongolia, Myanmar, Nepal, Pakistan, the Philippines, Singapore, Sri Lanka, Thailand, Viet Nam and other Asian countries and territories.³³

North Africa: Algeria, Egypt, Libya, Morocco and Tunisia.

OECD: Includes OECD Americas, OECD Asia Oceania and OECD Europe regional groupings.

OECD Americas: Canada, Chile, Mexico and the United States.

OECD Asia Oceania: Australia, Japan, Korea and New Zealand.

OECD Europe: Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Latvia, Luxembourg, Netherlands, Norway, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and United Kingdom. For statistical reasons, this region also includes Israel.³⁴

³⁰ Note by Turkey: The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of United Nations, Turkey shall preserve its position concerning the "Cyprus issue".

³¹ Note by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

³² Individual data are not available and are estimated in aggregate for: Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, Bonaire, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), French Guyana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, Saba, Saint Eustatius, St. Kitts & Nevis, St. Lucia, St. Vincent and the Grenadines, Saint Maarten, Suriname, Turks & Caicos Islands.

³³ Individual data are not available and are estimated in aggregate for: Afghanistan, Bhutan, Cook Islands, Fiji, French Polynesia, Kiribati, Lao PDR, Macau (China), Maldives, New Caledonia, Palau, Papua New Guinea, Samoa, Solomon Islands, Timor-Leste and Tonga and Vanuatu.

³⁴ The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

Organization of Petroleum Exporting Countries (OPEC): Algeria, Angola, Ecuador, the Islamic Republic of Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates and Venezuela. Indonesia is included among non-OPEC countries in this *WEO*, as it has not formally re-joined OPEC at the time of publication.

Southeast Asia: Brunei Darussalam, Cambodia, Indonesia, Lao PDR, Malaysia, Myanmar, Philippines, Singapore, Thailand and Viet Nam. These countries are all members of the Association of Southeast Asian Nations (ASEAN).

Sub-Saharan Africa: Africa regional grouping excluding the North Africa regional grouping.

A1.3 Oil and natural gas supply modules

The *WEM* oil and gas supply modules are made up of 120 regional models of which 101 countries have production levels modelled on an individual basis. Trade volumes broken down by pipeline and liquefied natural gas are modelled only for the following 20 areas: Canada, Mexico, United States, Brazil, Other Latin America, European Union, Other OECD Europe, Other Eastern Europe, North Africa, West Africa, East Africa, Russia, Caspian, Middle East, OECD Asia, OECD Oceania, China, India, Southeast Asia, and Other Asia. The 101 countries for which oil and gas production levels are modelled individually can be categorised into the 20 gas trade modelling areas in the following manner:

Canada: Canada.

Mexico: Mexico.

United States: United States.

Brazil: Brazil.

Other Latin America: Argentina, Bolivia, Chile, Colombia, Cuba, Ecuador, Paraguay, Peru, Trinidad and Tobago, Uruguay, and Venezuela.

European Union: Denmark, Estonia, France, Germany, Greenland, Italy, Netherlands, Poland, Romania, Slovenia, Sweden, and United Kingdom.

Other OECD Europe: Israel (included in this region for statistical reasons) and Norway.

Other Eastern Europe: Ukraine.

North Africa: Algeria, Libya, Egypt, Tunisia, and Morocco.

West Africa: Angola, Benin, Cameroon, Central African Republic, Chad, Congo, Democratic Republic of Congo, Equatorial Guinea, Gabon, Gambia, Ghana, Guinea, Guinea Bissau, Ivory Coast, Liberia, Mauritania, Niger, Nigeria, Senegal, Sierra Leone, and Togo.

East Africa: Botswana, Eritrea, Ethiopia, Kenya, Madagascar, Mozambique, Namibia, Seychelles, Somalia, South Africa, South Sudan, Sudan, Tanzania, and Uganda.

Russia: Russia.

Caspian: Azerbaijan, Kazakhstan, Turkmenistan, and Uzbekistan.

Middle East: Bahrain, Iran, Iraq, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, United Arab Emirates, and Yemen. Data for Saudi Arabia and Kuwait include 50% each of production from the Neutral Zone.

OECD Asia: Japan and Korea.

OECD Oceania: Australia and New Zealand.

China: China.

India: India.

Southeast Asia: Brunei Darussalam, Indonesia, Malaysia, Philippines, Thailand, and Viet Nam.

Other Asia: Bangladesh and Pakistan.

A1.4 Coal supply module

19 countries are modelled on an individual basis in the WEM coal supply module: Australia, Brazil, Canada, Chile, China, Colombia, India, Indonesia, Japan, Korea, Mexico, Mongolia, Mozambique, New Zealand, Russia, South Africa, the United States, Venezuela and Viet Nam.

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