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Representing the costs of low-carbon power generation in multi-region multi-sector energy-economic models

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ABSTRACT

Multi-region multi-sector energy-economic models are often used to analyze long-term scenarios of energy development, however, these models usually rely on a simplified representation of technological details in power generation. To strengthen this representation, we develop a method for modeling the economic competition between different advanced technologies in multi-region multi-sector dynamic energy-economic models based on a markup approach, which represents the measure of the cost of a technology relative to the price received for electricity generation. The markup includes capital costs, fixed and variable operating and maintenance (O&M) costs, fuel costs, and transmission and distribution (T&D) costs. For intermittent technologies, it also includes a backup requirement to make these technologies effectively dispatchable. For carbon capture and storage (CCS) technologies, it also includes the costs of CO_2 capture, transportation and storage. We provide a standardized markup calculation for generation technologies for different regions of the world, including USA, China, India, EU, Japan and others. Then we analyze the sensitivity of the calculation to critical inputs, including capital costs, fuel costs, carbon prices and capacity factors. We provide a detailed calculation of the relative costs of the following technologies: new pulverized coal, new pulverized coal with CCS, natural gas combined cycle, natural gas with CCS, biomass-fueled plant, biomass with CCS, advanced nuclear, wind (for small and medium penetration levels), solar, wind with backup (for large penetration levels), co-firing of coal and biomass combined with CCS, and advanced CCS on natural gas. For illustration, we incorporate the markups into the MIT Economic Projection and Policy Analysis (EPPA) model, a global multi-sector multi-sector dynamic energy-economic model with a detailed representation of power generation technologies, and run several scenarios. Our analysis and results provide insight on the deployment of different low-carbon power generation technologies depending on assumptions about carbon policy stringency.

1. Introduction

Global CO_2 emissions from power generation contributed more than 40% to the total energy-related CO_2 emissions in 2015 (IEA, 2017). Most projections envision that emission reductions from the electricity sector will occur earlier than in other sectors of the economy due to the availability of lower-carbon options, such as wind, solar, biomass, hydro, nuclear, and carbon capture and storage (CCS) (IPCC, 2014). Energy-economic models of various scopes are often used to analyze long-term scenarios of energy development for different policy proposals to reduce greenhouse gas emissions, support renewable generation, introduce taxes or remove subsidies, retire certain technologies, and other applications. Many of these models are used as a component of Integrated Assessment Models (IAMs) or coupled human-earth systems models, which are designed for century-long projections.

A challenging task for long-term electricity projections is capturing the fundamental technical and economic implications of the competition between generation technologies. One important issue is the intermittency of renewables in situations where the currently-existing dispatchable capacity retires and is no longer available. One potential solution for improving forecasts lies in using more detailed electricity models, such as hybrid capacity expansion-dispatch models, and different frameworks for combining economy-wide models with detailed electricity models exist. However, these detailed models are available only for a limited set of countries (e.g., USA, Spain, UK) or regions within a country, which makes their application to global or multi-

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region projections problematic.

At the same time, multi-region, multi-sector dynamic energy-economic models, such as computable general equilibrium (CGE) models, are valuable tools that can capture important interactions between multiple sectors and regions. For example, such models can capture how increased shale gas production in the U.S. lowers the price of natural gas, which lowers the cost of gas-based generation, which can lower the price of electricity, which can in turn increase demand for electricity. They can also capture international trade dynamics, for example, how a decrease in the supply of natural gas in Russia could affect prices in Europe, or how increased production of biocrops in Brazil could decrease the cost of bioelectricity in other regions. In CGE models, supply, demand and all prices are determined endogenously in the model. However, such a wide scope of coverage requires aggregated representation of regions, sectors and technologies. Most of these models approximate the major dynamics related to the competition between different power generation technologies by representing technological details in power generation in an aggregated fashion.

This paper provides a simple but instructive method for modeling the change in competiveness of different electricity technologies, including a range of CCS technologies, in multi-region multi-sector dynamic energy-economic models. Many of these models rely on a simple levelized cost of electricity (LCOE) calculation, which does not differentiate between baseload (or dispatchable) and intermittent power sources, causing the practical value of baseload or dispatchable energy for power distributers to be underestimated.

We propose a *markup* approach that provides a basis for modeling the economic competition between new plants with different technologies. The markup represents the measure of the cost of a technology in a specific year relative to the price received for electricity generation in that year. If the markup is greater than one, then technology is not economic unless it is supported by other means (subsidies, standards, requirements, etc.). The markup is calculated based on capital costs, fixed and variable operating and maintenance (O&M) costs, fuel costs, and transmission and distribution (T&D) costs. For systems with a high penetration of intermittent renewable technologies, it also includes a backup requirement to make those technologies effectively dispatchable. For technologies that include CCS, it also contains carbon dioxide capture, transportation and storage cost components. The markups reflect the cost of new construction. For plants that have already been built and are in operation, the O&M and fuel costs are the primary drivers of energy generation. For new plants, the full costs – including the cost of construction – need to be considered.

We provide a range of *markup* calculations for generation technologies for different regions of the world, including USA, China, India, EU, Japan and others. Then we analyze the sensitivity of the calculation to inputs of capital costs, fuel costs, carbon prices, capacity factors, backup requirements for intermittent renewables, and project economic lifetimes. We provide a detailed calculation of the relative costs of several technologies: new pulverized coal, new pulverized coal with CCS, natural gas combined cycle, natural gas with CCS, biomass-fueled plant, biomass with CCS, advanced nuclear, solar, wind without backup (for lower penetration levels), wind with backup (for higher penetration levels), co-firing of coal and biomass combined with CCS, and advanced CCS on natural gas. The approach can be similarly applied to additional technologies not included here. For illustration, we use the MIT Economic Projection and Policy Analysis (EPPA) model (Chen et al., 2016), which is a global multi-region multi-sector energy-economic model with an explicit representation of power generation technologies. Our approach can also be used for other models of similar types and structures, including those representing multiple regions within a single country (such as U.S.A. states or Chinese provinces). Our analysis provides insight on the deployment of different low-carbon power generation technologies, depending on assumptions about carbon policy stringency.

The paper is organized in the following way. In Section 2 we detail our method of calculating the LCOE and markups. In Section 3 we investigate regional differences in the LCOE and markup calculation. In Section 4 we conduct a sensitivity analysis of the markup calculations, and in Section 5 we test various scenarios in the EPPA model to determine the mix of various power generation technologies over time. In Section 6 we offer some conclusions.

2. Relative costs of power generation technologies

The metric of the levelized cost of electricity (LCOE) is often used to compare the costs of different electricity generation technologies.[1] LCOE calculates a single price of electricity per kilowatt-hour that should be sustained over the project economic life for the owner to recover all expenses, including capital, operating, and maintenance costs, as well as interest charges and returns on equity. Sometimes the LCOE is referred to as the “break-even” electricity price.

The costs for the LCOE calculation can be divided into three main categories: capital costs, operating and maintenance (O&M) costs, and fuel costs. Capital costs, which we to refer to as the “Total Capital Requirement,” consist of the overnight capital costs plus the interest and escalation during construction. The overnight cost is the cost of building the power plant as if the developer pays the entire cost up front (i.e., “overnight”). It includes equipment, supporting facilities, and labor (the bare erected costs), costs for engineering services and contingencies, and owner’s costs, including feasibility studies, surveys, land, insurance, permitting, and financial transaction costs, among others.

In actuality, the entire project cost is not paid in one sum up front, but instead the developer pays along the way during the construction phase of the project. This results in interest charges during construction and at times increasing costs. For certain technologies, there are also costs that are incurred at the end of the life of the project. For example, in the case of a nuclear power plant, the total capital requirement also includes the decommissioning cost that must be paid at the end of the plant’s life. Since LCOE is a “busbar” cost, the total capital requirement does not include transmission and distribution costs.

O&M costs are those required to run the plant on a daily basis. They are divided into fixed and variable costs depending on whether they are independent from or dependent on the quantity of energy produced. Fuel cost is the cost of purchasing the fuel used to operate the plant. In addition to cost data, the LCOE calculation requires additional inputs, including a capacity factor, project economic life, heat rate, and return rate on capital. We discuss these inputs below.

The capacity factor is the ratio of the actual output of a plant over a period of time to its output had it operated at full capacity over that time. It is expressed as a percent and is highly dependent on the type of power plant. The capacity factor is used to determine the total number of operating hours in a year, which is calculated by multiplying the number of hours in a year (8760 hours) by the capacity factor. The project economic life[2] is the number of years over which the plant will be amortized. Note that most plants actually operate longer than the project economic life. Heat rate is a measure of the plant’s thermal efficiency. It is the ratio of the heat content of the fuels fed into the plant expressed in megajoules (MJ or one million joules) divided by the net electricity output expressed in kilowatt-hours (kWh). The fuel cost in $/kWh is equal to the fuel cost given in $/GJ multiplied by the heat rate and divided by 1000.

[1] The LCOE is also known as the “busbar cost” because it represents the cost of the electricity production up to the power plant’s busbar, which is an equipment that links the plant’s generators to the transmission equipment that delivers electricity to the consumer.

[2] Sometimes “project economic life” is referred to as “project financial life” (EIA, 2017a,b).

There are several rates[3] related to a rate of return on capital. There is a risk-free rate of return (also sometimes called an interest rate or discount rate), which is a rate for a zero-risk investment. In practice, the risk-free rate does not exist because any investment has some risk. The interest rate on the U.S. Treasury bills is often used as the risk-free rate indicator. The project cost of capital is a combination of debt (borrowing) and equity (investment) used to finance a plant. The weighted cost of capital is a weighted average of the interest rate on the debt and the rate of return on the equity. The project economic life and the weighted cost of capital are used to calculate the capital recovery charge (CRC) rate. The CRC is the rate that gives the constant capital recovery necessary each year over the life of the plant in order to recover capital costs. The CRC is calculated as follows:

$$CRC = \frac{r}{1-(1+r)^{-n}} \tag{1}$$

where r is the weighted cost of capital and n is the number of years of the project economic life (Bodansky, 2004).

The resulting formula to calculate the LCOE in \$/kWh is:

$$LCOE = \frac{TCR*CRC}{OH} + \frac{FOM}{OH} + VOM + FC \tag{2}$$

where:

TCR is total capital requirement (\$/kW),
CRC is capital recovery charge (%/year),
OH is operating hours (hours/year),
FOM is fixed O&M (\$/kW/year),
VOM is variable O&M (\$/kWh), and
FC is fuel cost (\$/kWh).

The LCOE approach has gained popularity (EIA, 2016; IEA, 2015) because of its simplicity. Despite numerous critical publications (Joskow, 2011; EPRI, 2015), LCOE remains a popular and convenient way to compare the cost of generating technologies on a common basis of dollars per kilowatt hour (\$/kWh).

The criticisms of LCOE stem primarily from its failure to differentiate between baseload or dispatchable generation and intermittent power sources, causing the practical value of baseload and dispatchable energy for power distributers to be underestimated. In turn, the value of intermittent resources is overestimated if costs related to integrating such resources into the system are not included. The timing and location of the supply of the intermittent resource may be ill-matched with demand. This can result in the need for other dispatchable generation to be ready in case the renewable resource is not available. It can also result in curtailment or spillage, where potential power generation from the renewable source is simply not used because of a lack of consumer demand (or lack of transmission capacity to connect to other demand areas). The EIA also notes that LCOE calculations are not able to gauge the true projected utilization rate of a plant, which "depends on the load shape and existing resource mix in an area" (EIA, 2016). Regardless of the limitations of LCOE calculations, it is still generally seen as a "convenient summary measure of the overall competitiveness of different generating technologies" (EIA, 2016).

In order to improve the relative cost estimates for an intermittent technology, our *markup* method considers two types of intermittent technologies: non-dispatchable (at small shares of the generation mix in a region, typically up to 20–30% of the total generation) and "dispatchable"—those that are accompanied by backup generation capacity, which enables them to achieve higher levels of penetration.[4] While we assume backup capacity to make renewables "dispatchable", an alternative assumption is energy storage (such as pumped hydro or battery storage). While we do not include energy storage in the set of technologies to which we apply our markup approach in this paper (due to their high costs and the limited storage duration of, for example, batteries), the approach is applicable to such technologies.

To make renewable generation comparable to dispatchable generation, a requirement of backup capacity that is available for the periods when "the wind is not blowing or the sun is not shining" can be introduced to markup calculations. However, quantification of how much backup capacity is needed requires a very detailed electricity model resolved at short time scales (an hour or less) that matches the renewable resource's variability with demand, which also varies by season and time of day. Such detailed electricity models that properly account for intermittency at different levels of penetration do not exist for many regions of the world. In those cases where such models exist, they are not in the public domain and many researchers and analysts do not have access to these detailed models.

An upper bound for backup capacity can be estimated as a 1-for-1 ratio, i.e., a power system has to have one unit of dispatchable capacity (e.g. 1 megawatt, MW) for each unit of intermittent capacity. The 1-for-1 assumption is quite strong, but it may be relevant for high penetration levels of renewables. Gunturu and Schlosser (2015) demonstrated for the U.S. that there are significant periods of time when little wind power is available throughout the continental U.S. Evidence of strong correlation of wind availability across regions of the continental U.S. suggests that transmission may only be able to marginally improve the situation. Cosseron et al. (2013) found a similar result for Europe. A system that heavily relies on renewables, will require backup for all of the renewable capacity for the times when virtually none is available. An assumption about backup capacity required for renewable generation added to the LCOE and markup calculation allows our approach to more accurately compare the relative costs of different technologies in different parts of the world—which is needed for multi-region multi-sector dynamic energy economic models.

3. Calculating lcoe and markups for different regions

3.1. LCOE and markup values for USA

In this section we start with an example of the LCOE and the resulting markup calculations for USA. We then show the regional variation in the markups. While we show the markup calculations for a particular year (2015 in our example), in energy-economic models the prices of all inputs to power generation change from time-period to time-period. Based on new prices, the resulting markups will be determined by the model depending on the new economic conditions. These new relative costs will determine the economic competitiveness and deployment of different technologies. Energy-economic models use a particular year (called a base year) as a starting year for which input data is collected. Our calculations for 2015 can be converted into the values for the base year of a given model.[5]

The markup is the measure of the cost of a technology (including transmission and distribution costs as well as backup costs for intermittent technologies and carbon dioxide transportation and storage cost components for CCS technologies) relative to the average wholesale electricity price. To represent the cost to society as opposed to the cost paid by the project developer, the markup does not include government interventions, such as subsidies, renewable portfolio standards or feed-in tariffs. In order for the costs of such policies to be captured, these interventions should be explicitly represented in the model rather than in the markups.

[3] Different terms for interest rates are used in literature. We categorize three different rates as a discount rate (or risk-free rate), a project interest rate (or cost of capital), and a capital recovery charge rate. See text for further discussion.

[4] In economy-wide models, non-dispatchable technologies can be represented as imperfect substitutes to dispatchable technologies (which, in turn, can be represented as perfect substitutes that produce a homogenous output).

[5] In the version of the EPPA model that we will use later for illustration, the base year is 2007 and the values in the model are converted accordingly.

Table 1
Markup Calculation for USA for established power generation technologies (in 2015$).

		Units	Coal	Gas	Biomass	Wind	Solar	Nuclear
[1]	"Overnight" Capital Cost	$/kW	2148	1031	4181	1845	1581	4286
[2]	SCALED Overnight Capital Cost	$/kW	2365	1135	4602	2031	1740	4718
[3]	**Total Capital Requirement**	$/kW	**2743**	**1226**	**5339**	**2194**	**1879**	**6133**
[4]	Capital Recovery Charge Rate	%	10.6%	10.6%	10.6%	10.6%	10.6%	10.6%
[5]	Fixed O&M	$/kW/year	39	30	109	50	26	71
[6]	Variable O&M	$/kWh	0.0035	0.0028	0.0054	0.0147	0.0168	0.0035
[7]	Project Life	years	20	20	20	20	20	20
[8]	Capacity Factor	%	85%	85%	80%	35%	20%	85%
[9]	(Capacity Factor Wind)							
[10]	(Capacity Factor Biomass/NGCC)							
[11]	Operating Hours	hours/year	7446	7446	7008	3066	1752	7446
[12]	Capital Recovery Required	$/kWh	0.0389	0.0174	0.0805	0.0756	0.1133	0.0870
[13]	Fixed O&M Recovery Required	$/kWh	0.0052	0.0041	0.0155	0.0165	0.0146	0.0095
[14]	Efficiency, HHV	%	42%	53%	30%			33%
[15]	Heat Rate, HHV	MJ/kWh	8.63	6.76	12.00	0	0	11.06
[16]	Fuel Cost	$/GJ	2.08	4.16	3.14	0.00	0.00	0.87
[17]	Fuel Cost per kWh	$/kWh	0.0179	0.0281	0.0377	0.0000	0.0000	0.0096
[18]	**Levelized Cost of Electricity**	$/kWh	**0.0656**	**0.0523**	**0.1391**	**0.1068**	**0.1447**	**0.1097**
[19]	Transmission and Distribution	$/kWh	0.03	0.03	0.03	0.03	0.03	0.03
[20]	**Levelized Cost of Electricity incl. T&D**	$/kWh	**0.0956**	**0.0823**	**0.1691**	**0.1368**	**0.1747**	**0.1397**
[21]	EPPA Base Year Elec Price	$/kWh	0.0924	0.0924	0.0924	0.0924	0.0924	0.0924
[22]	**Markup Over Base Elec Price**		**1.03**	**0.89**	**1.83**	**1.48**	**1.89**	**1.51**

The markup calculation for USA is shown in Table 1 for more established technologies: new pulverized coal (denoted thereafter as "Coal"), natural gas combined cycle ("*Gas*"), biomass-fueled plant ("*Biomass*"), onshore wind for small and medium penetration levels ("*Wind*"), solar photovoltaic ("*Solar*") and advanced nuclear ("*Nuclear*"). *Wind* and *Solar* are non-dispatchable technologies (i.e. they are not accompanied by back-up capacity) and can therefore contribute only a limited share to the total generation mix.

Table 2 shows the corresponding calculations for advanced technologies: new pulverized coal with carbon capture and storage ("*Coal with CCS*"), natural gas with CCS ("*Gas with CCS*"), biomass with CCS ("*BECCS*"), co-firing of coal and biomass combined with CCS ("*Coal + Bio CCS*"), advanced CCS on natural gas ("*Gas with Advanced CCS*"), wind (for large penetration levels) with natural gas turbine-based backup ("*WindGas*"), and wind (for large penetration levels) with biomass -based backup ("*WindBio*"). The *Coal + Bio CCS* technology assumes that coal is co-fired with 7.6% biomass (on a heat input basis), which is the amount of biomass calculated as necessary to offset the uncaptured coal emissions and therefore make the technology have net zero emissions. The gas with advanced CCS technology assumes 100% of CO_2 emissions are captured at low cost. This technology is at an early stage of development, and we base our representation on the NET

Table 2
Markup Calculation for USA for advanced power generation technologies (in 2015$).

		Units	Coal with CCS	Gas with CCS	BECCS	Coal + Bio CCS	Gas with Advanced CCS	WindGas	WindBio
[1]	"Overnight" Capital Cost	$/kW	4100		8867			2536	6026
[2]	SCALED Overnight Capital Cost	$/kW	4514		9762			2792	6634
[3]	**Total Capital Requirement**	$/kW	**5417**	**2336**	**11714**	**5630**	**1431**	**3015**	**7165**
[4]	Capital Recovery Charge Rate	%	10.6%	10.6%	10.6%	10.6%	10.6%	10.6%	10.6%
[5]	Fixed O&M	$/kW/year	62	59	169	78	35	58	159
[6]	Variable O&M	$/kWh	0.0057	0.0065	0.0087	0.0057	0.0028	0.0141	0.0132
[7]	Project Life	years	20	20	20	20	20	20	20
[8]	Capacity Factor	%	85%	85%	80%	85%	85%	42%	42%
[9]	(Capacity Factor Wind)							35%	35%
[10]	(Capacity Factor Biomass/NGCC)							7%	7%
[11]	Operating Hours	hours/year	7446	7446	7008	7446	7446	3679.2	3679.2
[12]	Capital Recovery Required	$/kWh	0.0769	0.0332	0.1766	0.0799	0.0203	0.0866	0.2058
[13]	Fixed O&M Recovery Required	$/kWh	0.0084	0.0079	0.0242	0.0104	0.0048	0.0157	0.0433
[14]	Efficiency, HHV	%	33%	45%	21%	32%	53%	40%	30%
[15]	Heat Rate, HHV	MJ/kWh	10.92	8.02	17.35	11.14	6.77	9.02	12.00
[16]	Fuel Cost	$/GJ	2.08	4.16	3.14	2.08	4.16	4.16	3.14
[17]	Fuel Cost per kWh	$/kWh	0.0227	0.0333	0.0544	0.0243	0.0281	0.0031	0.0033
[18]	**Levelized Cost of Electricity**	$/kWh	**0.1230**	**0.0845**	**0.2783**	**0.1298**	**0.0594**	**0.1194**	**0.2655**
[19]	Transmission and Distribution	$/kWh	0.03	0.03	0.03	0.03	0.03	0.04	0.04
[20]	**Levelized Cost of Electricity incl. T&D**	$/kWh	**0.15**	**0.11**	**0.31**	**0.16**	**0.09**	**0.16**	**0.31**
[21]	EPPA Base Year Elec Price	$/kWh	0.09	0.09	0.09	0.09	0.09	0.09	0.09
[22]	**Markup Over Base Elec Price**		**1.66**	**1.24**	**3.34**	**1.73**	**0.97**	**1.73**	**3.31**
	For CCS								
[23]	Carbon Content	kgC/GJ	24.686	13.700	24.975	24.686	13.700		
[24]	Carbon Emissions	kgC/kWh	0.2696	0.1098	0.4333	0.2750	0.0928		
[25]	Carbon Dioxide Emissions	kgCO2/kWh	0.9886	0.4027	1.5887	1.0082	0.3401		
[26]	Percent Emissions Captured	%	95%	90%	90%	95%	100%		
[27]	CO2 Emissions Captured	kgCO2/kWh	0.9392	0.3624	1.4298	0.9578	0.3401		
[28]	Cost of CO2 T&S	$/tCO2	10	10	10	10	10		
[29]	CO2 Transportation and Storage Cost	$/kWh	0.0094	0.0036	0.0143	0.0096	0.0034		

Table 3
Regional variation in prices and capital scalars.

	Electricity $/kWh	Coal $/GJ	Gas $/GJ	Biomass $/GJ	Capital Scalar
AFR	0.064	1.26	4.31	2.70	0.58
ANZ	0.101	2.38	5.32	2.75	1.21
ASI	0.078	2.35	6.17	3.08	0.42
BRA	0.106	2.85	3.79	2.53	1.09
CAN	0.073	1.98	5.17	2.72	1.44
CHN	0.051	1.51	6.96	3.79	0.33
EUR	0.139	2.61	7.11	3.03	1.42
IDZ	0.073	1.71	4.39	3.08	0.33
IND	0.089	1.33	6.04	5.75	0.79
JPN	0.146	2.64	6.76	10.29	1.23
KOR	0.080	2.41	8.22	3.08	0.62
LAM	0.090	2.44	1.88	2.70	1.09
MES	0.089	2.43	3.39	4.38	0.33
MEX	0.096	2.25	5.72	3.55	0.44
REA	0.106	2.16	5.19	3.53	0.87
ROE	0.092	2.47	6.11	3.25	0.67
RUS	0.032	1.59	4.21	2.68	0.33
USA	0.090	2.02	4.04	3.05	1.10

Note: Regional prices are based on the GTAP 9 database (Aguiar et al., 2016).

Power technology.[6] *WindGas* and *WindBio* are wind with either a gas turbine or a biomass-based backup with the default assumption that 1-for-1 backup capacity is required.

The relative value of an amount of money in one year is different when compared to another year (e.g., one tonne of coal will have a different cost when measured in 2005 dollars versus in 2015 dollars), therefore, it is important to represent the monetary values in the same units. While most of the cost data are from 2015 and 2017, all values in Tables 1 and 2 (and subsequent tables) are reported in 2015 U.S. dollars (USD).

We base our input cost values on IEA (2015) when possible. IEA (2015) provides a median, minimum and maximum globally averaged value for key cost inputs. We use the median values for our base markups, but also use the minimum and maximum values to provide a range of markup values (see Section 3.2 and Appendix C). For inputs that IEA does not provide, we rely on other sources (Tables A1 and A2 in Appendix A provide a full list of data sources). Regional capital scalars, along with regional fuel and electricity prices are used to make the calculations region-specific. We also assume the markups are for the Nth-of-a-kind for each technology. To explain in detail how the markups in Tables 1 and 2 are calculated, we use the column labeled "Coal" in Table 1 to illustrate.

Row [1]. According to IEA (2015), the overnight capital cost of building a new coal-based power plant is $2148/kW[7] (entered in row [1], Table 1). This IEA number is a globally averaged cost.

Row [2]. The globally averaged overnight capital cost is multiplied by a capital scaling factor to obtain the overnight capital costs for the USA, which appears in row [2]. Capital scaling factors (or capital scalars) are obtained based on the relative cost of capital in electricity in a particular region to the globally averaged capital cost for the plants represented in IEA (2015) data. The regional cost of capital is from GTAP dataset (Aguiar et al., 2016). For USA, the scaling factor is 1.1. A full list of capital scaling factors is reported in Table 3.

Row [3]. The scaled overnight cost is multiplied by a factor of (1 + 0.04*construction time in years) to obtain the total capital requirement appearing in row [3].[8] Based on the assumed 4-year construction period for a coal power plant, the scaled overnight cost is multiplied by a factor of 1.16.

Row [4]. The cost of capital is taken to be 8.5%. Following EIA (2017a,b), we use a 20-year project economic life for all types of plants (row [7]). This results in a capital recovery charge of 10.6%.

Rows [5-6]. Both the fixed and variable O&M costs for coal are from IEA (2015), with costs of $39/kW/year and $0.0035/kWh, respectively.

Row [7]. The project economic life is taken to be 20 years based on EIA (2017a,b).

Rows [8-11]. The capacity factor [8] for a new coal plant is assumed to be 85% based on IEA (2015), and from this, the total number of operational hours per year [11] is determined.[9]

Row [12]. In order to calculate the capital recovery required [12], the capital recovery charge rate [4] of 10.6% is multiplied by the total capital requirement [3]. This yields the total capital required per kilowatt per year, and by dividing by the total operating hours per year [11], the capital recovery in $/kWh [12] is obtained.

Row [13]. The fixed O&M recovery [13] is calculated by dividing the fixed O&M costs per year [5] by the total number of operational hours per year [11].

Rows [14-15]. The heat rate [15] is obtained from efficiency numbers [14] from IEA (2015), which is given on a low heating value (LHV) basis. We convert this to a high heating value (HHV) basis and report all efficiencies and heat rates in the Tables 1 and 2 on a HHV basis. They are 42% and 8.63 MJ/kWh for coal.

Rows [16-17]. The fuel costs [16] are from the GTAP database, and it is $2.02/GJ for coal. By multiplying the heat rate [15] and the fuel cost [16] (and dividing by 1000), the fuel cost per kWh [17] is found.

Rows [18-20]. The sum of the variable O&M [6], the capital recovery required [12], the fixed O&M required [13], and the fuel cost per kWh [17] yields the levelized cost of electricity [18] for technologies without CCS. For coal, the LCOE is $0.066/kWh. For a model like EPPA, total costs including transmission and distribution are required. Adding $0.03/kWh for transmission and distribution [19] for traditional technologies yields the levelized cost with transmission and distribution costs included [20]. That is $0.096/kWh for coal.

Rows [21-22]. Based on this information, the markup [22] is calculated for a particular region by dividing the levelized cost of electricity including transmission and distribution [20] by electricity price in that region [21] from GTAP. The markup then reflects the relative costs of all technologies in the base year of the EPPA model, which is the information the model needs to optimize electricity investment decisions. The markup for *Coal* is 1.03.

In addition to *Coal*, Table 1 also shows these calculations for *Gas*, *Biomass*, *Wind*, *Solar* and *Nuclear*, and Table 2 shows them for *Coal with CCS*, *Gas with CCS*, *BECCS*, *Coal + Bio CCS*, *Gas with Advanced CCS*, *WindGas* and *WindBio*.

Rows [23-29]. Plants with CCS have to account for the cost of transportation and storage of CO_2. The calculation is shown in lines [23] through [29] of Table 2. The amount of fossil fuel consumption comes from the heat rate [15]. That number is then multiplied by the

[6] https://www.netpower.com/

[7] All dollar values are in 2015 US$, unless stated otherwise.

[8] Construction time is assumed to be 2 years for Gas, Wind, Solar, WindGas and WindBio; 3 years for Gas with CCS and Gas with Advanced CCS; 4 years for Coal and Biomass; and 5 years for Coal with CCS, BECCS, Nuclear and Coal + Bio CCS.

[9] The markup is used to make decisions about new investments and we assume that a new coal or gas plant would be expected to operate closer to an 85% capacity factor rather than the existing fleet average capacity factor (which is closer to 55% for both coal and gas). Our model keeps track of older vintages of technologies, which effectively have declining capacity factors over time, driven by physical depreciation as well as competition from newer plants. Due to physical depreciation, less electricity is produced over time from the same plant, or else more capital needs to be invested into older plants to maintain output levels, which also effectively decreases the capacity factor. At the same time, older plants may become less competitive compared to newer, more efficient plants with lower operating costs, particularly under policies that put a price on carbon.

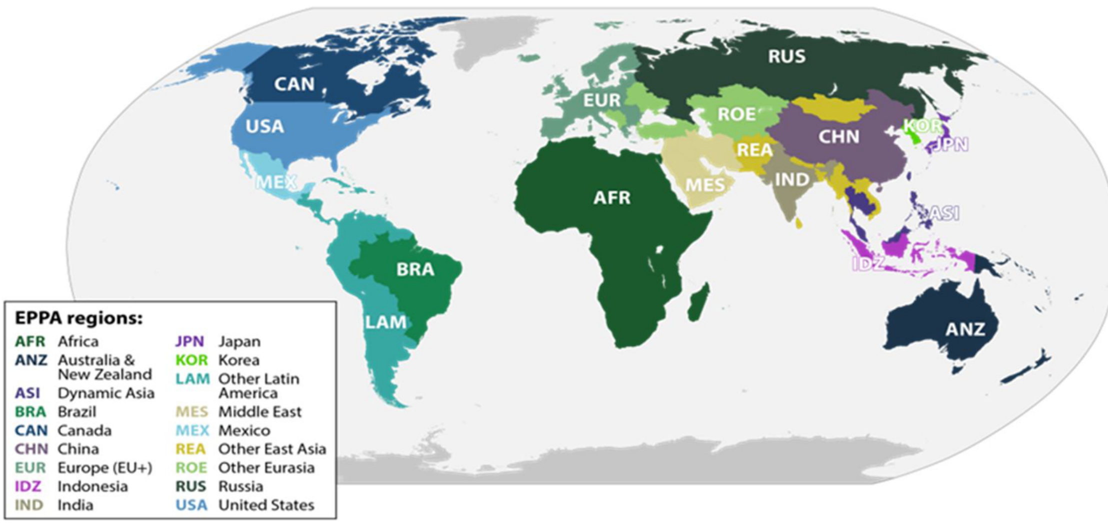

Fig. 1. Regional representation in the EPPA model.

carbon content [24] of the various fuel types, in kilograms of carbon per gigajoule (kgC/GJ), to give kgC per kWh [24]. The carbon content of each fossil fuel was retrieved from the US Environmental Protection Agency (EPA, 1998)[10] . Then, the carbon output per kWh of the technology [24] is converted to kg of CO_2 per kWh [25] by multiplying by the ratio of their molecular weights (44/12). An assumption of $10/$tCO_2$ for transportation and storage costs [28] is based on Rubin et al (2015). CO_2 transportation and storage cost is then multiplied by the amount of CO_2 emissions captured [27] to determine the cost of transportation and storage in $/kWh [29]. This value [29] is included in the levelized cost [18] for CCS technologies.

In order to incorporate the costs related to intermittency, we add backup capacity. We consider two technological options for the backup power– natural gas turbine[11] and biomass-based generation. The backup allows the combined technological option (intermittent generator and backup need not to be located together geographically) to be considered dispatchable. Given the finding by Gunturu and Schlosser (2015), we assume 1-for-1 backup, with the backup operating 7% of the time. Since the wind operates 35% of the time, this gives the wind power with backup a combined capacity factor of 42%. For the wind with backup technologies we take the overnight capital cost for wind and add to it either the overnight capital cost for a gas turbine or for a biomass plant. The corresponding procedure is done for fixed O&M. For variable O&M, we combine the wind variable O&M and the backup variable O&M based on the capacity factor of the respective technology relative to the combined capacity factor (e.g. 35/42 * wind variable O&M + 7/42 * backup variable O&M). We assume that wind with backup technologies require an additional $0.01/kWh in transmission and distribution costs compared to other technologies.[12]

In the United States, the lowest cost generation technology is *Gas* with a markup of 0.89. The low markup for *Gas* is due to its relatively low capital costs, short construction time, low fuel cost, and low fixed and variable O&M costs. The markup for wind generation (without any backup requirement) in USA is 1.48. At this markup, *Wind* would be competitive with nuclear, but more expensive than *Gas with CCS* technologies. However, at penetration levels requiring backup, the markup for *WindGas* rises to 1.73 and the markup for *WindBio* rises to 3.31, making *WindGas* competitive with *Coal with CCS*.

3.2. Regional LCOE and markup values

The same procedure is followed for each region of the world represented in the EPPA model (see Fig. 1, for the list of the regions). In each region, fuel costs and capital costs vary, as well as the average price of electricity (see Table 3).[13] The resulting markups that show the relative competitiveness of electricity generation technologies therefore also vary.

Fig. 2 compares the markups for a set of technologies in major regions of the world (see Appendix C for a full comparison of all technologies in all regions). The minimum and maximum markups are used to show a range of markup costs, with the median markups represented by the black lines. China, where electricity prices are low, tends to have higher markups than other regions across technologies. However, the low capital costs in China bring the markups for more capital-intensive technologies (like *Nuclear* and *Solar*) more on par with other regions. Regions with high electricity prices, like Japan and Europe, consistently have the lowest markups across technologies compared to other regions. It is easier for advanced technologies to compete in regions where the electricity price is already high. Differences in regional electricity prices underscore the caution when comparing the absolute values of LCOE or markups between different regions. Technologies with low LCOE may still be expensive compared the electricity price in the region.

4. Sensitivity of markup calculations to input parameters

To investigate the changes in the relative competitiveness of technologies, we perform a sensitivity analysis of the markup calculation with variations in capacity factors, carbon prices, project economic lifetimes, fuel costs, capital costs, and the amount of backup required for wind power. For each variation, we report the change in the 2015 markup relative to the base case input values. For example, with introduction of a carbon tax, CCS technologies become more competitive with both non-CCS fossil fuel technologies. The effects of sensitivity analyses on technologies vary by the sensitivity parameter, technology and region. We provide an example of calculations for USA. In Section 5

[10] The carbon content used for biomass comes from http://www.pfpi.net/carbon-emissions

[11] The backup assumes a natural gas turbine rather than a natural gas combined cycle plant. The costs for the gas turbine come from EIA (2017a,b).

[12] $0.04/kWh is used for wind with backup under the assumption that the best wind sites closest to demand have been used by the wind without backup and therefore the installments with backup are farther from demand and require additional transmission lines.

[13] We do not vary T&D costs by region due to the lack of data. We use the USA costs of $0.03/kWh for all regions.

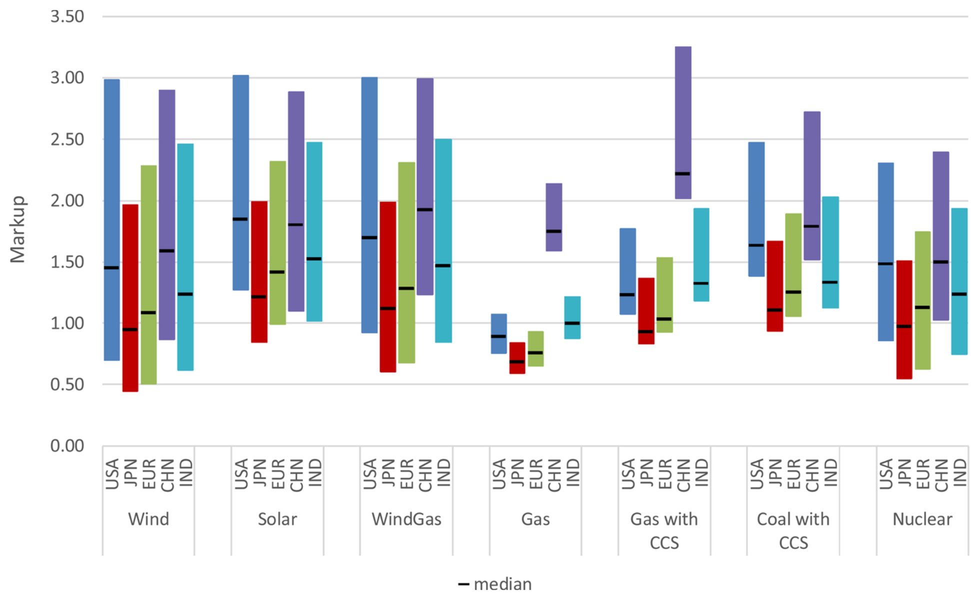

Fig. 2. Markup range and median for a set of technologies in major regions. The colored bars represent the range using min and max data from IEA (2015), with the black line representing the median, which is used as the base markup.

we provide the results for the global power generation mix up to 2100 with different assumptions about input values for the markups.

4.1. Capacity factors

The capacity factor is a ratio of the actual output of a power plant (in a certain period of time, typically in a year) as compared to its nameplate capacity. If there is maintenance at the plant, or the plant is not dispatched for other reasons, the capacity factor is reduced. In comparison to fossil-based and nuclear generation, *Solar* and *Wind* have low capacity factors due to inherent intermittencies in sunlight and wind. Fig. 3 shows the changes in markups when capacity factors are increased or decreased by 15%. Technologies with lower markups have smaller resulting changes in the markups. *Gas* and *Coal* markups are changing by 3-8%, while *BECCS* and *WindBio* markups are changing by 8-12%.

4.2. Carbon prices

By calculating the carbon content of each fuel and determining how much carbon is emitted per kilowatt-hour for each technology, a carbon fee (tax or price) scenario can be investigated to assess the changes in markups. We illustrate the changes for three different carbon prices: 30\$/tCO_2, 50\$/tCO_2, and 100\$/tCO_2. The markups in USA associated with varying carbon prices are shown in Table 4.

CCS technologies (except for a highly speculative advanced CCS) are not cost-competitive without a carbon price. Their markups are 20-80% higher than the markups for *Coal* and *Gas* technologies. With carbon pricing, the ranking of the lowest-cost technologies changes. *Coal* is the most sensitive to a change in carbon prices. The markup for *Coal* nears the markup for *Wind* with a carbon price of 50\$/tCO_2. With a carbon price of 100\$/tCO_2, the markup for *Coal* is almost the same as the markup for *Solar*. The fully-dispatchable *WindGas* becomes cheaper

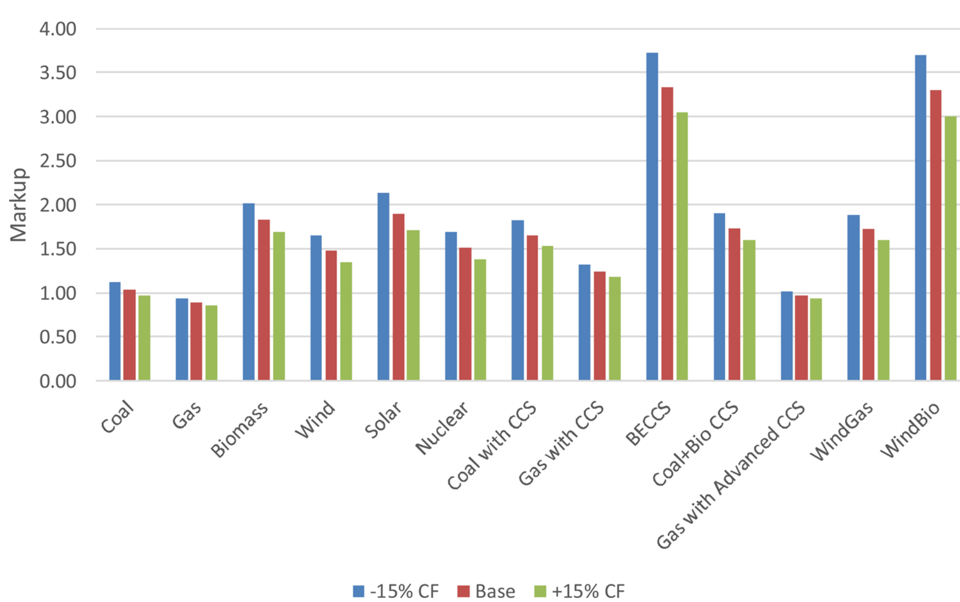

Fig. 3. Sensitivity of markups in USA to capacity factor assumptions.

Table 4
Sensitivity of markups to carbon price assumptions.

Technology	No Carbon Price	$30/ tCO2	$50/ tCO2	$100/tCO2
Coal	1.03	1.29	1.46	1.88
Gas	0.89	1.00	1.08	1.26
Biomass	1.83	1.87	1.89	1.95
Wind	1.48			
Solar	1.89			
Nuclear	1.51			
Coal with CCS	1.66	1.67	1.68	1.71
Gas with CCS	1.24	1.25	1.26	1.28
Coal + Bio CCS	1.73	1.75	1.76	1.78
Gas with Advanced CCS	0.97			
WindGas	1.73	1.75	1.77	1.81
WindBio	3.31	3.31	3.32	3.33

Table 5
Sensitivity of markups to project economic lifetime assumptions.

Technology	New Lifetime	Base Markup	New Markup
Coal	40	1.03	0.97
Gas	30	0.89	0.87
Biomass	30	1.83	1.73
Wind	25	1.48	1.42
Solar	25	1.89	1.80
Nuclear	60	1.51	1.33
Coal with CCS	40	1.66	1.52
Gas with CCS	30	1.24	1.20
BECCS	30	3.34	3.11
Coal + Bio CCS	40	1.73	1.59
Gas with Advanced CCS	30	0.97	0.94
WindGas	25	1.73	1.66
WindBio	25	3.31	3.14

than *Coal* when a carbon price approaches 100$/t$CO_2$. *Gas with Advanced CCS* becomes the lowest cost technology at a carbon price of 30$/t$CO_2$, as the cost of *Gas* increases with the carbon penalty. *Gas with Advanced CCS* captures 100% of emissions, therefore, its markup is not affected by the level of a carbon price, as is the case with other zero-carbon technologies like *Nuclear, Wind,* and *Solar*. We have not included *BECCS* in the carbon price variation because its markup depends on the treatment of carbon credits for its negative emissions.

4.3. Project economic life

In the base markup calculations, a 20-year project economic life is assumed for every technology based on EIA (2017a,b), which considers 20 years as a typical length of financing for the projects in power sector. Alternatively, if project developers are able to secure longer-term financing arrangements, longer project durations can be used for markup calculations. For an extended project life, an expected physical lifetime can be used. Table 5 shows the results of a sensitivity analysis for the USA with respect to project life variation.

As expected, when the project lifetime of power generation technology is increased, the markups are lower, as cost recovery can be spread over the longer period and less cost recovery is needed each year. The most significant markup decreases are for technologies with large capital requirements and for technologies for which the expected physical lifetime is much longer than a typical financial lifetime. Markups for *Coal*, *Nuclear*, *Coal with CCS*, *BECCS*, and *Coal + Bio CCS* are reduced by 7–12%. On the contrary, for technologies with relatively lower capital requirement, or physical lifetimes closer to the project economic life, change in a project lifetime does not result in substantial changes in their markups. The markup for *Gas*, *Wind*, *Gas with CCS*, *Gas with Advanced CCS* and *WindGas* only changes by 2–4%.

4.4. Fuel cost

In order to estimate the effect of varying fuel prices on the markup calculation, a sensitivity analysis is performed where fuel prices are varied by ± 50% from their base values reported in Table 3. The sensitivity of the markup to changes in fuel cost for the United States is shown in Fig. 4. Not surprisingly, *Gas* generation shows the largest relative sensitivity to a change in fuel prices (17–34% changes from base markups), as fuel is a substantial share of its total cost.

4.5. Capital costs

For many technologies, capital cost constitutes a substantial share of the total cost. We conduct a sensitivity analysis where the overnight capital cost for each technology is altered by ± 25%.[14] The markups for USA associated with varying capital costs are shown in Table 6.

The effects of increasing and decreasing the capital costs of various energy generation technologies vary based on the share of capital for each technology. For example, the markups for *Wind*, *Solar*, *Nuclear*, *BECCS, WindGas* and *WindBio* are increased by 14–17% with a 25% increase in the capital costs, while the markup for *Gas* is only increased by 5% and the markup for *Coal + Bio CCS* is increased by 28%.

4.6. Backup requirement

We also conduct a sensitivity analysis for how the markup of wind with backup generation varies when the one-for-one (100%) backup requirement is relaxed. In the base case, all costs of a natural gas turbine backup or biomass backup are added to the cost of the wind. We then determine the impact on markup for the wind with backup technologies when only 75%, 50%, and 25% of backup costs are required. By lowering the backup requirement, the total amount of overnight capital, fixed O&M, and variable O&M are lowered correspondingly. The markups for USA associated with varying backup requirements are shown in Table 7.

As expected, the markups are decreased with the lower backup requirement. Requiring less backup significantly lowers the markup for *WindBio,* as the costs of *Biomass* are large. With no backup, the markups for *WindGas* and *WindBio* are the same as for *Wind* (1.48).

4.7. Sensitivity analysis to input costs

Similar variations in input values as described in Sections 4.1–4.6 can be performed for all inputs for all technologies in all regions. Fig. 5 shows an example of such analysis for the changes in the markup values of *Gas with CCS* in USA, when the input values of capital cost, fixed O&M, variable O&M, capacity factor, fuel cost, CO_2 transportation and storage costs related to CCS (CCS T&S), and electricity transmission and distribution costs (Electricity T&D) are each varied in increments of 10%, ranging from a 50% reduction in the corresponding input value to a 50% increase in the corresponding input value. The value of 100% on the horizontal axis of Fig. 5 represents the base values for the inputs. At this level, the resulting markup is 1.24.

For *Gas with CCS*, fuel and capital cost affect the resulting markup in a similar way due to their relative shares in the total cost. The changes in fixed O&M, variable O&M, and CO_2 T&S have a similar linear relationship with the resulting markup changes. They do not substantially affect the markup as they constitute a small share in the total cost. Reductions in capacity factors can substantially increase the markup. Capacity factors have an upper bound (they cannot exceed 100%), therefore the corresponding line for an increase from the 100% value is shorter.

[14] For technologies in Table 2 that do not include overnight capital cost, the total capital requirement is varied by ± 25%.

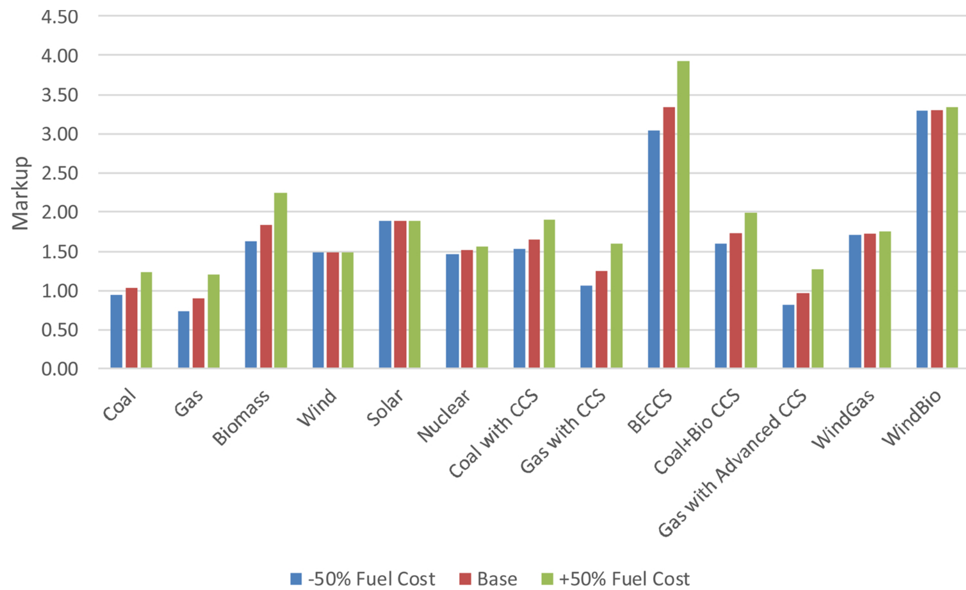

Fig. 4. Sensitivity of markups to fuel cost assumptions.

Table 6
Sensitivity of markups to capital cost assumptions.

	−25% Capital	Base Case	+25% Capital
Coal	0.93	1.03	1.14
Gas	0.84	0.89	0.94
Biomass	1.61	1.83	2.05
Wind	1.28	1.48	1.69
Solar	1.58	1.89	2.20
Nuclear	1.28	1.51	1.75
Coal with CCS	1.45	1.66	1.86
Gas with CCS	1.15	1.24	1.33
BECCS	2.86	3.34	3.82
Coal + Bio CCS	1.36	1.73	2.21
Gas with Advanced CCS	0.91	0.97	1.02
WindGas	1.49	1.73	1.96
WindBio	2.75	3.31	3.86

Table 7
Sensitivity of markups to backup requirement assumption.

Technology	Base Case	75% Backup	+50% Backup	+25% Backup
Coal	1.03			
Gas	0.89			
Biomass	1.83			
Wind	1.48			
Solar	1.89			
Nuclear	1.51			
Coal with CCS	1.66			
Gas with CCS	1.24			
BECCS	3.34			
Coal + Bio CCS	1.73			
Gas with Advanced CCS	0.97			
WindGas	1.73	1.70	1.66	1.63
WindBio	3.31	2.93	2.53	2.08

To provide an example of how the markups for different technologies are affected by a change in input values, we consider *Gas with CCS* and *Nuclear* technologies. The percent changes in the corresponding markups with a 10% increase and decrease in inputs are shown in Fig. 6. The largest changes in the markup occur with a 10% decrease in the capacity factor, which increases the markup by 3.8% for *Gas with CCS* and by 7.5% for *Nuclear*. Changes in capital cost also affect the resulting markup substantially. Because both *Gas with CCS* and *Nuclear* have relatively low fixed and variable O&M costs, increases in these inputs yielded minor changes in the corresponding markups. However, the technologies are affected differently by the changes in fuel prices. Because the fuel costs for *Gas with CCS* are more significant than fuel costs for *Nuclear*, the same percent changes in fuel costs affect the markup for *Gas with CCS* more than for *Nuclear*.

5. Policy and markup scenarios and the resulting technology mix

5.1. EPPA model

To illustrate the use of markups in multi-region multi-sector dynamic economy-wide models, we employ the MIT Economic Projection and Policy Analysis (EPPA) model (Paltsev et al., 2005, Chen et al., 2016). EPPA is a computable general equilibrium (CGE) model representing 18 regions and 16 sectors of the world economy, with additional detail in the electric power sector. For its base year (2007) data, the EPPA model uses the GTAP dataset (Narayanan et al., 2012), which provides a consistent representation of energy markets as well as detailed data on regional production, consumption, and bilateral trade flows. The model is calibrated to economic and energy data from IMF (2018) and IEA (2017) for 2010 and 2015 and then it solves in 5-year time steps from 2020 to 2100. Additional information about the version of the model that we use here can be found in Chen et al. (2016).

The EPPA model, like many multi-sector dynamic models, chooses the least-cost production opportunities based on market clearance conditions (supply must equal demand), normal profit conditions (the cost of inputs should not exceed the price of the output), and income balance conditions (expenditures must equal income, accounting for savings, subsidies and taxes). Production technologies are chosen based on their relative competitiveness. The EPPA model traces inter-industry and inter-regional connections, and changes in sectoral and regional prices over time affect the relative costs of technologies and the resulting technology mix.

To represent the initial cost of technologies, the information from the markup calculation (Tables 1,2) is used in the EPPA model in the following way. Separate production structures are introduced for every power generation technology based on specification of their relative costs and input shares. For inputs, capital shares are calculated based on the capital recovery required, labor shares are calculated from O&M, and fuel shares are based on fuel costs. The markups define the relative costs of technologies in the base year of the model. Prices of inputs and

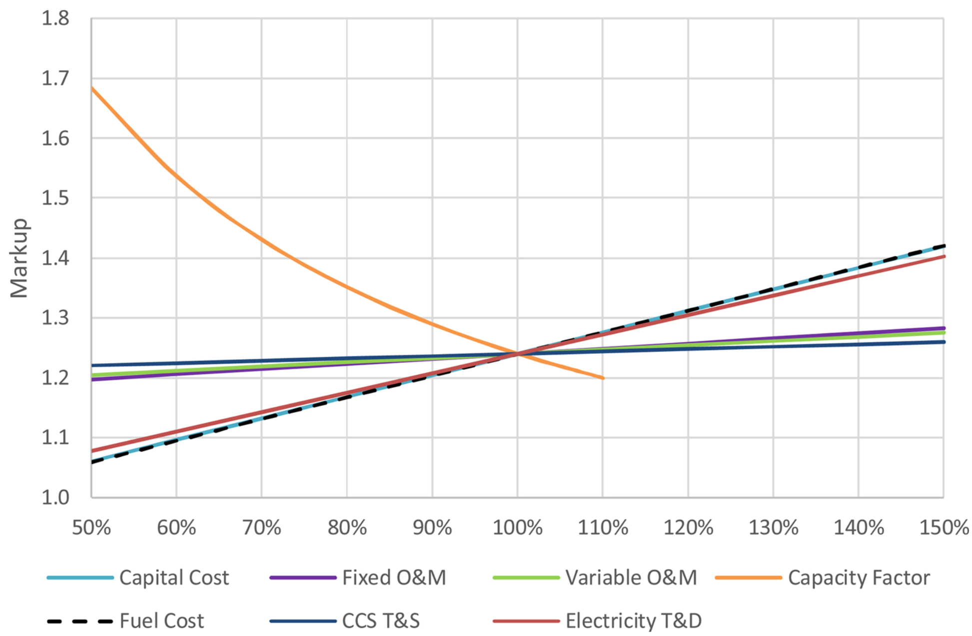

Fig. 5. Dependence of markup for *Gas with CCS* in USA on corresponding percent changes in input values.

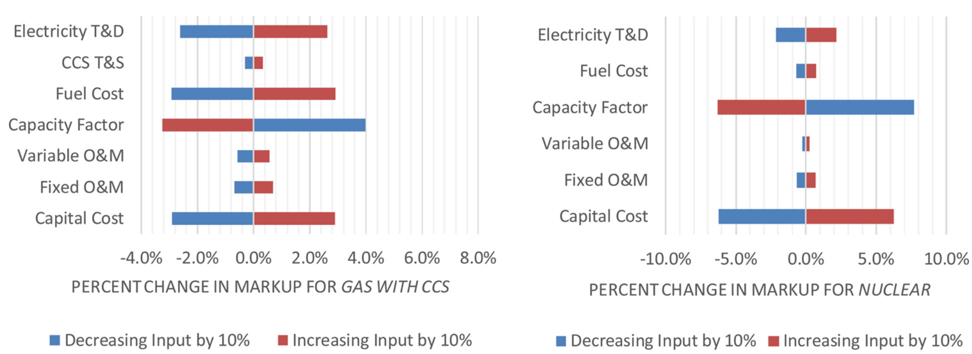

Fig. 6. Sensitivity of markups for *Gas with CCS* and *Nuclear* in the USA with a 10% increase and 10% decrease in input costs.

outputs are determined endogenously in the EPPA model, therefore, the input shares are used for initial calibration of representation of technologies.

The dynamics are represented in the following way. As prices change endogenously in the model over time, the input shares will change and the resulting markups will be determined by the model depending on the new economic conditions. These new relative costs will determine the economic competitiveness and deployment of different technologies. Increases in demand, resource depletion, international trade movements, development of substitutes, introduction of policies and other economic forces change the relative competitiveness of technologies. Under certain conditions, those technologies that are currently more expensive can become competitive (e.g., wind generation does not use fuel and so its cost is unaffected by changes in fuel prices, while the natural gas price could increase making gas generation more expensive). With exception of wind and solar[15], all other power generation technologies are fully dispatchable (including wind with backup). All technologies in the model are cost improving over time through several channels: 1) price-induced improvements driven by substitution effects; 2) autonomous energy efficiency improvement (an exogenous trend making technologies more energy-efficient over time based on econometric assessments of previous experience (Chen et al., 2016), and 3) processes that make the initial penetration of a new technology more expensive, and thereby slow its diffusion. With gaining experience with technology, costs are improving over time as a function of output from the technology (Morris et al., 2019).

5.2. Implications for the resulting technology mix

Table 8 provides a list of illustrative scenarios for the Reference (no climate policy) and the case where the greenhouse gas (GHG) emissions profile is consistent with the stabilization of the global average atmospheric temperature at 2 °C above pre-industrial levels with a probability of 66%.[16] Cases including the *BECCS* and *Gas with Advanced CCS* options, which are still at the early stage of development, are not shown here, although when these technologies are included, they play a large role in the electricity mix in 2 °C scenarios. The markups for *Nuclear* also does not reflect political constraints and other cost factors (such as permitting). For the simulations below, we therefore add a cost multiplier of 1.5 to the *Nuclear* markups to reflect these realities. We include in our model regional mandates for renewables based on IEA (2017). As such, renewables in all regions are required to expand regardless of their cost. We compare global power generation mix in the scenarios

[15] Wind and solar (without backup) are modelled as imperfect substitutes in the EPPA model.

[16] The policy scenarios are constructed with global economy-wide carbon pricing starting in 2020. Uncertainty quantification for the temperature increase is based on a 400-member ensemble of IGSM (Sokolov et al., 2018).

Table 8
Illustrative Scenarios.

Name	Description
Reference	No climate policy
2C *Base*	Global emission profile consistent with stabilization at 2 °C, reference cost assumptions, backup for non-dispatchable renewables at 100%
2C *low backup renewables*	Same as 2C Base, but the backup requirement for dispatchable renewables is reduced to 25%.
2C *half-cost CCS*	Same a 2C Base, but the markups for coal with CCS and gas with CCS are reduced (the difference between the CCS and non-CCS markups is cut in half)

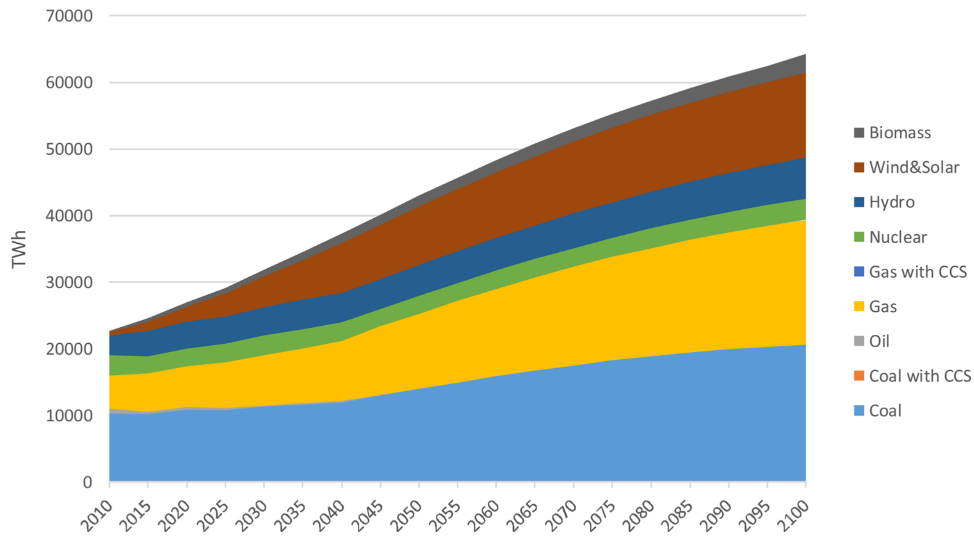

Fig. 7. Global electricity production in the *Reference* scenario.

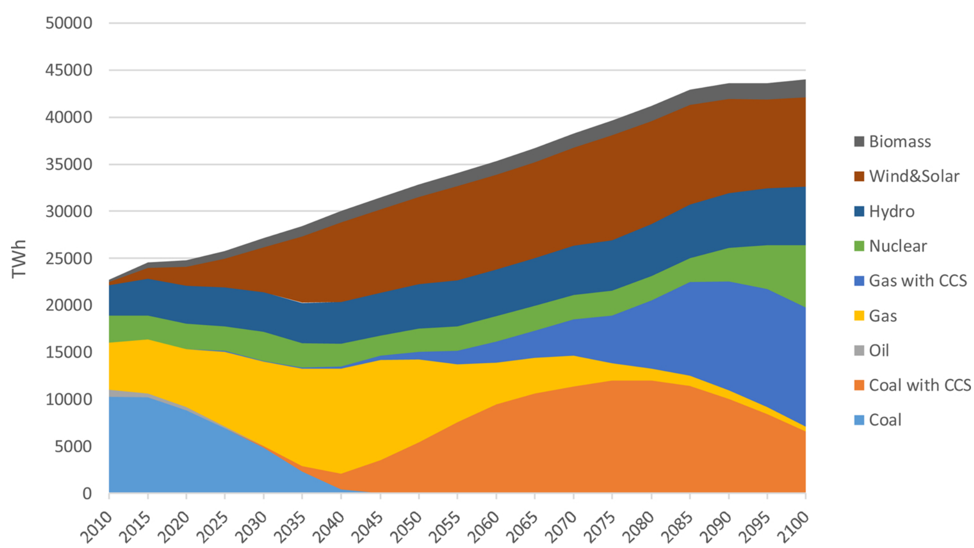

Fig. 8. Global electricity production in the 2C *Base* scenario.

described in Table 8.

For reporting, we combine all wind and solar generation (with and without backup) into a *Wind&Solar* category. Generation related to backing up wind by natural gas and biomass is reposted in the *Gas* and *Biomass* categories, respectively. The markup calculations described in Sections 2–3 are applied to newly installed generation. Inputs for existing fossil-fuel (coal, oil, natural gas) generation, existing nuclear and hydropower are taken from Chen et al (2016).

The electricity technology mix in the *Reference* scenario (Fig. 7) is dominated by *Coal* and *Gas* throughout the 21st century. *Gas* is the fastest growing power generation option on an absolute basis in this scenario. It grows 3.2 times from 2015 to 2100. *Wind&Solar* grows over 10 times from 2015 to 2100, but from a smaller base. Total global electricity production grows from about 25,000 TW h in 2015 to about 45,000 TW h by 2050 and to about 65,000 TW h in 2100.

While not a focus of this paper, we also performed a sensitivity analysis of the *Reference* scenario to the assumptions about the backup requirement and CCS costs. If the backup requirement for renewables is reduced to 25% in the *Reference* scenario, there is only a small increase in renewables globally because without a carbon price *Gas* and *Coal* still outcompete wind with backup. If the cost of CCS technologies is reduced in the *Reference* scenario in the same way as in the 2C *half-cost CCS* scenario, there is no impact on the results—without a carbon price, CCS options are not competitive with *Gas* and *Coal*.

In the policy scenario under the base assumptions about technology costs (2C *Base*), the generation mix (shown in Fig. 8) is significantly

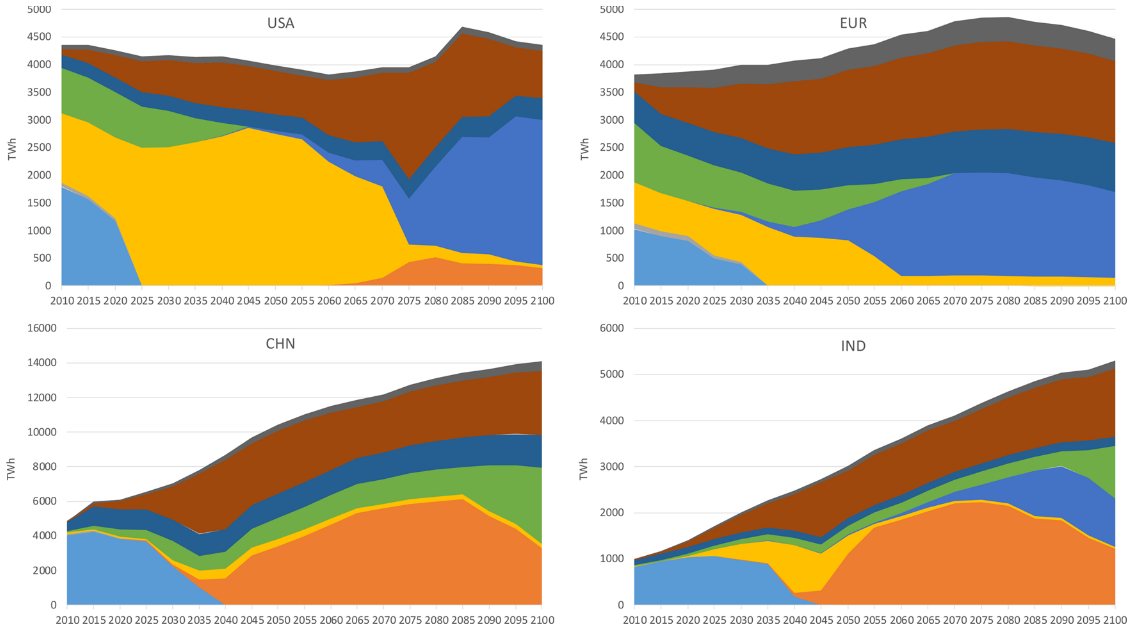

Fig. 9. Electricity production in the 2C *Base* scenario for selected regions.

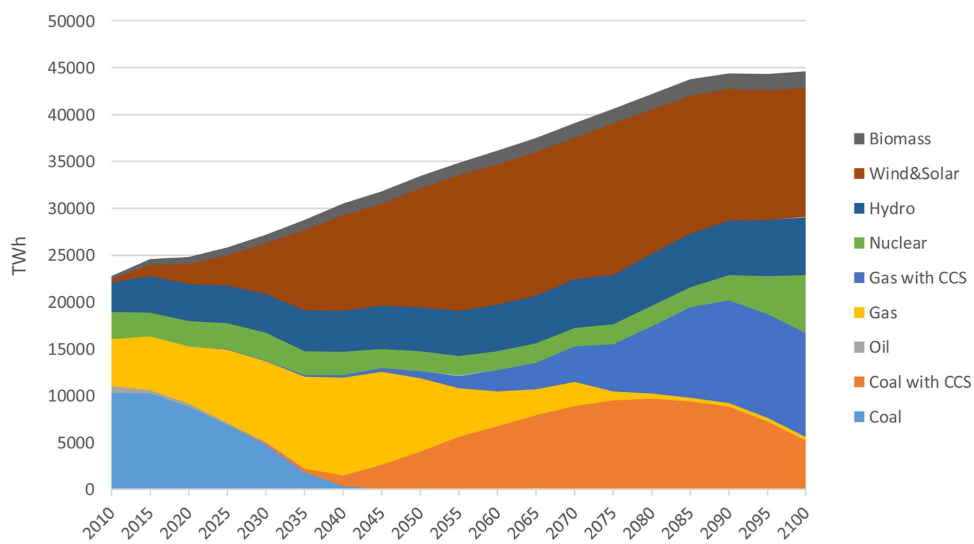

Fig. 10. Global electricity production in the 2C scenario with low backup renewables.

different than in the *Reference* scenario shown in Fig. 7. A large magnitude and fast pace of power sector transformation is modeled to keep the average global surface temperature below 2 °C relative to pre-industrial levels. *Coal* without CCS is phased out by 2040. *Gas* without CCS is greatly reduced by 2070. *Wind&Solar* generation supplies about 28% of the total electricity mid-century. CCS technologies play a large role in providing electricity by the end of the century. By 2100, generation is comprised of about 15% *Coal with CCS,* 29% *Gas with CCS,* 15% *Nuclear,* 14% hydro and 22% *Wind&Solar*. There is also a demand-side decrease of total electricity use which is modeled to be about 44,000 TW h by 2100 (compared to about 65,000 TW h in the *Reference* scenario).[17]

[17] The EPPA model includes some ability to electrify different sectors of the economy (mostly driven by elasticity of substitution), but many potential electrification pathways are not explicitly represented. With more aggressive electrification, total demand for electricity may not decrease as much as modeled in our 2C scenarios, and could potentially increase.

This global pattern is driven by several factors. Increasing carbon pricing drives *Coal* without CCS out of the mix faster than *Coal with CCS* is able to expand. Limitations for the speed of expansion are based on historical experience with different power generation technologies (Morris et al., 2019). In many regions, *Wind&Solar* initially expands to compensate for the reduction in fossil-based generation. However, once sufficient experience with CCS is gained, CCS technologies become competitive with *Wind&Solar* in several regions.

Fig. 9 shows the electricity mix for selected regions under the 2C *Base* scenario. Our analysis shows that world regions pursue quite different technology mixes. In USA in the first part of the century, *Gas* has the lowest markup and is therefore the preferred technology. It expands significantly until about 2045 when its competitiveness changes and natural gas-based generation begins to contract. As the carbon price increases over time with the policy, the carbon-inclusive price of natural gas also increases, until *Gas* is no longer the most economic technology. *Wind&Solar* continuously expand from 2010, mainly driven by renewable mandates assumed in the model. By 2070, *Gas with CCS* becomes the most economic technology. However, because it is a new

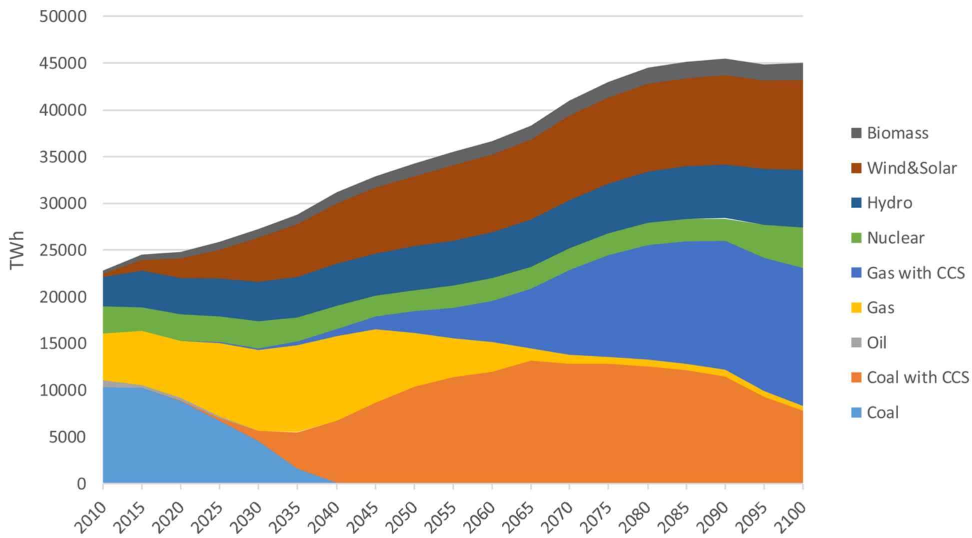

Fig. 11. Global electricity production in the 2C scenario with half-cost CCS.

technology to enter the power market, the rate of its expansion is limited (see Morris et al., 2019), for a description of representing penetration in the EPPA model). Therefore, wind and solar expand to fill the gap while the capacity to expand *Gas with CCS* continues to develop. Once *Gas with CCS* is able to expand more (after gaining experience with the technology), it grows faster and ultimately makes up about 60% of the electricity mix by 2100.

In Europe (EUR), *Wind&Solar* expand significantly, comprising about one third of the electricity mix by 2100. This expansion is supported by renewable mandates assumed in the model. By about 2040, *Gas with CCS* becomes the most competitive technology, ultimately expanding to 35% of total generation by 2100. The remaining third of generation in 2100 comes from hydro, biomass and the *Gas* (without CCS) that is used to backup wind.

In China (CHN), unlike USA and EUR, natural gas is expensive. Therefore, most of *Gas* (without CCS) is the amount needed to backup wind. *Wind&Solar* expand significantly over the century. By about 2040, *Coal with CCS* is the most economic technology and grows rapidly until about 2085. At that point, *Coal with CCS* contributes to almost half of the generation mix. After 2085, *Nuclear* begins to push out some of the *Coal with CCS*. Due to the falling cost of capital in CHN in the model, as well as the increasing penalty on the remaining 5% of emissions the *Coal with CCS* technology emits, *Nuclear* becomes the most economic. By 2100, *Nuclear* comprises about 30% of generation, *Coal with CCS* about 23%, *Wind&Solar* 26% and hydro 13%.

India (IND) shows a similar pattern to CHN, except it uses more *Gas* in early years and uses *Gas with CCS* in later years. By 2100, India's generation is made up of about 23% *Coal with CCS*, 20% *Gas with CCS*, 21% *Nuclear* and 28% *Wind&Solar*.

Region-specific costs and markups are crucial for the model to be able to reflect the market conditions of different regions and how the competition among technologies varies in each.

Fig. 10 shows the global electricity mix when the backup requirement for dispatchable renewables is reduced to 25%, making renewable technologies more cost competitive (the 2C *low backup renewables* scenario). With this cost advantage, *Wind&Solar* take over a larger share of the generation mix than under the base cost settings. By 2100, *Wind&Solar* comprise about 31% of the generation mix (compared to about 22% in the 2C *Base* scenario). Relative to the 2C *Base* scenario, *Wind&Solar* mainly replaces *Coal with CCS,* but there are also reductions in *Gas, Gas with CCS* and *Nuclear.*

If instead we assume CCS technologies are less expensive (the 2C *half-cost CCS* scenario) than in the base settings, then *Coal with CCS* and *Gas with CCS* take over a larger share of the generation mix. Fig. 11 shows the global electricity mix when we assume the difference in markups between the CCS and non-CCS versions of the technology is cut in half (i.e., the cost of the CCS component of the technology is cut in half). The markup for *Coal with CCS* becomes: *(Markup for Coal with CCS –Markup for Coal)*/2 + Markup *for Coal*. The same logic for CCS cost reduction is applied to *Gas with CCS*). Under this setting, both CCS technologies enter the generation mix sooner and grow more relative to the 2C *Base* scenario. In the 2C *Base* scenario, *Coal with CCS and Gas with CCS* together made up about 44% of generation by 2100. In the 2C *Cheap CCS* scenario, they comprise about 50%. This comes mainly at the expense of renewables.

These scenarios demonstrate the sensitivity of the model's electricity generation to assumptions about technology costs and markups. It is therefore important to have a clear and consistent approach, such as the *markup* approach, for calculating and comparing the costs of technologies in different regions.

6. Conclusion

Results generated by multi-region multi-sector energy-economic models are highly dependent on the costs assumed for the various electricity generating technologies. In the literature, these costs are generally given as levelized cost of electricity (LCOE). However, care must be taken when using LCOE, especially in comparing between dispatchable generators and intermittent generators. In this paper, we have built on the LCOE approach with what we term the *markup* method. This method provides a consistent comparison of the costs of the different electricity generating technologies, which can in turn be used in many energy-economic models. Markups are provided for six established generating technologies and seven advanced, but not yet established, generating technologies.

It is important to represent regional variations in capital and fuel costs. We divide the world into 18 regions. Using the GTAP database, we provide fuel and capital cost data, as well as electricity prices, for each region, allowing us to calculate a full set of markups unique to each region.

Our sensitivity analysis shows that capital cost, fuel cost, and capacity factor can substantially affect the resulting markups. However, these results will vary in magnitude for different generating technologies. For instance, fuel costs have a big impact on coal, gas, and biomass, but little to no impact on nuclear, wind, and solar. On the other hand, capital cost only has a modest impact on gas, but a large impact on nuclear, wind and solar.

To illustrate the use of the markups in an economy-wide energy-economic model, we used the EPPA model to run several scenarios. Deployment of different low-carbon power generation technologies depends on carbon policy stringency and assumptions about the costs of these low-carbon technologies. Our scenarios of a low-carbon future do not reveal a single dominating technology. Rather several technologies contribute to the resulting generation mix in the second half of the 21st century: *Wind&Solar*, *Nuclear*, *Coal with CCS* and *Gas with CCS*. However, the importance of these technologies varies by region. Comparing the USA, Europe, China and India: Europe has the biggest share of *Wind&Solar*, the USA is heavily dependent on *Gas with CCS*, and China and India both use significant amounts of *Coal with CCS* and *Nuclear* (while there is almost none of those used in the USA and Europe). Running scenarios for "low backup renewables" and "half-cost CCS" has the expected result of increasing the shares of these reduced-cost technologies. However, while the increase is significant, it is not overwhelming. The results for each of those scenarios still show a mix of generating technologies and no silver bullets.

In summary, our methodology for modeling the economic competition between different technologies in multi-sector multi-region energy-economic models based on a markup approach offers a tool for these models to analyze long-term scenarios of energy development.

Acknowledgements

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Appendix A. Data sources for lcoe and markup calculations

Table A1
Data sources for established power generation technologies.

		Coal	Gas	Biomass	Wind	Solar	Nuclear
[1]	"Overnight" Capital Cost	IEA (2015)	IEA (2015)	IEA (2015)	IEA (2015)	IEA (2015)	IEA (2015)
[2]	SCALED Overnight Capital Cost						
[3]	Total Capital Requirement						
[4]	Capital Recovery Charge Rate						
[5]	Fixed O&M	IEA (2015)	IEA (2015)	EIA (2017)	IEA (2015)	IEA (2015)	IEA (2015)
[6]	Variable O&M	IEA (2015)	IEA (2015)	EIA (2017)	IEA (2015)	IEA (2015)	IEA (2015)
[7]	Project Life						
[8]	Capacity Factor	IEA (2015)	IEA (2015)		EIA (2017)	EIA (2017)[a]	IEA (2015)
[9]	(Capacity Factor Wind)						
[10]	(Capacity Factor Biomass/NGCC)						
[11]	Operating Hours						
[12]	Capital Recovery Required						
[13]	Fixed O&M Recovery Required						
[14]	Efficiency	IEA (2015)	IEA (2015)	Cuellar & Herzog (2015)[b]			
[15]	Heat Rate						EIA (2017)
[16]	Fuel Cost	GTAP	GTAP	GTAP	GTAP	GTAP	
[17]	Fuel Cost per kWh						IEA (2015)
[18]	Levelized Cost of Electricity						
[19]	Transmission and Distribution						
[20]	Levelized Cost of Electricity incl. T&D						
[21]	EPPA Base Year Elec Price	GTAP	GTAP	GTAP	GTAP	GTAP	GTAP
[22]	Markup Over Base Elec Price						

Cells with additional notes to Table A1 are shaded in grey.

[a] For solar, the EIA capacity factor is reported in AC (alternating current), and so we convert it to DC (direct current). EIA reports that the solar capacity factor for the average US climate (like Kansas City) is 26% MWh/MW-AC. This assumes an inverter loading ratio of 1.3 (at peak production, the modules produce 1.3x the inverter capacity), which is typical for the U.S. Since the data we are using from IEA are based on DC, we need the capacity factor in terms of DC as well, and so need to convert EIA's number. 26% in AC / 1.3 for inverter = 20% in DC.

[b] While not relevant for cost calculations, it is worth noting that for the EPPA model we assume that biomass generation emits on net 10% of the emissions embedded in the biomass to account for CO_2 emissions associated with biomass harvesting, transport, etc., as well as emissions associated with any fertilizer use. See Cuellar & Herzog (2015) for more details.

Table A2
Data sources for advanced power generation technologies.

		Coal with CCS	Gas with CCS	BECCS	Coal+Bio CCS	Gas with Advanced CCS	WindGas	WindBio
[1]	"Overnight" Capital Cost	Rubin et al. (2015)		Biomass from IEA (2015); CCS scaled from Rubin et al. (2015)[a]			Wind from IEA (2015); Gas turbine from EIA (2017)	IEA (2015)
[2]	SCALED Overnight Capital Cost							
[3]	Total Capital Requirement		Rubin et al. (2015)[b]		Scaled from Rubin et al. (2015)[c]	NET Power		
[4]	Capital Recovery Charge Rate							
[5]	Fixed O&M	IEA (2015) scaled by NETL (2015)[d]	IEA (2015) scaled by NETL (2015)[d]	Cuellar & Herzog (2015)	Scaled from Rubin et al. (2015)	Scaled from Rubin et al. (2015)[e]	Wind from IEA (2015); Gas turbine from EIA (2017)	IEA (2015)
[6]	Variable O&M	IEA (2015) scaled by NETL (2015)	IEA (2015) scaled by NETL (2015)	Scaled from Rubin et al. (2015)[f]	IEA (2015) scaled by NETL (2015)[g]	IEA (2015) scaled by NETL (2015)[h]	Wind from IEA (2015); Gas turbine from EIA (2017)	IEA (2015)
[7]	Project Life	EIA (2017)	EIA (2017)	EIA (2017)	EIA (2017)	EIA (2017)	EIA (2017)	EIA (2017)
[8]	Capacity Factor							
[9]	(Capacity Factor Wind)							
[10]	(Capacity Factor Biomass/NGCC)							
[11]	Operating Hours							
[12]	Capital Recovery Required							
[13]	Fixed O&M Recovery Required							
[14]	Efficiency	IEA (2010)	Efficiency decrease based on Coal with CCS	Efficiency decrease based on Coal with CCS	See the note (i) below the table			Cuellar & Herzog (2015)
[15]	Heat Rate						EIA (2017)	
[16]	Fuel Cost	GTAP	GTAP	GTAP	GTAP	GTAP	GTAP	GTAP
[17]	Fuel Cost per kWh							
[18]	Levelized Cost of Electricity							
[19]	Transmission and Distribution							
[20]	Levelized Cost of Electricity incl. T&D	GTAP	GTAP	GTAP	GTAP	GTAP	GTAP	GTAP
[21]	EPPA Base Year Elec Price							
[22]	Markup Over Base Elec Price							
	For CCS							
[23]	Amount Fossil Fuel							
[24]	Carbon Content	EPA (1998)	EPA (1998)	PFPI	EPA (1998)	EPA (1998)	EPA (1998)	PFPI
[25]	Carbon Emissions							
[26]	Carbon Dioxide Emissions							
[27]	Percent Emissions Captured	See the note (j) below the table	NETL (2015)		See the note (j) below the table	NET Power		
[28]	CO2 Emissions Captured							
[29]	Cost of CO2 T&S	Rubin et al (2015)	Rubin et al (2015)	Rubin et al (2015)	Rubin et al (2015)	Rubin et al (2015)		
[30]	CO2 Transportation and Storage Cost							

Cells with additional notes to Table A2 are shaded in grey.

[a] To calculate overnight capital cost for *BECCS*, we take the overnight capital cost for *Biomass* and add the difference in capital cost between *Coal with CCS* and *Coal*, and then we adjust that value to account for the efficiency derating between *Biomass* and *BECCS*.

[b] Overnight capital cost is not provided in Rubin et al. (2015) for *Gas with CCS*, but total capital requirement of $2061/kW is provided (in 2013$). It is then converted to 2015$ and scaled by the regional capital scaling factor.

[c] Total capital requirement for *Coal + Bio CCS* is calculated by adding $150/kW to the total capital requirement for *Coal with CCS* and adjusting for the change in efficiency (and then scaling by the regional capital factor). The $150/kW reflects the additional cost related to co-firing.

[d] For the fixed and variable costs for *Coal with CCS* and *Gas with CCS* we take the fixed and variable costs for *Coal* and *Gas* from IEA and then proportionally scale them based on the cost differences for those inputs between the CCS and non-CCS coal and gas technologies from NETL (2015). For consistency, we use the capital costs from IEA rather than NETL.

[e] Fixed O&M for *Gas with Advanced CCS* is calculated by taking the fixed O&M for *Gas* and scaling it by the ratio of the total capital requirement (before regional scaling) between *Gas with Advanced CCS* and *Gas*.

[f] Variable O&M for *BECCS* is calculated by scaling the variable O&M for *Biomass* by the ratio of variable O&M between *Coal* and *Coal with CCS*.

[g] Variable O&M is assumed to be the same for *Coal + Bio CCS* as *Coal with CCS* and the fixed O&M is assumed to cost an additional $15.5/kW relative to *Coal with CCS*.

[h] Variable O&M and the capacity factor for *Gas with Advanced CCS* is assumed to be the same as for *Gas*.

[i] The efficiency for *Coal + Bio CCS* is assumed to be 32% (based on the calculation that the addition of 7.6% biomass decreases the *Coal with CCS* efficiency by 0.68 percentage points).

[j] The capture rate for *Coal with CCS* and *Coal + Bio with CCS* is taken to be 95%, based on the experience with the Petra Nova coal CCS project.

Appendix B. Comparison of data from varying sources

Cost estimates can vary significantly. The differences in cost estimates for capital costs, capacity factors, efficiencies, fixed costs, and variable costs depend on the make and model of the gas or steam turbine and the operating or testing conditions. This section seeks to analyze the cost estimates of a variety of NGCC turbines with and without CCS and pulverized coal with CCS.

The cost estimates for NGCC turbines include both F-Class Turbines and H-Class Turbines. F-Class turbine technology was commercialized in 1985, surpassing the market share of D- and E-class turbines in 1995 (Ducker, 2015). H-Class turbines began commercialization in the late 1990s, and in 2015, H-Class turbines exceeded the market share of F-Class turbines. The cost estimates for coal with CCS includes pulverized coal, with NETL providing information for supercritical pulverized coal.

The cost estimates come from a range of different resources. The Annual Energy Outlook (AEO) releases cost estimates for both F- and H-class NGCC turbine technology yearly (EIA, 2015; EIA, 2016). The NETL data on the H-Turbine was retrieved from the report provided on coal- and natural gas-fired electricity generation (NETL, 2015). The cost estimates from Rubin et al determined the capital costs and efficiencies and NGCC turbines, but does not provide fixed or variable cost estimates (Rubin et al., 2015). Cost estimates for the United States were retrieved from the IEA's report on the Projected Costs of Generating Electricity (IEA, 2015). The data values from General Electric (GE) are based on an H-Class Turbine and were obtained via correspondence.

The data for NGCC turbines is in Table B1 below, the data on NGCC with Carbon Capture is in Table B2 below, and the data on coal with CCS is in Table B3 below. The costs associated with CCS do not include CO_2 transportation and storage costs. The final LCOE calculation for each electricity producer is shown below. Table B1 shows the cost estimates for both F- and H-Class turbines, if specified by the report. LCOE values range from \$0.047/kWh to \$0.051/kWh, averaging \$0.049/kWh. In the AEO reports, F-Class turbines have lower capital and fixed costs than H-Class turbines, but have lower efficiencies and higher heat rates. The GE values for capital cost are much lower than other values provided, but has a lower capacity factor than the other turbines, leading to a higher LCOE.

Table B1
Cost Estimates for NGCC Turbines (in 2013$).

Data Source Type of Turbine		AEO2015 F Turbine	AEO2015 H Turbine	AEO2016 F Turbine	AEO2016 H Turbine	NETL F Turbine	Rubin et al -	IEA -	GE H Turbine
"Overnight" Capital Cost	$/kW	912	1017	928	1048	863	971	1001	724
Total Capital Requirement	$/kW	985	1098	1002	1132	932	1049	1081	782
Fixed O&M	$/kW/yr	13.16	15.36	10.44	9.49	25.98	-	29.40	7.45
Variable O&M	$/MWh	3.6	3.27	3.32	1.90	1.75		2.7	1.8
Capacity Factor		87%	85%	87%	87%	85%	85%	85%	60%
Efficiency		48%	54%	52%	54%	51%	51%	55%	52%
Heat Rate (HHV)	MJ/kWh	7.44	6.68	6.96	6.65	6.99	7.06	6.58	6.94
Levelized Costs	$/kWh	0.051	0.049	0.048	0.047	0.048	-	0.050	0.048

Table B2
Cost Estimates for NGCC Turbines with CCS (in 2013$).

Data Source		AEO2015	AEO2016	NETL	Rubin et al
Type of Turbine		H Turbine	H Turbine	F Turbine	-
"Overnight" Capital Cost	$/kW	2072	2069	1858	1840
Total Capital Requirement	$/kW	2321	2318	2080	2061
Fixed O&M	$/kW/yr	31.77	31.73	50.41	-
Variable O&M	$/MWh	6.80	6.76	4.08	-
Capacity Factor		80%	87%	85%	85%
Efficiency		46.0%	45.3%	45.7%	44.0%
Heat Rate (HHV)	MJ/kWh	7.83	7.94	7.88	8.18
Levelized Costs	$/kWh	0.080	0.077	0.074	-

Table B3
Cost Estimates for Coal Power Plant with CCS (in 2013$).

Data Source		NETL	Rubin et al
Type of Coal Plant		PC Supercritical	-
"Overnight" Capital Cost	$/kW	4462	3817
Total Capital Requirement	$/kW	5354	4580
Fixed O&M	$/kW/yr	118.08	-
Variable O&M	$/MWh	15.14	-
Capacity Factor		85%	85%
Efficiency		32.5%	31.6%
Heat Rate (HHV)	MJ/kWh	11.09	11.40
Levelized Costs	$/kWh	0.132	-

Table B2 shows the cost estimates for NGCC turbines with carbon capture, with LCOE values ranging from \$0.074/kWh to \$0.080/kWh, averaging \$0.077/kWh. The fixed costs reported by NETL are much greater than the values reported by AEO, but the variable costs are much lower, with similar heat rates. When compared to NGCC turbines without CCS, turbines with CCS, on average, have 108% greater overnight costs, 140% greater fixed costs, 118% higher variable costs, 15% greater heat rates, and 57% LCOE values.

Table B3 shows various cost estimates for pulverized coal with CCS. NETL reports greater capital costs, fixed costs, and variable costs than Rubin et al (2015), but reports a similar heat rate to the other data values.

Appendix C. Regional markups

See Fig. C1 and Table C1

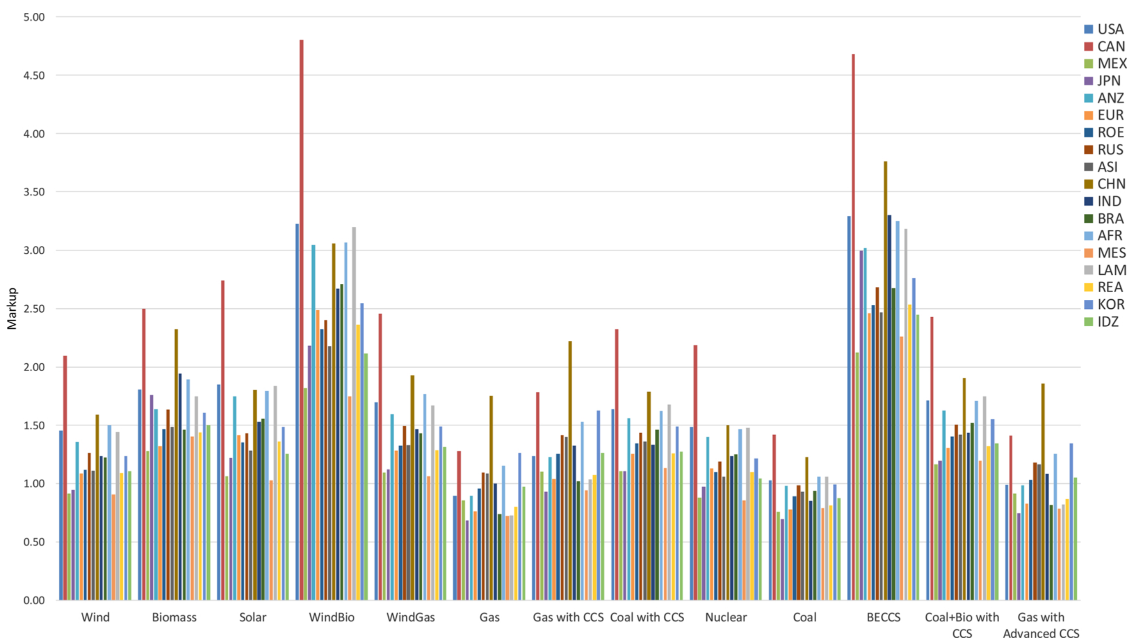

Fig. C1. Median markups for technologies in different regions.

Table C1
Range of Markups for technologies in different regions.

		Coal	Gas	Biomass	Wind	Solar	Nuclear	Coal with CCS	Gas with CCS	BECCS	Coal + Bio CCS	Gas with Advanced CCS	WindGas	Windbio
USA	Min	0.69	0.76	1.08	0.70	1.27	0.86	1.39	1.08	2.14	1.47	0.86	0.93	1.15
	Median	1.03	0.89	1.80	1.45	1.85	1.49	1.64	1.23	3.30	1.71	0.99	1.70	3.23
	Max	1.39	1.08	2.76	2.98	3.02	2.31	2.48	1.77	5.66	2.56	1.16	3.00	7.27
CAN	Min	0.91	1.08	1.33	0.98	1.93	1.21	1.97	1.57	2.75	2.07	1.21	1.29	1.57
	Median	1.42	1.28	2.50	2.10	2.74	2.18	2.32	1.78	4.68	2.43	1.41	2.46	4.81
	Max	1.93	1.55	4.05	4.42	4.49	3.37	3.52	2.60	8.35	3.63	1.69	4.45	11.19
MEX	Min	0.58	0.77	1.01	0.49	0.67	0.58	0.94	0.99	1.77	1.00	0.84	0.68	0.86
	Median	0.75	0.85	1.28	0.92	1.07	0.88	1.11	1.10	2.12	1.16	0.92	1.09	1.82
	Max	1.00	1.04	1.64	1.72	1.71	1.40	1.67	1.60	3.20	1.73	1.09	1.76	3.56
JPN	Min	0.47	0.59	1.27	0.45	0.85	0.55	0.94	0.83	2.33	1.03	0.66	0.61	0.79
	Median	0.70	0.69	1.76	0.95	1.22	0.98	1.11	0.93	3.00	1.20	0.75	1.12	2.18
	Max	0.93	0.84	2.41	1.97	1.99	1.51	1.67	1.37	4.92	1.76	0.90	1.99	4.92
ANZ	Min	0.65	0.77	0.94	0.65	1.21	0.80	1.32	1.09	1.87	1.39	0.86	0.86	1.05
	Median	0.98	0.89	1.64	1.36	1.74	1.40	1.56	1.23	3.02	1.63	0.98	1.59	3.05
	Max	1.31	1.09	2.57	2.81	2.85	2.16	2.36	1.79	5.26	2.43	1.17	2.84	6.95
EUR	Min	0.51	0.66	0.72	0.51	1.00	0.63	1.06	0.93	1.47	1.12	0.72	0.68	0.82
	Median	0.78	0.76	1.32	1.09	1.42	1.13	1.25	1.04	2.46	1.31	0.83	1.28	2.49
	Max	1.04	0.93	2.12	2.29	2.32	1.74	1.89	1.53	4.37	1.95	1.00	2.31	5.78
ROE	Min	0.66	0.85	1.04	0.57	0.89	0.69	1.14	1.13	1.89	1.21	0.93	0.78	0.97
	Median	0.89	0.96	1.47	1.11	1.35	1.10	1.34	1.25	2.53	1.40	1.03	1.33	2.32
	Max	1.18	1.17	2.03	2.18	2.18	1.73	2.02	1.83	4.05	2.08	1.23	2.22	4.87
RUS	Min	0.78	0.98	1.33	0.69	0.87	0.82	1.22	1.25	2.29	1.29	1.09	0.95	1.21
	Median	0.98	1.09	1.64	1.26	1.43	1.19	1.43	1.41	2.68	1.50	1.18	1.49	2.40
	Max	1.32	1.31	2.03	2.30	2.29	1.90	2.17	2.01	3.91	2.25	1.38	2.34	4.49

(continued on next page)

Table C1 (*continued*)

		Coal	Gas	Biomass	Wind	Solar	Nuclear	Coal with CCS	Gas with CCS	BECCS	Coal + Bio CCS	Gas with Advanced CCS	WindGas	Windbio
ASI	Min	0.72	0.98	1.17	0.60	0.80	0.71	1.16	1.26	2.04	1.22	1.07	0.83	1.04
	Median	0.93	1.09	1.48	1.11	1.28	1.06	1.36	1.40	2.47	1.42	1.16	1.33	2.18
	Max	1.23	1.33	1.90	2.07	2.06	1.69	2.05	2.03	3.70	2.11	1.39	2.12	4.23
CHN	Min	0.97	1.59	1.95	0.87	1.10	1.03	1.52	2.02	3.33	1.64	1.73	1.24	1.55
	Median	1.23	1.75	2.33	1.59	1.80	1.50	1.79	2.22	3.76	1.90	1.86	1.92	3.05
	Max	1.66	2.14	2.83	2.90	2.88	2.40	2.72	3.25	5.46	2.83	2.23	3.00	5.69
IND	Min	0.60	0.88	1.42	0.62	1.02	0.75	1.13	1.19	2.57	1.23	0.97	0.85	1.07
	Median	0.85	1.00	1.94	1.24	1.53	1.24	1.33	1.32	3.30	1.43	1.08	1.47	2.67
	Max	1.16	1.22	2.63	2.46	2.48	1.94	2.03	1.93	5.29	2.13	1.29	2.50	5.71
BRA	Min	0.64	0.63	0.86	0.59	1.07	0.72	1.25	0.89	1.69	1.30	0.71	0.78	0.97
	Median	0.93	0.74	1.46	1.22	1.56	1.25	1.46	1.02	2.68	1.52	0.82	1.43	2.71
	Max	1.24	0.89	2.26	2.51	2.54	1.94	2.21	1.46	4.62	2.26	0.96	2.52	6.10
AFR	Min	0.78	1.02	1.37	0.78	1.16	0.94	1.37	1.35	2.47	1.46	1.13	1.06	1.33
	Median	1.06	1.15	1.89	1.50	1.79	1.47	1.62	1.53	3.25	1.71	1.25	1.77	3.06
	Max	1.45	1.39	2.59	2.89	2.89	2.31	2.47	2.18	5.12	2.55	1.48	2.93	6.28
MES	Min	0.63	0.64	1.19	0.50	0.63	0.59	0.97	0.82	2.03	1.03	0.72	0.67	0.89
	Median	0.79	0.72	1.40	0.91	1.03	0.85	1.13	0.94	2.26	1.20	0.79	1.07	1.75
	Max	1.04	0.86	1.69	1.65	1.64	1.36	1.71	1.32	3.27	1.77	0.91	1.68	3.25
LAM	Min	0.72	0.60	1.03	0.70	1.26	0.85	1.42	0.88	2.03	1.50	0.70	0.90	1.14
	Median	1.06	0.73	1.75	1.44	1.83	1.47	1.68	1.04	3.19	1.75	0.82	1.67	3.20
	Max	1.42	0.86	2.69	2.96	2.99	2.29	2.53	1.44	5.49	2.60	0.95	2.96	7.20
REA	Min	0.57	0.70	0.95	0.54	0.92	0.66	1.07	0.95	1.78	1.13	0.77	0.73	0.91
	Median	0.81	0.80	1.44	1.09	1.36	1.10	1.26	1.07	2.53	1.32	0.87	1.29	2.36
	Max	1.09	0.97	2.08	2.19	2.21	1.71	1.90	1.55	4.19	1.97	1.03	2.22	5.15
KOR	Min	0.74	1.14	1.16	0.64	0.97	0.77	1.27	1.49	2.09	1.33	1.23	0.90	1.09
	Median	0.99	1.26	1.61	1.23	1.48	1.21	1.49	1.63	2.76	1.55	1.34	1.49	2.55
	Max	1.32	1.55	2.21	2.39	2.40	1.91	2.24	2.41	4.38	2.31	1.63	2.46	5.28
IDZ	Min	0.69	0.88	1.24	0.61	0.67	0.72	1.08	1.12	2.12	1.15	0.97	0.83	1.07
	Median	0.88	0.98	1.50	1.11	1.25	1.04	1.27	1.26	2.45	1.34	1.05	1.31	2.11
	Max	1.18	1.17	1.85	2.02	2.44	1.67	1.93	1.79	3.57	2.00	1.24	2.06	3.95

Note: These markups use the data sources detailed in Appendix A. The Median, Minimum and Maximum markups use the median, min and max values for cost inputs from IEA (2015).

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