End of the load?

Challenging power technology assumptions

About Carbon Tracker

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Executive Summary

What is the cheapest technology?

Carbon Tracker's work on the energy transition has already demonstrated the value in challenging traditional energy model assumptions. There is a confusing picture in the energy debate about which technologies are the cheapest option, yet the world is clearly at a point where more renewables are getting built and there is uncertainty about new coal and gas plants. Levelised Costs of Electricity (LCOEs) provide one way of comparing the costs of technologies, although it is widely recognized that there are large ranges of values for each technology, and that other important factors such as daily peak pricing and the system value of wind and solar also come in to play. It is clear that the answer to the question "Which is the cheapest?"; is: "It depends". This analysis is an attempt to demonstrate why it is useful for those using LCOEs to make investment or policy decisions to challenge the underlying assumptions, and understand how the landscape is changing. This research highlights how a series of modest incremental changes to average LCOE assumptions can have a profound cumulative impact on the affordability of power generation technologies.

Our approach

The analysis uses a simplified LCOE calculator provided by the US National Renewable Energy Laboratory (NREL), which includes the standard factors that determine a global average LCOE. We compare four new-build utility scale plants: coal, gas, wind, and solar. We then vary some of the fundamental assumptions based on three key scenarios, and track how the relative LCOEs respond. The three scenarios are:

2016 reference scenario (2016 reference) to provide a reference point based on widely used technical assumptions from which to show relative LCOE sensitivity.

2016 updated scenario (2016 updated) to show the impact of a series of updated assumptions that may be used for an actual investment decision today, based on real world inputs as seen in today's electricity markets. The updated scenario includes updated assumptions on (i) the cost of capital for renewable energy (ii) the capacity factors for fossil fuel plants (iii) the lifetimes from premature retirements of fossil fuel plants and (iv) carbon pricing for fossil fuels plants.

2020 2 degrees pathway scenario (2020 2D) uses assumptions for an investment decision made in 2020 in an electricity system that is moving towards keeping global average temperatures to 2D. The 2D pathway scenario includes updated assumptions on (i) the capex costs of renewable energy (ii) the capacity factors for fossil fuel plants (iii) the financing costs of fossil fuels and (iv) carbon pricing for fossil plants.

The assumptions of each scenario are detailed in the table below.

	Technology	Capex *US$/MW*	Lifetime *years*	Discount rate *%*	Capacity factor *%*	Carbon price *($/tCO2)*
2016 Reference	Solar	1.2	25	9%	18%	-
	Wind	1.7	25	9%	30%	-
	Gas	0.9	35	9%	60%	$0
	Coal	2.0	40	9%	80%	$0
2016 Updated	Solar	1.2	25	8%	18%	-
	Wind	1.7	25	8%	30%	-
	Gas	0.9	25	9%	38%	$5
	Coal	2.0	20	9%	59%	$5
2020 2D	Solar	0.9	25	8%	20%	-
	Wind	1.6	25	8%	40%	-
	Gas	0.9	25	10%	31%	$10
	Coal	2.0	20	10%	42%	$10

Fuel prices ($80/t for coal and $7/mmbtu for gas) and all other variables are consistent throughout – see full report.

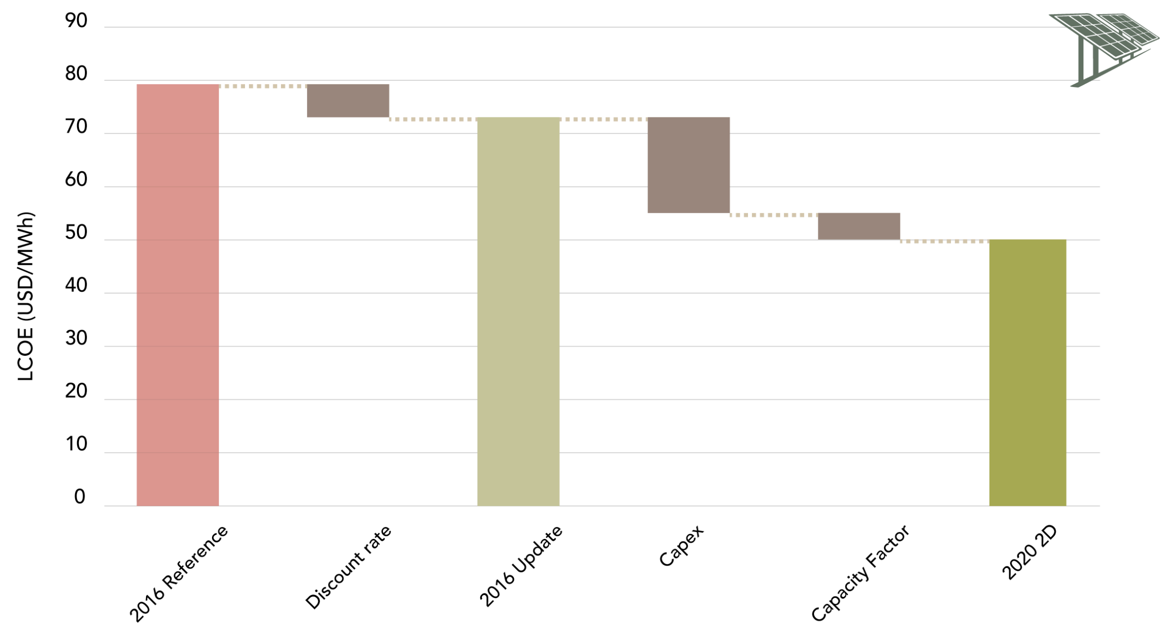
Starting point – technical assumptions (2016 reference)

A number of energy institutions provide the reference technical assumptions that make up the default values assigned to theoretical electricity generation plants. For example, coal plants are designed to run at high capacity factors, so this would be the standard industry reference point. There are also typical assumptions in financial analysis based on historical performance, such as the lifetime of a plant. An LCOE comparison using these reference points makes the average fossil fuel plants cheaper, but reflects the electricity system of the past, rather than that of today, let alone tomorrow. The waterfall charts below show how the LCOEs are progressing through this time series, and the key factors that are contributing.

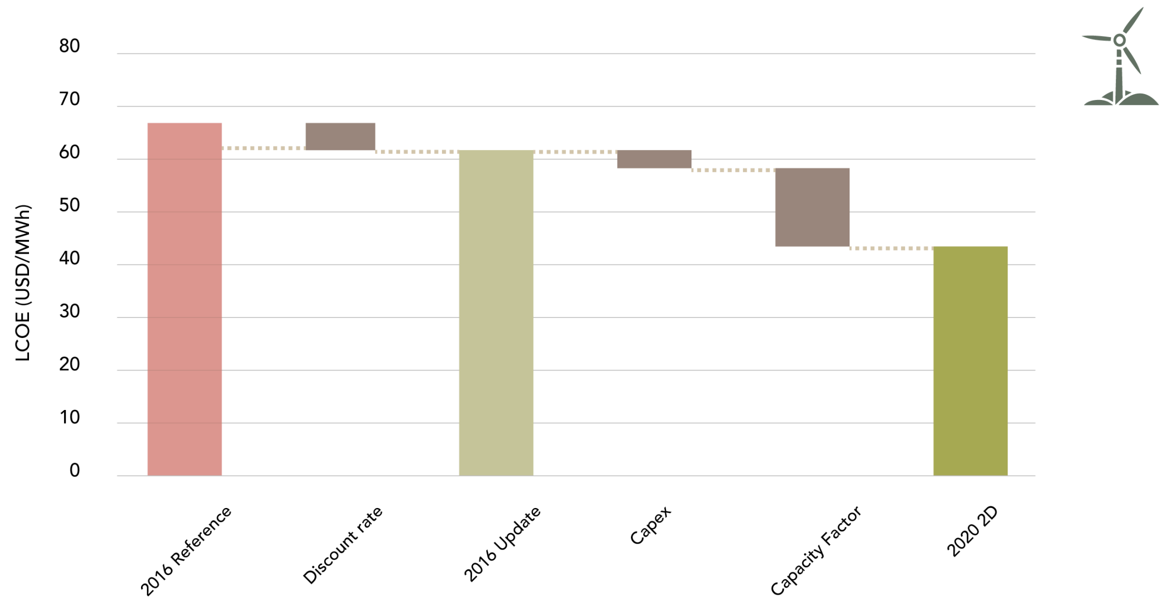
Assumptions based on today's operating environment (2016 updated)

When you start looking at the actual situation for new utility-scale generation options being considered today, the picture can be very different to the reference technical specifications seen initially. Putting aside the ranges, even the averages can be significantly different. For example, the average capacity factor for global coal generation in 2013 was 59% and for gas 38% – each over 20 percentage points below the typical reference utilisation levels published. The expected lifetimes have also been shortened to 25 years for gas and 20 years for coal, which reflects the fact that average carbon intensity has to fall to get to lower emissions levels. The unique characteristics of renewables projects are also bringing new players into the equation; who have new business models and lower capital costs, which tend to benefit renewables options due to preferential dispatch and higher capex costs.

Evolution of solar LCOE across the three scenarios



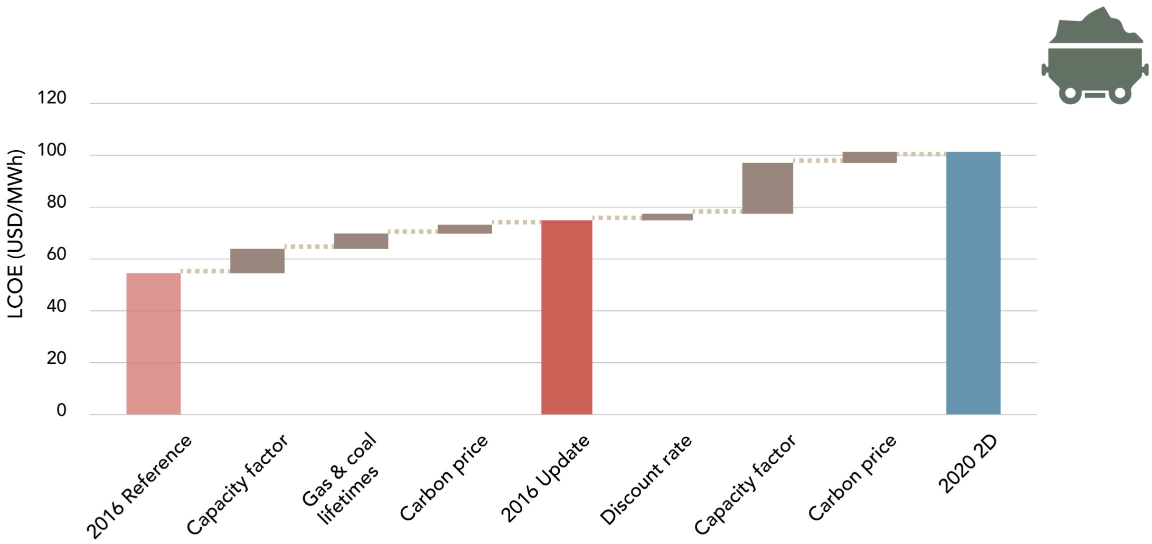
Evolution of wind LCOE across the three scenarios



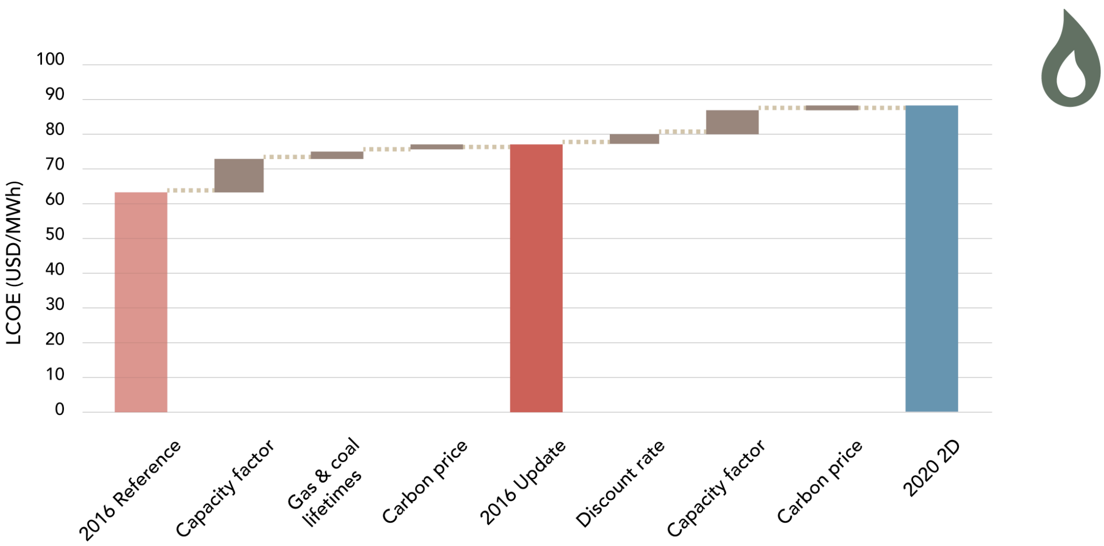
Looking forward to a low carbon future (2020 2D)

The energy transition is clearly underway, driven by an unstoppable confluence of policy momentum, technological advances and new business models. Using static projections for the variables clearly doesn't make sense, yet not all models are structured to include these changes over time. The learning rate for renewables combined with higher than expected rates of deployment combine to provide ongoing reductions in the capital costs of solar and wind. Increased renewables generation then displaces fossil fuel powered generation, further depressing capacity factors for coal and gas. To show how far this could move, we have applied falling gas and coal utilization rates derived from the IEA's ETP 2DS scenario to the LCOE projections. As the risks of the fossil fuel sector emerge, this will likely push up the costs of financing and refinancing for carbon-intensive activities.

Evolution of gas LCOE across the three scenarios



Evolution of coal LCOE across the three scenarios



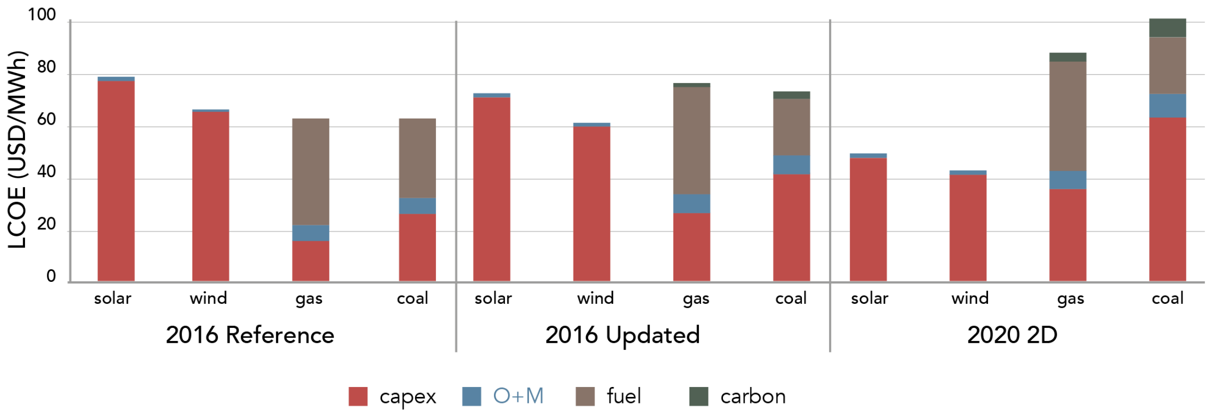
Renewables better on average in 2016 – with or without a carbon price

It is worth reiterating that there are a range of LCOEs for any technology, and global LCOE averages cannot give a definitive answer as to what is the better investment in a specific situation. However, what the global averages with real world 2016 assumptions tell us is that already the average LCOEs for solar and wind are lower than their coal and gas competitors. The 2016 updated and 2020 2D scenarios apply a conservative carbon price of US$5/ton and US$10, respectively. These carbon price levels and other environmental policies (such as air pollution regulations) may in fact be higher in some regions.

Importantly, the LCOEs for wind and solar in the 2016 updated scenario are not dependent on our carbon pricing assumptions to come out lower than coal and gas. It should also be noted that fuel prices for coal (US$80/t) and gas (US$7/mmbtu) plants could decline significantly in the future, potentially compromising the competitiveness of wind and solar. However, in our 2020 2D scenario it is clear that on average, even very low fuel prices would not tip the advantage back to fossil fuels.

This suggests that the tide has turned, and is borne out by the growing number of locations where unsubsidized renewables are being built. It also shows why any investors basing their investment decisions on coal and gas continuing to be the cheapest source of electricity could be deeply misguided, given the relative shifts this LCOE sensitivity shows.

Comparison of LCOE results across all scenarios



Other important factors beyond LCOE

LCOE analysis is a limited metric as it does not consider revenues from generation and the system value of wind and solar. Different technologies are supported in different ways around the world for different reasons. For example, new renewables plants are more likely to benefit from favourable congestion payments than new fossil fuel plants, as suitable renewable sites are typically more distributed than fossil fuel plant sites. The potential for higher revenues can boost renewables' competitiveness as they can avoid grid congested locations and solar can match peak demand attracting a price premium. Going forward, the challenge for policymakers is no longer whether wind and solar will become competitive with fossil fuel plants, but rather how to integrate variable renewable energy (VRE) to maximize system value. According to the IEA, the best way to integrate VRE is to transform the overall power system through system-friendly deployment, improved operating strategies and investment in additional flexible resources. Flexible resources include better located generation, grid infrastructure, storage and demand side integration.

Direction of travel

Our 2020 2D scenario demonstrates how it can become a self-fulfilling prophecy, as growth in renewables brings their costs down and raises the costs of coal and gas. Not all will be ready to base decisions on this scenario yet – but it shows that the economic logic of a renewable energy + balancing services future increases the closer we get to this electricity generation mix. The end of high load factors for coal and gas make it very challenging to continue backing new plants where this situation is emerging.

Checklist for challenging LCOE assumptions

- **Use a starting point which reflects the current reality of operation, not technical specifications**
- **Use dynamic projections to understand how variables such as utilisation rates may change over time**
- **Consider how lifetimes may be shorter than expected given decarbonisation trends**
- **Review how fossil fuel risk premiums may increase the cost of capital for coal and gas**
- **Identify how new business models and lower cost-of-capital project owners and developers can lower the costs for renewables**
- **Ensure the virtuous circle of increased renewables installation and learning rates feeds into capex cost assumptions**
- **Identify other key market factors, e.g. electricity price premiums, grid congestion payments**

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Introduction

The levelised cost of energy (LCOE) is a common analytical tool used to compare electricity generation technologies, and is widely used in electricity market analysis and modelling[1]. Whilst the limitations of using generic LCOE analysis for understanding the economics of a specific plant have been well documented[2], a confused picture is still being represented in energy debates. This report undertakes a scenario analysis to understand how the global average LCOEs of power technologies can be over or underestimated. It focuses on bringing together more appropriate assumptions to LCOE analysis to highlight the more likely upside potential for renewables and downside risks for fossil fuels.

The report uses a simplified LCOE calculator provided by the US National Renewable Energy Laboratory (NREL), which includes the standard factors that determine a global average LCOE[3]. The report focuses on comparing the LCOEs of four power technologies (i) pulverised ultra-supercritical coal plant (ii) combined cycle gas turbine (CCGT) plant (iii) onshore wind plant and (iv) utility-scale fixed axis crystalline silicon photovoltaic solar plant. We then vary some of the fundamental assumptions based on three key scenarios, and track how the relative LCOEs respond. The three scenarios are:

> ***2016 reference scenario*** *to provide a reference point based on widely used technical assumptions from which to show relative LCOE sensitivity.*
>
> ***2016 updated scenario*** *to show the impact of a series of updated assumptions that may be used for an actual investment decision today, based on real world inputs as seen in today's electricity markets. The updated scenario includes updated assumptions on (i) the cost of capital for renewable energy (ii) the capacity factors for fossil fuel plants (iii) the lifetimes from premature retirements of fossil fuel plants and (iv) carbon pricing for fossil fuels plants.*
>
> ***2020 2D pathway scenario*** *uses assumptions based on an investment decision made in 2020 in an electricity system that is moving towards keeping global average temperatures to 2 degrees. The 2D pathway scenario includes updated assumptions on (i) the capex costs of renewable energy (ii) the capacity factors for fossil fuel plants (iii) the financing costs of fossil fuels and (iv) carbon pricing for fossil plants.*

The report has two main sections. The first section details the assumptions underpinning the 2016 reference scenario and then explores the impact of a series of more appropriate input assumptions based on the 2016 updated and 2020 2D scenarios. This section showcases how the transition that global electricity markets are undergoing has already reduced the cost of renewables and increased the cost of fossil fuels – a trend likely to continue in the future as the world moves towards a 2D pathway. This analysis illustrates why any investment decisions based on coal and gas continuing to be the cheapest source of electricity could be unwise.

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[1] Used in various reports by the International Energy Agency, Bloomberg New Energy Finance, The Energy Information Administration, the National Renewable Energy Laboratory, among other leading research and analysis organisations. See the appendix for examples of prominent LCOE studies.

[2] See for e.g., IEA (2105), Projected Costs of Generating Electricity. Available: https://www.iea.org/bookshop/711-Projected_Costs_of_Generating_Electricity and IEA (2016), Next-generation wind and solar power: From cost to value. Available: https://www.iea.org/publications/freepublications/publication/NextGenerationWindandSolarPower.pdf.

[3] NREL (2016), Levelised Cost of Energy Calculator. Available: http://www.nrel.gov/analysis/tech_lcoe.html.

The second section recognises that revenues received will be affected some other important price factors beyond LCOE analysis which investors and policymakers should consider. LCOE is a limited metric, as it fails to consider revenues and the system value of renewable energy. We provide an example of how the potential for higher revenues can boost renewables' competitiveness, as they can avoid grid congested locations. We also detail the wider debate in policy circles about the macro impact of variable renewable energy (VRE) on electricity markets and how policymakers can integrate wind and solar to maximize system value.

We conclude by providing a checklist for challenging LCOE assumptions for power generation technologies.

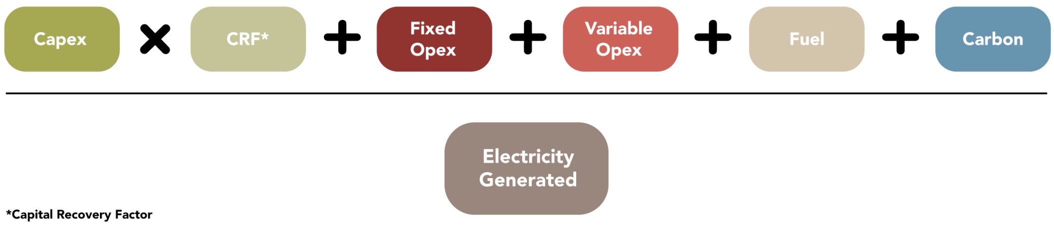
1. LCOE scenario analysis

This section is an investigation into LCOE sensitivities. The approach sets a typical reference point that shows how a series of traditional theoretical input assumptions leads to fossil fuels appearing to be the lower cost sources of electricity generation. Then more appropriate input assumptions based on the transition that global electricity markets are undergoing show how renewables costs can be significantly improved whilst fossil fuel costs increase.

Box 1. What is LCOE analysis?

The LCOE is simply the sum of all costs divided by the amount of generation. The LCOE is commonly used to assist investors, policymakers and researchers to guide discussions and decision-making in energy investments. Several excellent studies have been conducted in the past, which cover the strengths and limitations of LCOE analysis, (see Appendix). The approach used in this report is the simplified LCOE calculation outlined in the National Renewable Energy Laboratory's (NREL) LCOE calculator[4]. The simplified LCOE calculation uses a Capital Recovery Factor (CRF) to turn the initial capex expenditure into a stream of equal annual payments based on the discount rate and plant lifetime.

Figure 1 – Components of LCOE



1.1 2016 reference scenario

Our reference scenario uses common assumptions from industry sources based on an investment decision made today which lead to coal and gas appearing to be the lowest cost sources of new electricity generation. LCOEs vary widely between sources, and between best case and worst case situations, with the variances being due to input assumptions and methodological differences. It may be argued that other inputs are more suitable or comparable, and most of these inputs are almost always site- and country-specific, i.e. these inputs will change if the fossil fuels are domestically produced or imported, if they are taxed, if the local debt interest rate is different, if a larger or smaller plant was required, etc. For the purpose of this report we require a reference point from which we will investigate the impact of improved assumptions. It is therefore the relative differences rather than the absolute values of the LCOEs that is of interest. The assumptions used in the 2016 reference scenario are detailed in Table 1 below.

[4] NREL (2016), Levelised Cost of Energy Calculator. Available: http://www.nrel.gov/analysis/tech_lcoe.html.

Table 1. Assumptions used for 2016 reference scenario

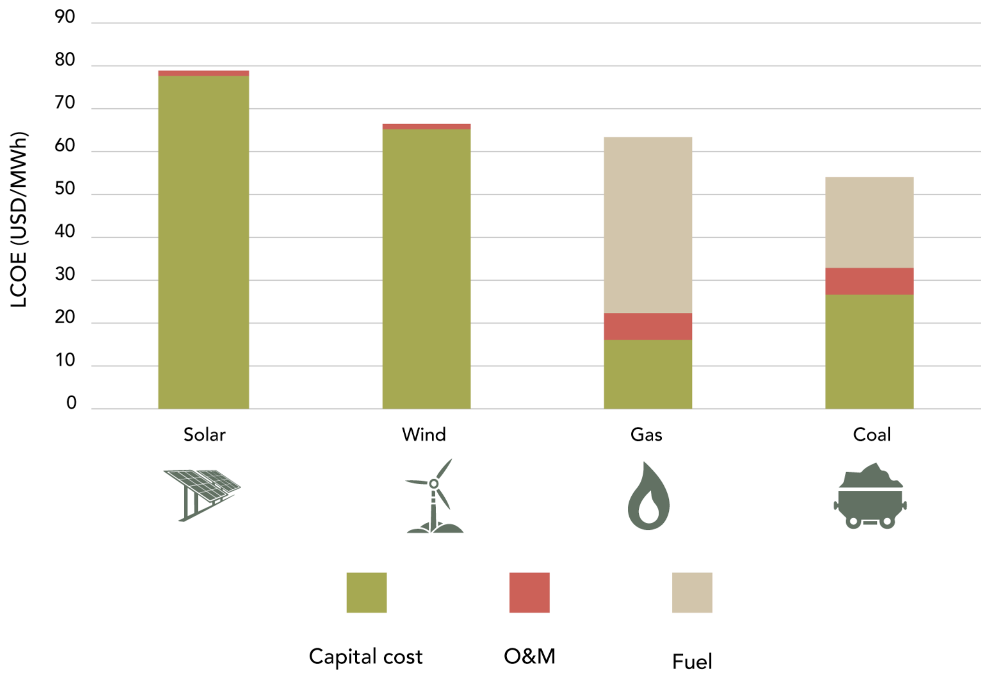
	Solar	Wind	Gas	Coal
Lifetime (years)	25	25	35	40
Capex (US$/MW)	1.2	1.7	0.9	2
Capacity (MW)	100	100	500	600
Capacity factor (%)	18	30	60	80
Fixed Opex (US$/MW/year)	20	25	12	30
Variable Opex (US$/MWh/year)	0	0	5	4
Efficiency (%)	0	0	58	46
Fuel cost (US$/mmbtu)*	0	0	41	21
Discount rate (%)	9	9	9	9
Carbon price (US$/t)	-	-	0	0

Source: see appendix

* Represents a fuel price of US$80/t for coal and US$7/mmbtu for gas.

Figure 2 details the LCOE when the assumptions in Table 1 are inputted into the model. Coal is easily the cheapest form of electricity on an LCOE basis, followed by gas, wind and solar, respectively.

Figure 2. LCOE of 2016 reference scenario



Source: see appendix

1.2 2016 updated scenario

The updated scenario uses updated assumptions based on an investment decision made today, taking into consideration structural changes emerging in electricity systems throughout the world. The updated scenario includes updated assumptions on (i) the cost of capital for renewable energy (ii) the capacity factors for fossil fuel plants (iii) the lifetimes from premature retirements of fossil fuel plants and (iv) carbon pricing for fossil plants. The assumptions used in the 2016 updated scenario are detailed in Table 2 and discussed below.

Table 2. Modified assumptions for the 2016 updated scenario*

	Solar	Wind	Gas	Coal
Lifetime (years)	25	25	25	20
Capacity factor (%)	18	30	38	59
Discount rate (%)	8	8	9	9
Carbon price (US$/t)	-	-	5	5

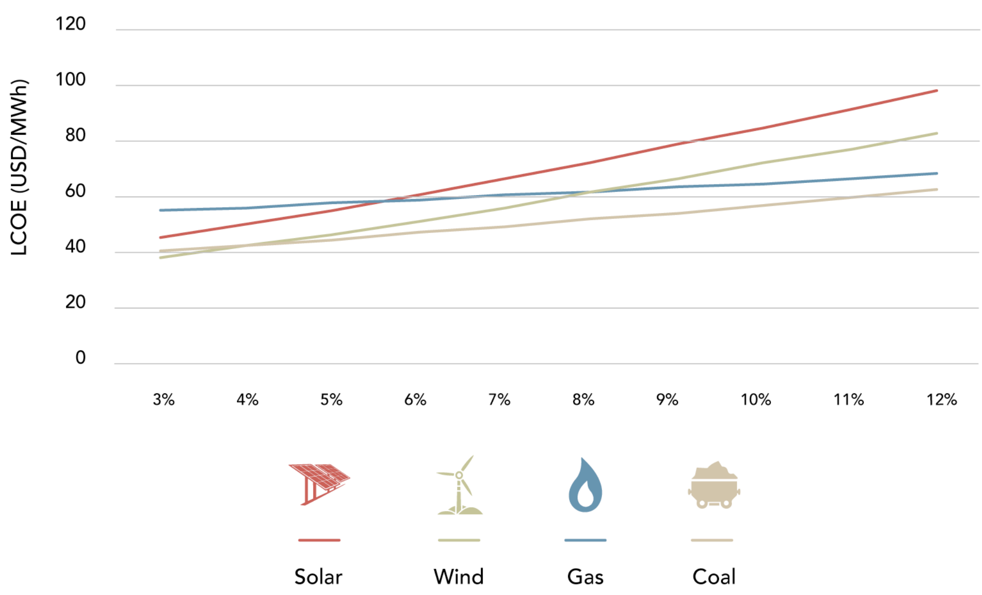
Source: see appendix

* All other input assumptions are the same as the 2016 reference scenario.

1.2.1 Impact of reduced cost of capital for renewable energy

Financing structures and the cost of capital are major inputs into all electricity plants' costs, and are relatively more important for renewable projects, as the initial capital expenditure is a larger share of total costs, i.e. lower costs of capital lead to lower LCOEs, which benefit renewables more than fossil fuel plants. Figure 3 shows that when the LCOE is varied over a range of discount rates the impact on the capital intensive renewable technologies is greater. The steeper lines for wind and solar reflect that with a higher proportions capital costs their LCOEs are more sensitive to reducing the discount rate than coal or gas.

Figure 3. LCOE sensitivity to discount rates assuming other factors unchanged



Source: see appendix, CTI analysis

There are many factors that can impact the choice of discount rate, and the cost of capital for a project. Some factors are location- or country-specific, and are identical for all electricity plants. Some factors are specific to a certain electricity project or technology. And some factors are specific to the investor or owner of the project. Table 3 details factors which impact project financing.

Table 3: Factors impacting project financing

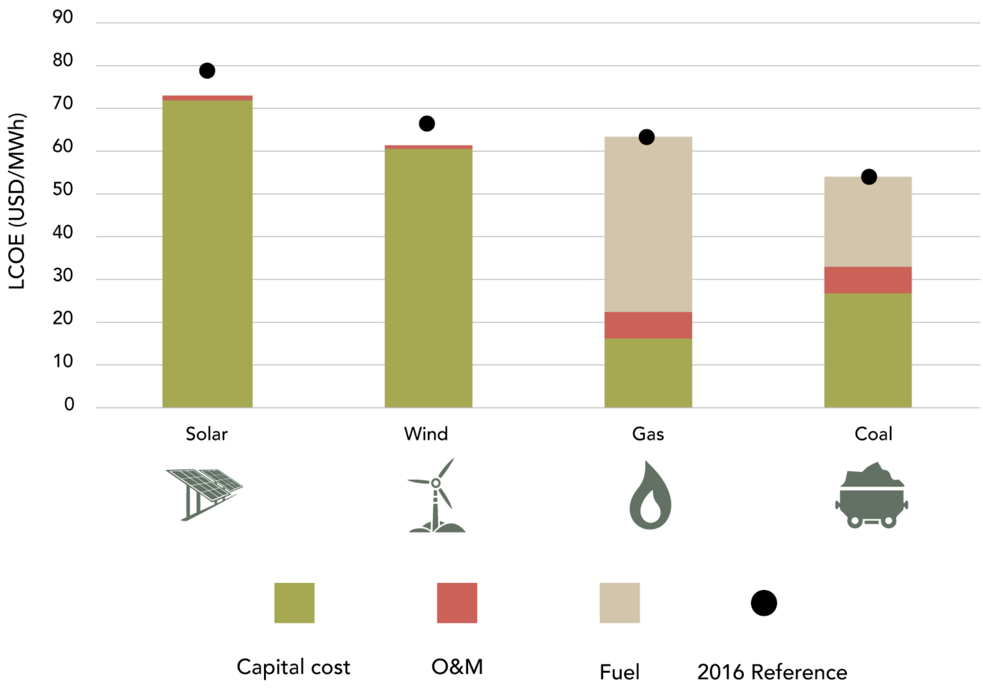
Factor	Description	Drivers and Impact on Cost of Capital
Debt rate	The interest rate of bank loans, typically lower than the equity return rate as debt investors have seniority in the case of bankruptcy.	The debt rate is driven by the underlying risk-free debt rate, plus a debt margin.
Equity return	The return that equity investors require, which is higher than debt rates as equity investors take more risk.	Return is driven by risk of the project, which may include a premium for various types of risks such as country risk, development risk, technology risk, electricity price risk, fuel price risk.
Debt/Equity ratio (gearing)	The ratio of debt (lower rate) to equity (higher rate), where the share of each source of capital changes the overall cost of capital.	Lower gearing ratios may be preferred for riskier projects. Lower gearing results in a higher cost of capital and higher project costs.
Investor/owner's cost of capital	Different companies have different cost of capital based on their risk profile.	A project can have a lower LCOE if it's investor/owner has a lower cost of capital.

In electricity markets with limited experience of solar and wind projects there may also be tendencies for the inclusion of risk premiums and lower gearing (debt component) in financing of renewables, leading to higher discount rates. As annual installations of solar and wind increase – in 2015 there was more onshore wind and utility-scale solar PV installed globally than coal and gas capacity combined[5] – and as financial markets become familiar with the risks and returns of these projects, risk premiums should be removed and gearing levels may increase in the future.

As renewables projects are becoming more commonplace globally, risk profiles are decreasing, and investors and developers with a lower cost of capital are developing and operating renewables projects, a lower cost financial structure than that chosen for the reference case is appropriate for the two renewables technologies. Figure 4 assumes that the reference discount rate of 9% is reduced to 8% for solar and wind, leading to solar's LCOE decreasing by $6/MWh and wind's by $5/MWh.

[5] BNEF (2016), New Energy Outlook. Available: http://www.bloomberg.com/company/new-energy-outlook/.

Figure 4 – Impact of lower cost of capital compared to 2016 reference scenario



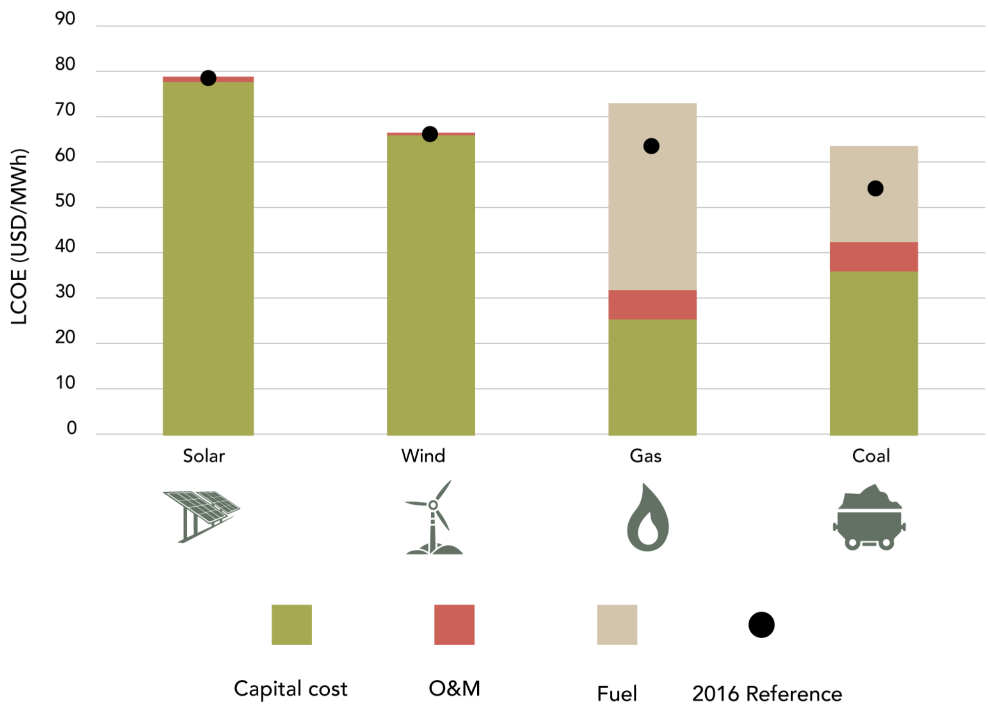
Source: see appendix, CTI analysis

1.2.2 Impact of reduced capacity factors for fossil fuel plants

Capacity factors commonly used in global average LCOEs are higher than those seen in operating plants. According to the IEA's Energy Technology Perspectives (ETP) 2016, the implied global average capacity factor for gas plants in 2013 was 38%, and for coal plants was 59%[6]. This compares to 60% and 80% respectively in the technical reference case – i.e. over 20 percentage points lower for each (see Box 2). Figure 5 shows the impact of these reduced capacity factors based on actual data, resulting in a US$10/MWh increase for the LCOE of both gas and coal.

[6] IEA (2016), Energy Technology Perspectives. Available: http://www.iea.org/etp/.

Figure 5. Impact of lower capacity factors for gas and coal plants compared to 2016 reference scenario

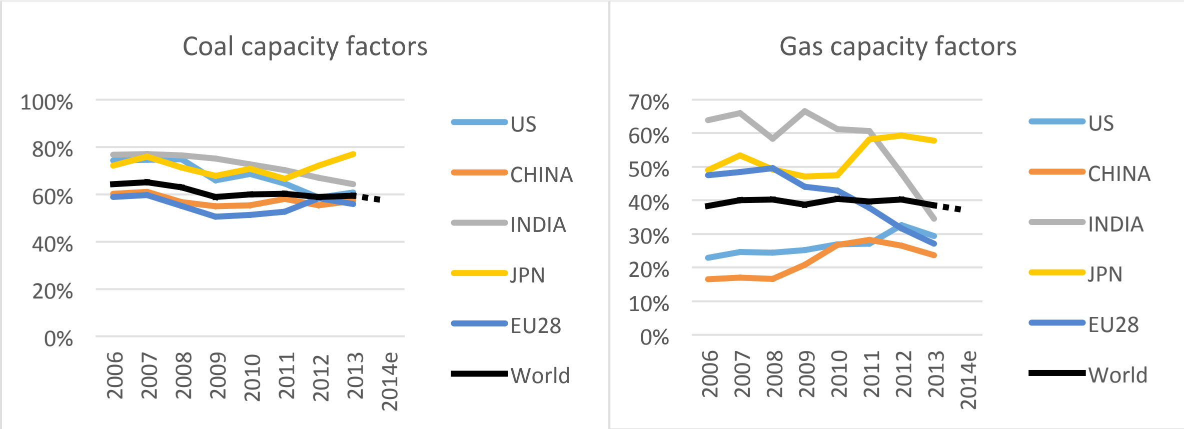


Source: see appendix, CTI analysis

Box 2. Historical capacity factors of coal and gas plants

The rate at which the capacity factor for fossil fuel plants degrades will depend on market specific factors, such as rates of penetration of renewables and overall electricity demand growth or reduction, and plant specific characteristics such as ramp rates, flexibility, and plants cost relative to other fossil fuel generators. However, from 2006 to 2013, capacity factors for coal-fired power plants have historically ranged between around 65-55%. Since 2007 the average capacity factor of coal plants worldwide has decreased by 9% from 65% in 2007 to 59% in 2013. Across the major markets, it appears the average capacity factor of coal plants peaked in 2007. The exception is Japan, which ran its coal plants harder after the 2010 Fukushima Daiichi disaster and led to its operating nuclear plants being shut down. Regarding gas plants, a distinction needs to be made between combined cycle gas turbines, (CCGTs), and open cycle gas turbines (OCGTs), which tend to operate at base load and mid and peak load, respectively. However, the average capacity factors of all gas plants has declined 4% from 2007 to 2013. Although not included in our updated 2016 scenario assumptions, we estimate the global average capacity of coal and gas plants in 2014 was 57% and 37%, respectively.

Figure 6. Average historical capacity factors of coal and gas plants in major markets



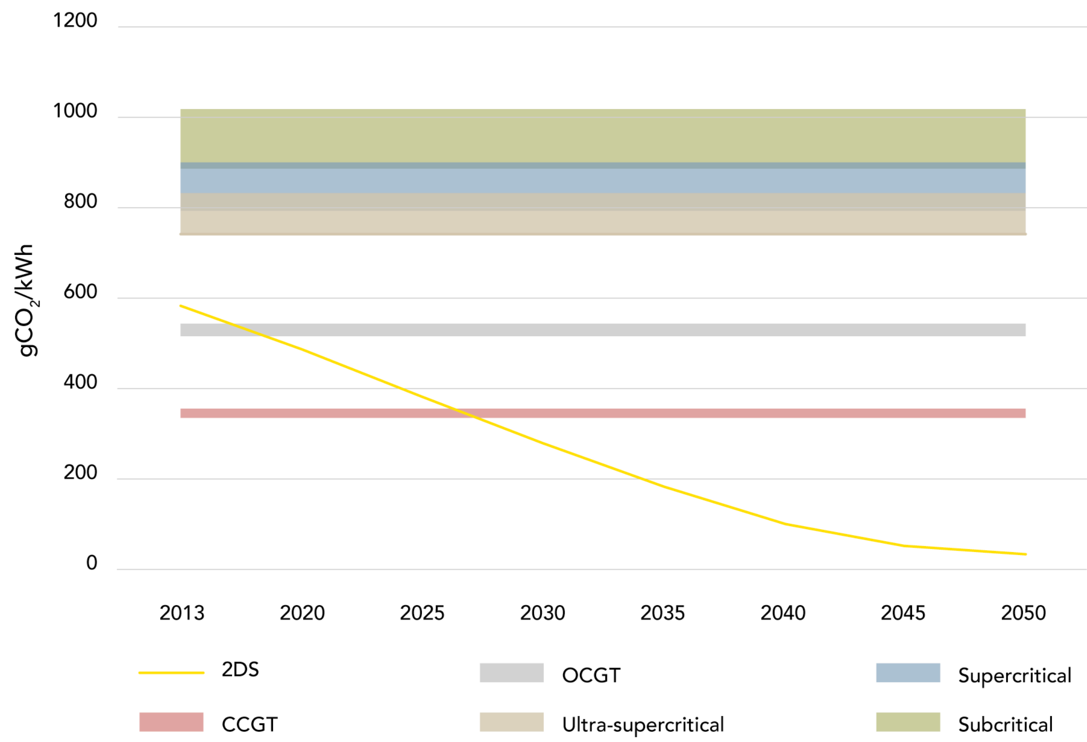
Source: World Energy Outlook (2008-2015), Energy Technology Perspectives (2016), CTI analysis

** ETP 2016 is used for the 2013 data point rather than WEO 2015 due to further validation and verification. 2014 data is based on a CTI estimate.*

1.2.3 Impact of reduced lifetimes for coal and gas plants

Efforts to reduce greenhouse gases, improve air quality and reduce water use are likely to produce a vastly different electricity generation sector from today. Historically, most variations in electricity plant lifetimes were lifetime extensions via refurbishments, however the emerging trend is towards reduced lifetimes for fossil fuel plants. In order for the world to meet the decarbonisation targets of the 2D pathway, global electricity generation will need to be largely carbon-free by 2050. The assumption that an unabated coal or gas plant built today will operate for 35-45 years is not valid if the world is to remain below the 2D limit. Figure 7 compares the average carbon intensity of power generation in the IEA's ETP 2°C scenario (2DS) from 2013-50, with typical carbon intensities of coal and gas plant technologies. Based on World Energy Investment Outlook (2014) assumptions, subcritical coal plant technologies emit 1020-890 gCO_2/kWh, while supercritical technologies emit 900-795 gCO_2/kWh and ultra-supercritical emit 835-740 gCO_2/kWh. CCGT emit 355-335 gCO_2/kWh and OCGT emit 545-520 gCO_2/kWh, respectively. Figure 7 highlights how a large share of fossil fuel generation in the generation mix is inconsistent with the reducing average carbon intensity for power generation in the IEA's 2DS, meaning that the lifetimes of both existing and new build fossil fuels plants will likely need to be shortened.

Figure 7. Carbon intensity of coal and gas plant technologies relative to average carbon intensity for power generation under the 2DS*

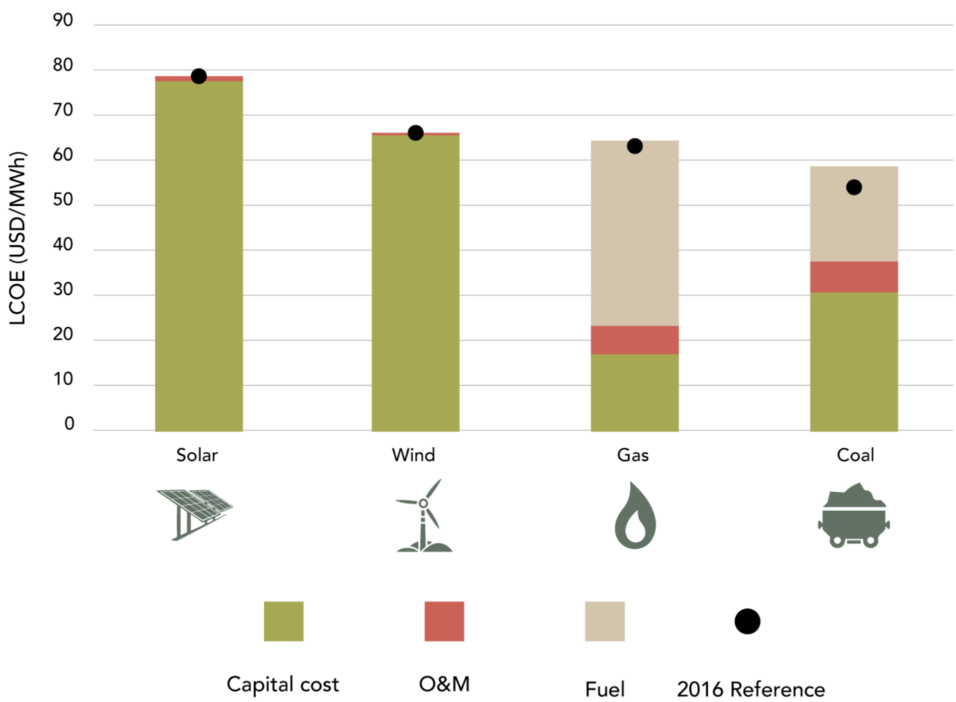


Source: Energy Technology Perspectives (2016), World Energy Investment Outlook (2014), CTI analysis

* based on plant efficiencies (gross, LHV): subcritical (34-39%), supercritical (38-43%), ultra-supercritical (41-46%), CCGT (57-60%) and OCGT (37-39%). Emissions factors of 95 kt/PJ for coal and 56 kt/PJ for gas. We acknowledge this assessment does not consider combined heat and power or CCS-equipped plants.

The combination of worsening economics and further decarbonisation efforts necessitates more appropriate lifetime assumptions. It is foreseeable that as capacity factors decrease leading to lower revenues and making new fossil plants uncompetitive, the same effect is likely to lead to early retirements of existing plants. Without knowing the future retirement year of plants built today, for illustrative purposes coal and gas plants built today are assumed to operate for 20 and 10 years less respectively compared to the reference assumptions. Figure 8 shows LCOEs with a gas lifetime of 25 years and a coal lifetime of 20 years, resulting in gas' LCOE increasing by $1/MWh and coal's by $5/MWh.

Figure 8. Impact of reduced lifetimes for gas and coal compared to 2016 reference scenario



Source: see appendix, CTI analysis

This report assumes Carbon Capture and Storage (CCS) will not be available to extend the lifetimes of fossil fuel plants, as the costs will likely be prohibitively expensive. There is currently one CCS-equipped coal-fired power plant operating in the world today (Boundary Dam in Canada) and 12 plants in development. The last coal plant to start construction in the US, is the Kemper County integrated gasification combined cycle (IGCC) project. The cost of the 600 MW Kemper plant is projected to increase from $2.2 billion to $6.66 billion, or over four times of the capex cost of an unabated IGCC plant in a similar location[7][8]. In 2015 the US Department of Energy withdrew support for the 200 MW CCS project in Illinois, which has since been cancelled. Due to limited progress to date and the new build and retrofit costs compared to other decarbonisation options, this report assumes that CCS will only be viable in niche applications over the lifetimes of the fossil fuel plants analysed, and thus is not included in this study which focuses on global averages without subsidies.

1.2.4 Impact of carbon prices

The 2016 reference scenario assumes no carbon price, but as of May 2016 there were 40 countries and over 20 cities, states and regions with a carbon price in place[9], including seven of the world's largest 10 economies. Carbon pricing will be one of the levers governments use to decarbonise their electricity sectors in order to meet their Paris COP climate change agreement commitments. In 2017, China plans to implement at national emissions trading system, which will expose another 920 GW

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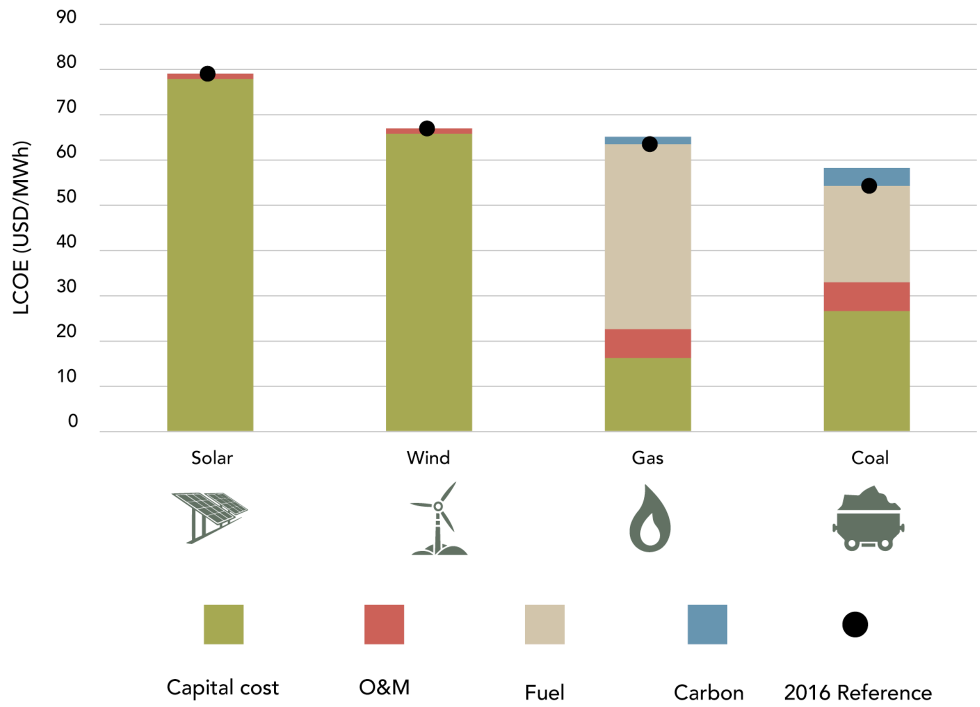
[7] Assumes $2,600/kW based on IEA (2014), World Energy Investment Outlook. Available: http://www.worldenergyoutlook.org/weomodel/investmentcosts/.
[8] MIT (2016), Kemper County IGCC Fact Sheet: Carbon Dioxide Capture and Storage Project. Available: https://sequestration.mit.edu/tools/projects/kemper.html.
[9] World Bank Group; Ecofys (2016), Carbon Pricing Watch 2016. Available: http://www.worldbank.org/en/news/feature/2016/05/25/continuing-momentum-for-putting-a-price-on-carbon-pollution.

of operating coal plant capacity (or 47% of capacity worldwide) to carbon pricing. Although not considered in this analysis, alongside carbon pricing, there are many other air pollution control measures that are in place or being implemented[10], increasing emissions-related costs imposed on fossil fuel generation.

A carbon price, either existing or introduced after an electricity plant is built, imposes a financial penalty on fossil fuel plants, and thus increases their LCOE relative to renewable plants. Figure 9 shows the reference LCOEs with the assumption of a modest carbon price of US$5/t$CO_2$[11], which at the time of writing is within the range of currently enacted carbon prices around the world[12]. The LCOE for gas increases by US$2/MWh and of coal by US$4/MWh.

Figure 9. Impact carbon pricing compared to 2016 reference scenario



Source: see appendix, CTI analysis

1.2.5 Combined impact of updated scenario compared to reference scenario

Combining the above impacts of a lower discount rate for renewables, with shorter lifetimes and lower capacity factors for fossil fuel plants, plus a US$5 carbon price, allows a LCOE comparison under market conditions that may more closely reflect the operational electricity system of today rather than those in the reference scenario. Figure 10 shows that, under a collection of reasonable

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[10] IEA (2016), World Energy Outlook Special Report: Energy and Air Pollution. Available: https://www.iea.org/publications/freepublications/publication/WorldEnergyOutlookSpecialReport2016EnergyandAirPollution.pdf.

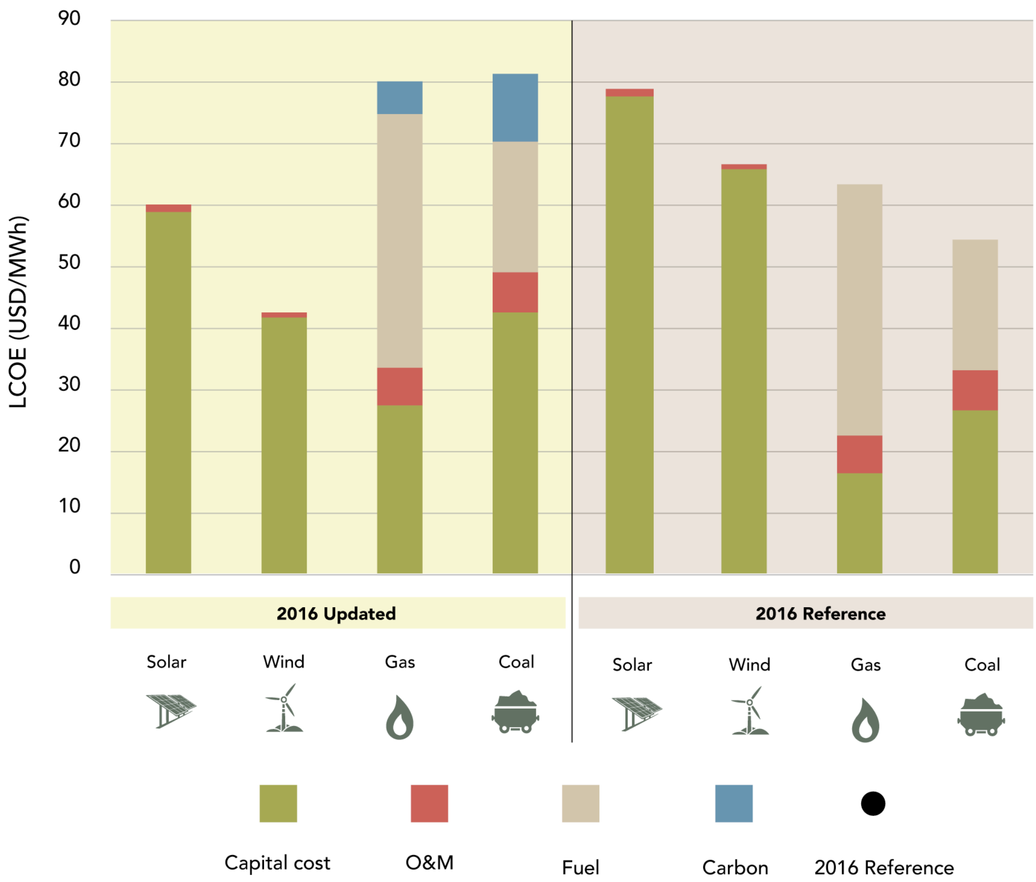
[11] Carbon price assumed to apply for the entire operating lifetime of the plant, in real dollars.

[12] World Bank Group; Ecofys (2016), Carbon Pricing Watch 2016. Available: http://www.worldbank.org/en/news/feature/2016/05/25/continuing-momentum-for-putting-a-price-on-carbon-pollution.

alternate assumptions, the relative order of the reference case is reversed to see renewable plants being the least cost source of generation today[13].

Many of these individual factors are likely to occur together, and reinforce one another, creating a more favourable energy market for renewables. For example, increased renewables deployment leads to reduced capacity factors for fossil fuel plants which lead to shorter lifetimes. Not all the above factors will apply to every power project, but not all factors are necessary and the magnitude of the individual impacts means that if only some of the impacts are present the LCOE balance will likely tip in the favour of renewables technologies. For example, with the other factors in play, it is not essential to have the additional carbon price element on fossil fuels for renewables to come out less expensive.

Figure 10. Updated scenario compared to reference scenario



Source: see appendix, CTI analysis

[13] This report assumes that the costs to the system associated with integrating and balancing intermittent renewable generation are not borne by the individual renewables plant, which is presently the case, in effect being separate from the renewables investment. Market balancing and integration are assumed to be provided by other technologies and investments, and are compensated in the market under current market structures.

1.3 2020 2D pathway scenario

The 2D pathway scenario uses assumptions based on an investment decision made in 2020 in an electricity system that is consistent with keeping global average temperatures to 2D. The 2D pathway scenario includes updated assumptions on (i) the capex costs of renewable energy (ii) the capacity factors for renewable energy plants (iii) the capacity factors for fossil fuel plants (iv) the financing costs of fossil fuels and (v) carbon pricing for fossil plants. The assumptions used in the 2020 2D pathway scenario are detailed in Table 3 and discussed below.

Table 3. Modified assumptions for the 2020 2D pathway scenario

	Solar	Wind	Gas	Coal
Capex (US$/MW)	0.9	1.6	0.9	2
Capacity (MW)	100	100	500	600
Capacity factor (%)	20	40	31	42
Discount rate (%)	8	8	10	10
Carbon price (US$/t)	-	-	10	10

Source: see appendix, CTI analysis

1.3.1 Impact of future capex costs for renewable energy

The fact that costs of renewable plants are decreasing every year is widely acknowledged. These cost decreases can be linked to historical increases in installed capacity of technologies to calculate future cost decreases via the experience curve.

Experience curves, also known as learning curves, are a common and robust tool for forecasting future technology costs. Based on a historical set of data, a relationship is derived that links cost decreases to demand for a product. For every doubling of ‘experience’ there is an identifiable decrease in costs, where the ‘experience’ is gained through the process of manufacturing, building and delivering the product. More experience gives more opportunity to improve and over time, leading to a predictable decrease in costs. For example, each time a solar panel is manufactured, some learning takes place, which leads to cheaper production of the next solar panel.

Many long-term forecasts of energy technology costs are based on experience curves. Based on data dating from 1976 for solar panels and from 1985 for wind turbines, BNEF has calculated that for every doubling in installed capacity[14] there is a learning rate of 26.5% for solar and 9% for wind. Other scenarios and models may use different learning rates which will affect their expectations of cost reductions – or they may not vary them over time at all.

Future costs, based on experience curves, are dependent on the underlying forecasts of demand. In the case of energy technologies, future costs are based on the forecast installation of each technology. Using the solar and wind installed capacity forecasts from BNEF and applying the learning rate to the increase in installed capacity, a future cost decrease can be calculated for the baseline LCOEs in this report. Table 4 shows an average solar plant’s LCOE is 23% lower by 2020 and an average wind plant’s is 5%, highlighting how the energy pathway can have significant impacts on the technology costs in the near future. In addition, lower LCOEs increase the number of projects where renewables are installed, which leads to further cost reductions, creating a virtuous circle.

[14] A widely used proxy for experience in energy technology costs. BNEF (2016), Technology Cost Declines. Available: https://www.bnef.com/core/themes/technology-cost-declines.

Table 4. Learning rate based of solar and wind based on changes in global installed capacity in 2016 and 2020

Technology	Global Installed Capacity 2016 (MW)*	Global Installed Capacity 2020 (MW)*	Increase in Global Installed Capacity 2016-2020	Learning rate	LCOE decrease 2016-2020
Solar	221	426	88%	26.5%	23%
Wind	425	686	53%	9.0%	5%

Source: BNEF (2016), Energy Technology Perspectives (2016)

* Installed capacity figures from IEA's ETP 2016. Figures are total installed capacity which may include some minor retirements.

In addition, as many base case forecasts are policy static, any new policy that leads to an increased installation of a technology will lead to faster cost reductions than the base case. Meaning that the introduction of new policies to drive decarbonisation will further increase cost reductions for renewables above the base case.

1.3.2 Impact of future capacity factors for renewable energy plants

A key determinant of electricity production of a wind and solar plant is how much the wind blows and the sun shines. The site-specific characteristics of the renewable resource varies widely between sites in the same country. When comparing LCOEs it is necessary to know if the insolation or wind speeds assumed reflect an average of all sites in a country, or are specific to a certain location. This information is often not reported with LCOEs. There will likely be technological improvements raising the performance of renewables in the future. For example, MIT researchers recently demonstrated how solar cells can break through a capacity factor of 32% – a theoretically predicted ceiling on how much sunlight they can convert into electricity[15].

A plant's capacity factor, usually presented as a percentage, is calculated as the amount of electricity generated divided by the potential output of the plant were to be operated at 100% capacity. It is a measure of how much of the plant's capacity is used over a certain period. An optimal site for a wind turbine will have higher average wind speeds and winds that blow more often, translating to more electricity generated, and a higher capacity factor for that turbine than one located in a worse position. A higher capacity factor leads to a lower LCOE. Likewise, insolation is a measure of the energy of the sunlight that reaches the earth's surface at a specific location. A site with higher insolation leads to more energy hitting the PV panel, more electricity generated, a higher capacity factor, and a lower LCOE.

The reference case used an average insolation and wind factor for the LCOE calculation; however, if a new project is built in a site with a best-in-country factor there will be an increase in the electricity generated and a lower LCOE. Table 5 shows a range of capacity factors for wind and solar for selected countries. Wind shows a larger distribution of capacity factors and therefore greater potential for outperforming the average level.

[15] MIT (2016), Hot new solar cell. Available: http://news.mit.edu/2016/hot-new-solar-cell-0523.

Table 5. Wind and solar PV capacity factors for selected countries

	Wind Capacity Factor		Solar PV Capacity Factor	
Country	**Country Average**	**Best in Country**	**Country Average**	**Best in Country**
Germany	24%	26%	11%	12%
USA	37%	50%	16%	20%
UK	26%	29%	10%	11%
Japan	22%	30%	14%	16%
Australia	38%	45%	20%	22%
China	25%	31%	16%	18%
India	23%	27%	19%	20%
Brazil	52%	60%	19%	20%

Sources: BNEF H1 2016 PV LCOE Update, BNEF H1 2016 Wind LCOE Update

A generic LCOE for wind or solar masks the fact that there are significant differences in site suitability in each country, and the capacity factor of the best site can lead to a much lower LCOE than an average site. The 2016 reference and updated scenarios assume 18% capacity factor for solar and 30% for wind, while the 2020 2D scenario uses a capacity factor of 20% for solar and 40% for wind.

1.3.3 Impact of future financing costs for fossil fuels

While there are multiple factors that may decrease the cost of capital and discount rate for renewables in the future as these technologies become proven, and parties with lower costs of capital own and operate renewables plants, equally there are factors that are likely to increase the cost of capital and discount rate for fossil fuel plants in the future (see Box 3).

Box 3. Fossil-fuel risk premium

A deteriorating market and operational outlook for a fossil fuel plant can impact an existing plant's economics in various ways. For example, many plants require refurbishments when critical components reach their lifetime or fail, and there may be regular debt refinancing scheduled through the life of the plant. In addition, plants that do reach the end of their life may have the option of undergoing additional investment to extend their life. As market conditions deteriorate, the decision to make further investments in fossil fuel plants with increasing uncertain futures are increasingly likely to be delayed or cancelled. At this point, these plants risk becoming stranded assets.

By 2020, as the current trend of increasing renewables penetrations and global decarbonisation policy, and more cases of decreasing capacity factors and early retirements of fossil fuel plants emerge, increased risk premiums for fossil fuel plant financing could become increasingly commonplace. To investigate the potential impact, the 2016 reference and updated scenarios' assumption of a 9% discount rate for gas and coal plants is increased to 10%, producing an increase in the global average LCOE compared with the 2016 updated scenario of US$2/MWh for gas and US$3/MWh for coal. Equally, fossil fuel risk premiums could apply in the future financing of refurbishments or during scheduled refinancing of existing plants.

1.3.4 Impact of future capacity factors for fossil fuels

An electricity generation system that is transitioning towards being carbon-free will have a high penetration of intermittent renewables - the share of generation from wind and solar in the IEA's 2DS is nearly 40% globally and up to around 50% in some countries by 2050. As outlined above, higher penetrations of renewables are likely to depress the capacity factors of fossil fuel plants as renewables with lower costs are dispatched before fossil fuel plants.

The impact of reduced fossil fuel capacity factors may be minimal in the first few years of a plant's operation, but as the share of renewables increases as the electricity mixes decarbonises, the impact increases over the lifetime of the plant. While the largest impacts are towards the end of a plant's lifetime, once discounted back to a present value they remain significant enough to alter the balance of an LCOE comparison.

The IEA's ETP allows an implied average capacity factor to be calculated from its 2DS, which shows that capacity factors for operating fossil fuel plants decline over the lifetime of the plant as the global electricity system's emissions reduces. These reduced capacity factors in the future can be discounted back[16] to allow a comparison in 2020 under global average assumptions. For a fossil fuel plant constructed in 2020, under a 2 degrees pathway, the capacity factor of a gas plant over its lifetime is 31% and coal is 42%, leading to an increase compared to the 2016 updated scenario's LCOEs of US$7/MWh for gas and US$19/MWh for coal.

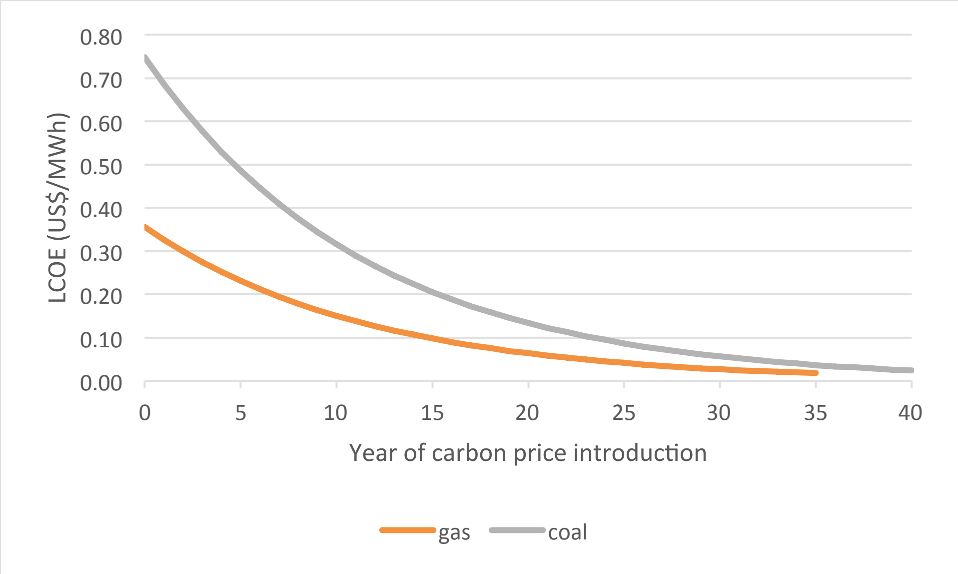
1.3.5 Impact of future carbon pricing

As mentioned above, a carbon price imposes a financial penalty on unabated fossil fuel plants. If that carbon price exists at the first day of a plant's operation the carbon cost should be included in a plant's LCOE. However, the introduction of a carbon price later in the plant's lifetime also imposes a financial penalty on a plant, even after its construction. The expectation of a carbon price being introduced anytime during a plant's lifetime should be included in the plant's cost today. For example, if a plant is built in 2020 and there is an expectation of a carbon price being introduced in 2025, the discounted cashflows of the carbon price from the fifth year of operation onwards should be included in the current LCOE comparison.

To not include a carbon price assumes that at no time during the lifetime of a plant will it operate under a carbon price, which would be an unlikely event in many of the world's energy markets as there is already about 13% of the world's greenhouse gas emissions covered by a carbon price, and there are targets to increase this to 25% by 2020[17]. More than 90 countries included proposals for carbon pricing initiatives in their national plans (the Intended Nationally Determined Contributions), prepared for the Paris climate change agreement. Figure 11 shows that a carbon price of US$10/tCO2 in year 5 of operation imposes a penalty of US$2.3/MWh on the LCOE of gas and US$4.9/MWh on the LCOE of coal.

[16] Using the base line discount rate for gas and coal of 9%.
[17] World Bank Group; Ecofys (2016), Carbon Pricing Watch 2016. Available: http://www.worldbank.org/en/news/feature/2016/05/25/continuing-momentum-for-putting-a-price-on-carbon-pollution.

Figure 11. Increase in fossil fuel plant LCOEs per US$1/t$CO_2$ carbon price by year of introduction after start of plant operation*



Source: CTI analysis

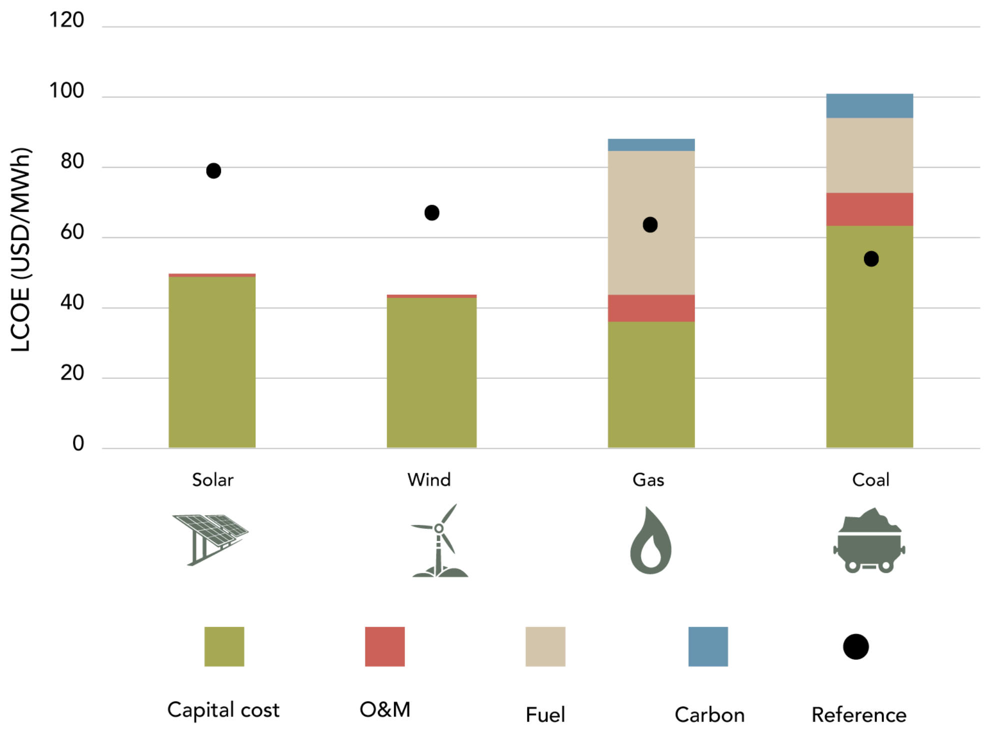
* Assuming the reference assumptions for discount rate, plant efficiency and lifetimes. Carbon price assumed constant in real terms over the lifetime of the plant from the year of introduction.

In addition, to the penalty on fossil fuel plants, a carbon price also benefits renewables plants by increasing the electricity prices that a renewable plant receives. The wholesale electricity price is set by the price of the marginal generator. If that marginal generator is fossil fuelled, the carbon price will be added to the electricity price that the renewables plant receives. A renewables project with a 25-year lifetime will likely benefit from the introduction or increase in the carbon price at some point over its lifetime.

1.3.6 Combined impact of 2D scenario compared to 2016 updated and reference scenarios

Figure 12 shows the impact of the above factors on the global average LCOE in 2020. The impacts are the renewables cost reductions, increased discount rate for fossil fuels, decreased capacity factors for fossil fuels, and the introduction of a modest US$10/t$CO_2$ carbon price. In 2020, under the assumptions outlined above, average solar and wind plants are significantly lower cost than the average gas and coal plants. This analysis suggests that renewables will be more attractive when the investment decisions take into consideration the reality that the energy transition is already underway.

Figure 12 – 2D scenario compared to 2016 updated and reference scenarios*



Source: see appendix, CTI analysis

* capex costs for gas and coal plants are not expected to decrease pre-2020, as these are mature technologies and have minimal scope for additional learnings. The main driver of their LCOE is fuel costs, and the fuel price assumptions used in the reference are assumed to be suitable in 2020.

1.3.7 Conclusion

It is worth reiterating that there are a range of LCOEs for any technology, and global LCOE averages cannot give a definitive answer as to what is the better investment in a specific situation. However, what the global averages with real world 2016 assumptions tell us is that already the average LCOEs for solar and wind are lower than their coal and gas competitors. The 2016 updated and 2020 2D scenarios apply a conservative carbon price of $5/ton and $10, respectively. These carbon price levels and other environmental policies (such as air pollution regulations) may in fact be higher in some regions. Importantly, the LCOEs for wind and solar in the 2016 updated scenario are not dependent on our carbon pricing assumptions to come out lower than coal and gas. It should also be noted that fuel prices for coal ($80/t) and gas ($7/mmbtu) plants could decline significantly in the future, potentially compromising the competitiveness of wind and solar. However, in our 2020 2D scenario it is clear that on average, even very low fuel prices would not tip the advantage back to fossil fuels.

This analysis highlights how a series of modest incremental changes to LCOE assumptions can have a large cumulative impact on the affordability of power generation technologies. Under a different set of input assumptions that align with the current operating environment, renewables are typically more competitive than fossil fuels from a costs basis than traditional analysis shows. This reflects that the energy transition has already started – and that is why an increasing number of renewables projects are already being built in many markets.

An appreciation for the transition currently underway, and accelerating, in global electricity markets requires a rethink of the traditional inputs to electricity plant LCOE comparisons. It is difficult to imagine that in a world of high renewables penetration the long-dated 20-30-40 year investments in fossil fuel plants will be operating under similar market conditions in the future as they were only a few years ago; i.e. assumptions that could be considered industry standard in the past no longer make sense today.

2. Impact of revenues on LCOE

This section gives an example of how electricity prices impact plant economics and how wind and solar are best placed to benefit from grid congestion payments.

2.1 Impact of electricity prices on plant revenues

The LCOE calculation is a representation of an electricity plant's costs, but not its revenue. Omitting half of a plant's economics limits the usefulness of using only the LCOE to compare between technologies. A plant's revenue[18] is based on the electricity price at which it sells its electricity. Electricity prices vary through the day depending on the balance of supply and demand, and on the specific mix of electricity plants in a market. In a competitive electricity market where prices are set by the market in order to balance supply and demand[19], generators bid to supply electricity from their plant at a certain price, where those bids are ordered from lowest price to highest price, and is where the term "merit" order is derived, the generators win the right to generate their electricity up until all demand is met. The price that each generator receives for its electricity is set by the highest priced winning bid.

The specific shape of electricity demand in each market depends on the share of residential demand to commercial and industrial demand, to weather, and to cultural factors that dictate electricity usage patterns. However, in a typical electricity market, demand for electricity and therefore prices are highest during the daylight hours when people are active, using their appliances at home, working in their jobs in industry and commercial sector. Some generators can gain an economic benefit from these increased electricity prices.

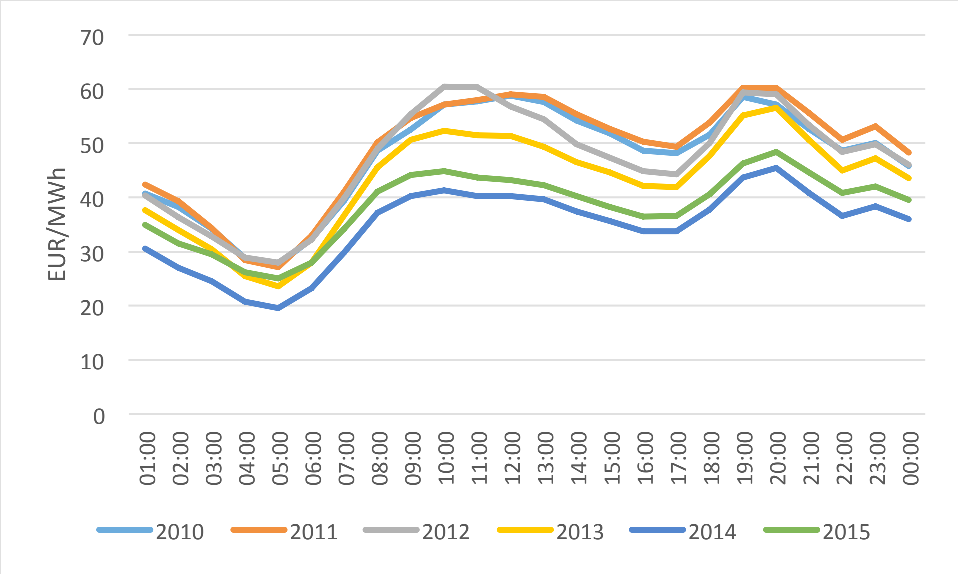
Solar generation is restricted to daylight hours, with generation peaking when the sun is overhead during the middle of the day. Solar generates at a time of day that aligns with the time of highest demand in most electricity markets, and solar receives a higher price than the market average for the electricity it produces[20]. Figure 13 shows the average daytime wholesale electricity prices over the year from 2010 to 2015 in France. The highest prices are clearly seen in 2 periods, between 10am to midday, and from 7pm to 8pm.

[18] Assuming the plant operates in a competitive electricity market and is exposed to the prevailing electricity price, i.e. is merchant exposed and not under contract. An electricity plant whose output is fully contracted receives the contracted price rather than prevailing electricity price.

[19] In regulated electricity markets the government sets the electricity price. Regulated prices can be set higher at times of higher demand in order to compensate higher cost generators.

[20] Assuming the solar plant is exposed to electricity market pricing and does not receive its revenue from a fixed off-take contract.

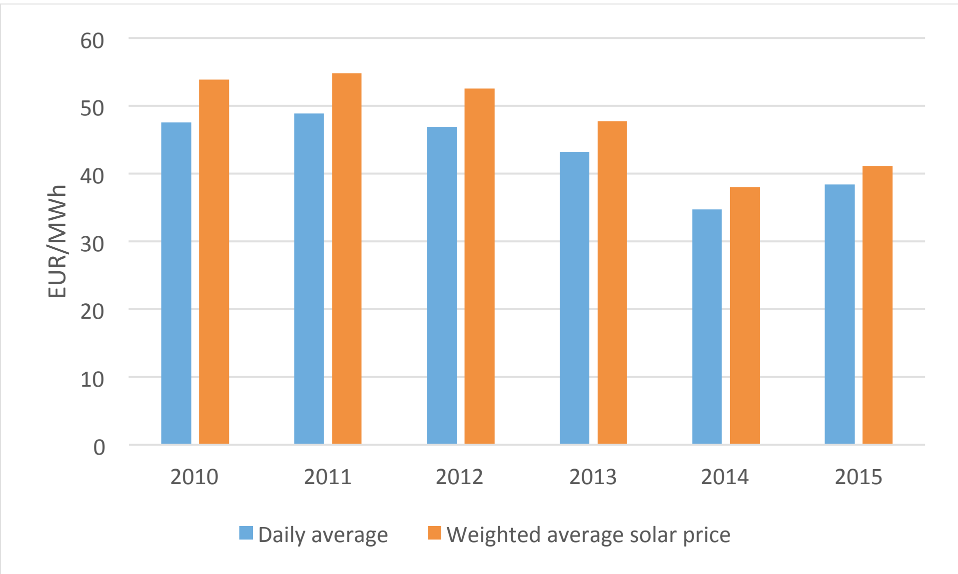
Figure 13. Average daytime wholesale electricity prices in France, 2010 to 2015



Source: Bloomberg New Energy Finance, 2016

Figure 14 compares the average price over the entire day to the weighted average price during the hours of the day when solar produces, showing that solar production aligns with the time of day when electricity prices are higher than the total daytime average. The average of the 6 years analysed is a US$4.76/MWh electricity price, and therefore revenue, benefit for solar compared to a plant that received the average price such as coal as a baseload generator. For context, solar's LCOE in the 2016 reference scenario is US$79.10/MWh, if it receives a US$4.76 electricity price premium, its LCOE equivalent becomes US$74.34/MWh, a 6% reduction.

Figure 14. Average daytime wholesale electricity prices in France, 2010 to 2015[21]



Source: Bloomberg New Energy Finance, 2016

[21] The solar weighted average electricity price is the electricity price weighted by the shape of solar generation, starting around 6am, peaking around midday and stopping around 6pm.

Every electricity plant operates differently, and the average of the electricity prices that it sells its generation for over a year will vary. In general, baseload coal plants will attempt to run for as many hours as possible, and a baseload plant's daily weighted average electricity price it receives will approach the 24-hour average. Mid-merit gas plants will follow demand more closely, and therefore are also likely to receive revenues from above-average electricity prices. Wind is intermittent and its generation profile and thus electricity price revenue is very site specific.

2.2 Impact of grid payments on plant revenues and LCOE

One example of how revenues can be impacted is through grid payments. A new generator, when connected to the electricity network has an impact on how the grid functions, based on the location of its generation relative to the location of demand. The physical infrastructure, the electricity transmission and distribution lines, that link generators to end users, can become congested when there is an excess of generation in one point of the network or an excess of demand. A new generator can either alleviate or aggravate the flow of electricity through a grid and grid congestion. Some grids allow for financial payments to promote efficient grid function. These payments are designed with two main goals: to alleviate grid congestion, and to increase the amount of electricity that reaches consumers by reducing losses and incentivising generation located close to demand.

There are two ways to avoid congestion (i) investing in upgrading the transmission network or (ii) paying generators to locate at specific locations of the grid in order to better balance supply with demand. A reduction in congestion via better location of supply relative to demand can avoid the cost of network upgrades. To avoid congestion some network operators incentivise an optimal location of supply by assigning a financial benefit or penalty to a generator in relation to its location within the network. These financial penalties can be a significant factor in the viability of a type of generator at a specific location. Congestion-related payments exist in many electricity markets around the world, as summarised in Table 6. The functioning and amount of payment is specific to the characteristics of each grid, and depend on the amount of transmission and distribution required between electricity supply (generators) and demand, and the distances between these points.

Table 6. Selected grids & operators with location-related grid payments available to generators

Country	Grid / Grid Operator
Argentina	Compañía Administradora del Mercado Mayorista Eléctrico (CAMMESA)
Australia	National Electricity Market (NEM)/Australian Energy Market Operator (AEMO)
Chile	Comision Nacional de Energia (CNE)
Ireland	Single Electricity Market (SEM)/Single Electricity Market Operator (SEMO)
New Zealand	New Zealand Electricity Market/Electricity Authority (EA)
Singapore	National Electricity Market of Singapore (NEMS) / Energy Market Authority (EMA)
UK	Office of Gas and Electricity Markets (OFGEM)
US – California	California Independent System Operator (CAISO)
US – New England	Independent System Operator New England (ISO-NE)
US – New York	New York Independent System Operator (NYISO)
US - Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.	Eastern Connection - PJM Interconnection
US – Texas	Electricity Reliability Council of Texas (ERCOT)

Source: CAMMESA, AEMO, CNE, SEMO, EA, NEMS, EMA, OFGEM, CAISO, ISO-NE, NYISO Eastern Connection.

Australia's Electricity Market Operator (AEMO) uses one charge to represent both congestion and transmission losses, called a Marginal Loss Factor (MLF). The MLFs published by AEMO are specific to each transmission substation, and indicate a premium or discount to any plant's generation that is connected to that substation. The price that a generator receives for their electricity is multiplied by their MLF applicable to its location, and thereby impacts the revenue that the plant receives. For 2016-17, the MLFs show that an optimal substation plant site in Australia's National Electricity Market (NEM)[22] which receives the maximum MLF benefit is at the regional town of Broken Hill, with an MLF of 1.1632. The substation site with the poorest MLF in Australia is located at the regional town of Mullumbimby, with an MLF of 0.9403. A new plant located at Broken Hill may receive a 16.32% increase in its revenue, whereas a new plant situated at Mullumbimby may receive a 5.97% penalty on its revenue[23].

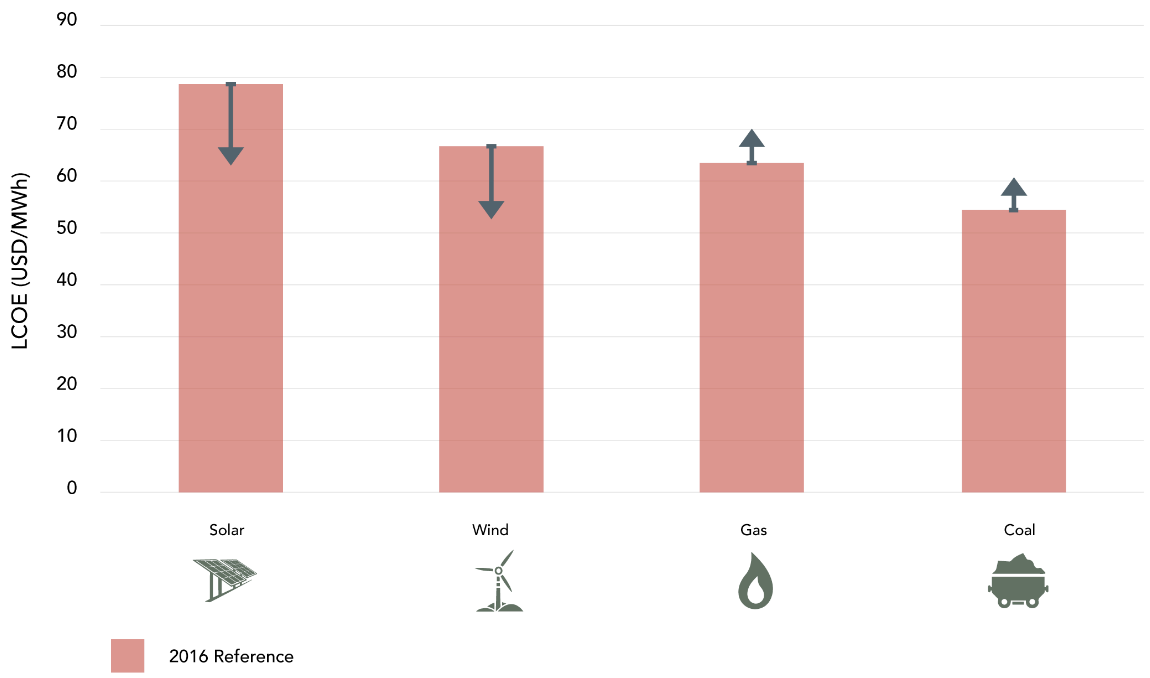
To highlight the significance to a project's overall economics, the grid-related revenues can be weighed against a plant's costs which were previously analysed. The LCOE represents the price at

[22] National Electricity Market covers the states of Queensland, New South Wales, Australian Capital Territory, Victoria, South Australia and Tasmania, covering approximately 80% of Australia's Energy consumption. For more information, see AEMC (2016), National Electricity Market. Available: http://www.aemc.gov.au/Australias-Energy-Market/Markets-Overview/National-electricity-market.

[23] The MLF of a location is recalculated each year as a result of changes in local supply, demand and transmission infrastructure. A published MLF for a site is not the MLF that a plant will receive over the life of its operation, as the MLF may change in the year after a plant's construction due to its own generation and impact on congestion.

which a plant would have to sell its electricity in order to breakeven[24]. Therefore, an increase in a plant's revenue of is equivalent of a decrease in its cost of the equivalent amount. The congestion payment benefit/discount can be represented as an equivalent difference in costs in US$/MWh applied directly to the LCOE. Figure 15 shows the reference LCOEs of the 4 technologies, with bars to indicate the range of LCOEs if the plant was located at the best site (bar below, representing a decrease in costs) and worst sites (bar above, representing an increase in costs). The ranges show that a well-located plant in an electricity market with congestion payments can have a significant economic advantage over a poorly-located plant, sufficient to potentially alter the technology choice.

Figure 15. Congestion payment ranges* compared with 2016 reference scenario



Source: see appendix, CTI analysis

* Calculation of the exact congestion payment a plant receives requires a detailed site-specific study. These ranges are intended to give an indication of the relative size of potential congestion payment to a plant's LCOE, and ignores changes to supply, demand and transmission infrastructure after a plant's construction.

2.3 Conclusion

New renewables plants are more likely to benefit from favourable congestion payments than new fossil fuel plants, as suitable renewable sites are typically more distributed than fossil fuel plant sites. Fossil fuel plants typically have improved economics when they are built at scale at a site that facilitates low-cost fuel supply, which is often next to an existing infrastructure (e.g. a coal mine, coal railway, gas field, or gas pipeline), thereby avoiding the additional investment of building fuel delivery infrastructure. In addition, most electricity systems globally are currently dominated by large shares of existing fossil fuel plants, meaning new renewables plants that are sited away from

[24] NREL (2016), Simple levelised cost of energy calculator documentation. Available: http://www.nrel.gov/analysis/tech_lcoe_documentation.html.

existing fossil plants can benefit from diversifying the geographic location of electricity supply, and are more likely to alleviate grid congestion. A new fossil fuel plant, sited at a location close to existing plants so as to lower its fuel delivery costs, is more likely to aggravate grid congestion.

As generators located far from demand centres transmit their generation to the end-user, they incur losses as energy is lost due to electrical resistance of the wires, which typically vary depending on distances and types of transmission wires. In 2013, globally 8% of electricity generation was lost during transmission and distribution, and 6% in OECD countries[25]. Even in a regulated electricity market, or a market where there are no payments for locational and congestion benefits, there is a system benefit from locating generation close to demand and thereby reducing losses, which as described above is likely to benefit renewables more so than fossil fuel generation.

The impact of electricity price revenue can lead to the case where a more expensive generation technology, on an LCOE basis, is actually a better investment because it receives higher revenue than the average. For example, if either of the factors identified here – peak prices or grid payments – are combined with one of the updated LCOE assumptions analysed above, it would make solar the most profitable investment in the 2016 reference scenario[26].

[25] IEA (2016), Statistics. Available: http://www.iea.org/statistics/statisticssearch/.

[26] It should be noted again that this cost vs revenue evaluation is a simplification, and there are many other considerations that have been omitted which will also influence any investment decision.

3. Other important factors outside the scope of this report

The purpose of this report was to highlight how the global average LCOEs of power technologies can be over or underestimated – and to showcase the competitiveness of solar and wind power under a set of reasonable assumptions. Going forward the challenge for policymakers is no longer whether wind and solar will become competitive with conventional fossil generation, but rather how to continue to promote low carbon investments cost-effectively while also maximising the system value of solar and wind. Although outside the scope of this report, it is important to mention the following factors.

I. **The impact of increased levels of solar and wind on low carbon investments.** Perhaps the most profound impact of renewable energy, apart from being carbon-free electricity, is that it is breaking down the traditional electricity market structure of baseload + mid-merit + peaking plants. The new electricity market structure is likely to be characterised by variable renewable energy + balancing services. As the role of baseload and mid-merit generators changes, so too do their economics as the corresponding capacity factors decrease. This dynamic is having a dramatic impact on revenues for fossil fuel plants in wholesale power markets[27], due to the merit order and the attributes of solar and wind. Continued solar and wind growth could lead to material decreases in wholesale electricity prices during peak consumption hours.[28] The impact of increased levels of zero (or very low) marginal cost solar and wind power fundamentally challenges the notion that low carbon investments in the power sector can be made based solely on wholesale market price structures and a strong carbon price. During the transition to a low carbon power system a carbon price must be complemented with appropriate mechanisms to support low carbon investments.[29,30]

II. **The impact of increased levels of solar and wind on system value.** Grid operators need to manage the spatial and temporal nature of power generation by matching the supply and demand in real time. This is particularly important with solar and wind, which can account for a much larger share in power generation than annual averages suggest. For example, on the 3rd of November 2013 wind power generation in Denmark exceeded the level of power consumption[31], while the share of all renewable energy in consumption for 2013 on average was only 27%[32]. When the penetration of wind and solar remains small (i.e. a few percentage points of the annual power mix) their integration has a limited impact on grid stability and market functionality[33]. However, with increased levels of wind and solar their integration becomes crucially important to minimise system costs and maximise the value of

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27 Liberalised power markets tend to have a competitive pricing setting.
28 Carbon Tracker, (2015), Coal: Caught in the EU Utility Death Spiral. Available: http://www.carbontracker.org/report/eu_utilities/
29 Climate Strategies (2015), What does the European power sector need to decarbonise? The role of the EU ETS & complementary policies post-2020. Available: http://climatestrategies.org/publication/the-role-of-the-euets-and-complementary-tools-for-power-market-decarbonisation/
30 IEA (2015), Re-powering Markets: Market design and regulation during the transition to low-carbon power systems. Available: https://www.iea.org/publications/freepublications/publication/re-powering-markets-market-design-and-regulation-during-the-transition-to-low-carbon-power-systems.html
31 Morris, C (2013), Denmark surpasses 100% wind power, Energy Transition.
32 Eurostat (2016), Share of energy from renewable sources [nrg_ind_335a]. Luxembourg, Eurostat. Available: http://ec.europa.eu/eurostat/statistics-explained/index.php/Energy_from_renewable_sources
33 IEA (2014), The Power of Transformation. Available: https://www.iea.org/publications/freepublications/publication/the-power-of-transformation---wind-sun-and-the-economics-of-flexible-power-systems.html.

power from wind and solar[34]. According to the IEA, the best way to integrate wind and solar is to transform the overall power system through system-friendly deployment, improved operating strategies and investment in additional flexible resources[35]. Flexible resources include better located generation, grid infrastructure, storage and demand side integration. As identified by IEA analysis, by maximising system value policymakers can significantly reduce integration costs and ensure electricity security.

[34] IEA (2016), Next-generation wind and solar power: From cost to value. Available: https://www.iea.org/publications/freepublications/publication/NextGenerationWindandSolarPower.pdf.

[35] IEA (2014), The Power of Transformation. Available: https://www.iea.org/publications/freepublications/publication/the-power-of-transformation---wind-sun-and-the-economics-of-flexible-power-systems.html.

4. Conclusion

This analysis shows how quickly the relative costs of technologies are changing in the energy transition. It demonstrates how important it is to update the underlying assumptions around capital costs, capacity factors and plant lifetimes, and ensure different future scenarios are considered. In isolation these changes may not seem enough, but they are part of a positive feedback loop. As a result the end of the base load signals the end of the road for new coal plants.

The level of disruption this is already causing in some markets is a wake-up call for policymakers and utilities. Rather than continue debating whether renewables are getting cheaper, it is time to adapt to the reality. Looking at global averages it appears solar and wind now have a technology cost advantage over coal and gas. Like a rolling stone they are gathering momentum as the learning curve and greater deployment brings further cost reductions. Even with low carbon prices and low fossil fuel prices, reducing the cost of capital for renewables with high upfront capex is enough to see them come out ahead post-2020.

Checklist for challenging LCOE assumptions

- **Use a starting point which reflects the current reality of operation, not technical specifications**
- **Use dynamic projections to understand how variables such as utilisation rates may change over time**
- **Consider how lifetimes may be shorter than expected given decarbonisation trends**
- **Review how fossil fuel risk premiums may increase the cost of capital for coal and gas**
- **Identify how new business models and lower cost-of-capital project owners and developers can lower the costs for renewables**
- **Ensure the virtuous circle of increased renewables installation and learning rates feeds into capex cost assumptions**
- **Identify other key market factors, e.g. electricity price premiums, grid congestion payments**

Looking at costs alone is only half the equation – with potential for government subsidies, taxes, variable revenues and system costs among the factors that may need to be considered in each market. This creates uncertainty for potential investors. The direction of travel to reduce carbon emissions and improve air quality in most markets suggests that the risk weighting is shifting to the fossil fuel side.

These new market dynamics also create opportunities for investors. The potential growth in energy storage technologies or demand management services to optimise the integration of renewables into the grid is a huge opportunity. It is certainly more appealing than sinking capital into a new coal plant which is unlikely to have as active or as long a life as anticipated, risking exposure to stranded assets.

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Appendix A

Other important LCOE studies

Several LCOE studies have bene done in the past. A list of further reading is provided below covering leading LCOE research and detailed critiques of the metric.

MIT (2011), Comparing the costs of intermittent and dispatchable electricity generating technologies. Available: http://economics.mit.edu/files/6317

Imperial College (Grantham Institute) (2016) The cost of capital and how it affects climate change mitigation investment. Available: https://www.imperial.ac.uk/media/imperial-college/grantham-institute/public/publications/briefing-papers/the-cost-of-capital-and-how-it-affects-climate-change-mitigation-investment-v2-Grantham-BP-15.pdf

International Energy Agency (2015), Projected costs of generating electricity – public presentation. Available: https://www.iea.org/media/presentations/150831_ProjectedCostsOfGeneratingElectricity_Presentation.pdf

Rocky Mountain Institute (2014), Levelized cost of energy: A limited metric. Available: https://www.greenbiz.com/blog/2014/05/21/levelized-cost-energy-metric

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Appendix B

Summary of assumptions for Baseline LCOEs

	Solar	Wind	Gas	Coal
Lifetime (years)	25	25	35	40
Capex (US$/MW)	1.2	1.7	0.9	2
Capacity (MW)	100	100	500	600
Capacity factor (%)	18%	30%	60%	80%
Fixed Opex (US$/MW/year)	20	25	12	30
Variable Opex (US$/MWh/year)	0	0	5	4
Efficiency (%)	100%	100%	58%	46%
Fuel cost (US$/mmbtu)	0	0	US$7/Mmbtu	US$80/t

	Solar	Wind	Gas	Coal
Lifetime (years)	6	6	8	6
Capex (US$/MW)	1	2	8 (based on 3, 5, 6)	8 (based on 3, 5, 6)
Capacity (MW)	8	6	6	6
Capacity factor (%)	1	2	8 (based on 3, 4, 6, 7)	8 (based on 3, 4, 6, 7)
Fixed Opex (US$/MW/year)	1	2	8 (based on 3, 5, 7)	8 (based on 3, 5, 7)
Variable Opex (US$/MWh/year)	1	2	8 (based on 3, 5, 7)	8 (based on 3, 5, 7)
Efficiency (%)	5	5	5	5
Fuel cost (US$/mmbtu)	n.a.	n.a.	9	9

1 - BNEF H1 2016 PV LCOE.
2 - BNEF H1 2016 Wind LCOE.
3 - BNEF H1 2016 Levelised Cost of Electricity Update.
4 - NREL Levelized Cost of Electricity Calculator.
5 - IEA World Energy Outlook 2014.
6 - IEA Projected Costs of Generating Electricity 2015.
7 - Lazard Levelized Cost of Energy Analysis Version 9.0.
8 – CTI analysis based on above sources, generally assuming a midpoint between available sources when broken down to country level in order to arrive at a global average.
9 – Fuel price assumptions based on CTI analysis, assuming use of imported fuels based on globally traded coal and gas prices and including associated transportation costs.