

LEVELISED COST OF ELECTRICITY

DFID 28 priority countries

6 November 2015

Peer-review paper to accompany the main study prepared by Bloomberg New Energy Finance:

Seb Henbest

Luke Mills

Itamar Orlandi

Adel Serhal

Rohit Pathania



This material has been funded by UK aid from the UK government; however the views expressed do not necessarily reflect the UK government's official policies.

ABOUT BLOOMBERG NEW ENERGY FINANCE

Bloomberg New Energy Finance (BNEF) provides unique analysis, tools and data for decision makers driving change in the energy system. With unrivalled depth and breadth, we help clients stay on top of developments across the energy spectrum from our comprehensive web-based platform. BNEF has 200 staff based in London, New York, Beijing, Cape Town, Hong Kong, Munich, New Delhi, San Francisco, São Paulo, Singapore, Sydney, Tokyo, Washington D.C., and Zurich.

New Energy Finance Limited was acquired by Bloomberg L.P. in December 2009, and its services and products are now owned and distributed by Bloomberg Finance L.P., except that Bloomberg L.P. and its subsidiaries (BLP) distribute these products in Argentina, Bermuda, China, India, Japan, and Korea. For more information on Bloomberg New Energy Finance: <http://about.bnef.com>, or contact us at sales.bnef@bloomberg.net for more information on our services.

ABOUT BLOOMBERG

Bloomberg, the global business and financial information and news leader, gives influential decision makers a critical edge by connecting them to a dynamic network of information, people and ideas. The company's strength – delivering data, news and analytics through innovative technology, quickly and accurately – is at the core of the Bloomberg Professional service, which provides real time financial information to more than 325,000 subscribers globally. For more information, visit <http://www.bloomberg.com/company/> or [request a demo](#).

ABSTRACT

The levelised cost of electricity (LCOE) is a common metric for comparing power generating technologies. We assess the LCOE for the UK Department of International Development's (DFID) 28 priority countries using a life-cycle project finance model, building country- and technology-specific input data for capital, operational and finance costs, according to data availability. This analysis suggests that new utility-scale wind and solar PV are, in most cases, more expensive than coal and gas-fired power in DFID's 28 priority countries. This is mainly due to a lack of experience in developing, building and financing renewable projects. While wind and solar technology will continue to get cheaper with technology innovation in manufacturing, further deployment is critical to build supply chains, reduce balance of plant and operating costs, and put downward pressure on technology and counterparty risk that currently results in high costs for commercial finance.

INTRODUCTION

The levelised cost of electricity (LCOE) allows for direct comparison of the dollar per megawatt-hour, life-cycle cost of different power generating technologies. In financial terms, the LCOE is the long-term offtake price needed to achieve a required equity hurdle rate for a new power generation project. For a project developer, the LCOE is equivalent to the wholesale power price needed at commissioning to cover all project costs (excluding grid connection) and achieve a required equity return rate on the project, in the absence of subsidies.

The UK Department for International Development (DFID) has commissioned Bloomberg New Energy Finance (BNEF) to provide information on the full lifecycle cost of a range of utility-scale electricity generation technologies to help it support developing countries in determining the most sustainable and affordable energy pathways for growth, to improve energy access and to give private sector investors visibility of potential future opportunities.

To meet this need, BNEF has examined levelised costs of electricity (LCOE) for major generation technologies across DFID's 28 priority countries. These countries are: Afghanistan, Occupied Palestinian Territories, Yemen, Democratic Republic of Congo, Ethiopia, Ghana, Liberia, Malawi, Mozambique, Kenya, Nigeria, Rwanda, Sierra Leone, Somalia, Sudan, South Africa, South Sudan, Tanzania, Uganda, Zambia, Zimbabwe, Bangladesh, Kyrgyzstan, Nepal, Tajikistan, Pakistan, Burma and India.

The LCOEs shown in this report reflect the cost of building (capital costs), operating, and financing, new power plants. Capital costs include equipment (eg. gas turbines, wind towers, solar modules), construction costs (eg. foundations, facilities, security, on site electrical), and pre-construction costs (eg. permitting, application, siting and land). Operating and maintenance costs (O&M) can be fixed or variable. Fixed O&M includes administration, contract costs, insurance and wages. Variable O&M costs vary with the level of production and include fuel, carbon, and maintenance. Financing costs cover the cost of debt and

equity. Debt costs include annual principal repayment along with interest. Equity costs are calculated as an annual required return as a percent of the total equity invested. LCOEs do not take account of grid connection and transmission costs, as the standard assumption is that all technologies must pay equivalent connection costs.¹ These LCOEs also exclude direct government subsidies and incentives, any costs that might be associated with balancing variable renewable energy generation, as well as externalities such as pollution, destruction of local habitats and any social costs that may arise from building or operating the plants. However they include conventional taxes such as corporation tax.

METHOD

Bloomberg New Energy Finance calculates LCOEs using its project valuation model – EPVAL (Energy Project Asset Valuation Model).ⁱⁱ EPVAL is a project finance model that captures the timing of cash flows, development and construction costs, multiple stages of financing, interest and tax implications of long-term debt instruments and depreciation, among other drivers.

LCOEs are calculated assuming a development timeline from today. The LCOE is stated at the commissioning date and is then inflated each year to reflect the fact that project revenues are typically inflation-linked.

Coverage

This study covers six utility-scale technologies: pulverised coal-fired power plants fuelled by either hard, sub-bituminous or lignite coal; combined-cycle natural gas (CCGT); onshore wind above 1MW, solar PV above 1MW; binary cycle geothermal; wood pellet biomass incineration; small hydro up to 50MW; and parabolic-trough solar thermal.

Large hydro above 50MW is excluded from this study as it does not lend itself to cost comparison analysis of this type. This is because large hydro costs are affected by local geology, site accessibility, government support and environmental factors such as up-stream and down stream flow issues and flooding. These projects are also not deployable on a standard time-frame and have a range of development, build and operating lifetimes.

This study also does not include solar PV under 1MW. Within established grid systems these small-scale installations generally compete with retail and commercial tariffs, not wholesale prices and other utility-scale plant. In the case of off-grid or micro-grid connected small solar, a comparison would require assessment of grid build-out and connection costs which a standard LCOE analysis doesn't require.

In general, utility-scale solar PV capex is 28% cheaper than small solar PV due to economies of scale.ⁱⁱⁱ

Although we have calculated LCOEs for most of the major generation technologies across the 28 priority countries, there are instances where we consider a particular technology unfeasible.

Wind, solar, small hydro and biomass technologies are deemed deployable in all countries so have full coverage. However coal, gas and geothermal are only considered for countries that either have existing installed capacity, or have reserves that could be utilised in the future.^{iv} The LCOE for solar thermal technology has only been calculated for South Africa and India where there is already commissioned capacity, due to its relatively high cost.^v The coverage matrix is shown in Table 1.

Data Inputs

The lack of project experience in many of the 28 focus countries in this study means a “three option” approach to input data collection was required.

Where available, data has been collected from disclosed project information, third-party research and institutional datasets (Option 1). Where raw data is unavailable for a particular technology and country, we created local estimates by applying relevant land & labour, purchasing power parity and country risk differentials to regional or technology-level benchmarks (Option 2). In particularly difficult cases where no primary data is available and no reliable macro indexes can be applied to extrapolate the data, we revert to using figures derived via either Option 1 or Option 2 for a comparable country.

Non-cost data collected includes heat rates and capacity factors, as well as construction and operating life estimates.

Table 1: Coverage

Country	CCGT	Coal	Biomass Incineration	Geothermal Binary	Solar Thermal	Solar PV	Wind Onshore	Small Hydro
Afghanistan	✓	✓	✓			✓	✓	✓
Bangladesh	✓	✓	✓			✓	✓	✓
Burma	✓	✓	✓	✓		✓	✓	✓
DRC	✓	✓	✓			✓	✓	✓
Ethiopia	✓		✓	✓		✓	✓	✓
Ghana	✓		✓	✓		✓	✓	✓
India	✓	✓	✓	✓	✓	✓	✓	✓
Kenya	✓		✓	✓		✓	✓	✓
Kyrgyzstan	✓	✓	✓			✓	✓	✓
Liberia			✓			✓	✓	✓
Malawi		✓	✓	✓		✓	✓	✓
Mozambique	✓	✓	✓	✓		✓	✓	✓
Nepal		✓	✓			✓	✓	✓
Nigeria	✓	✓	✓			✓	✓	✓

Country	CCGT	Coal	Biomass Incineration	Geothermal Binary	Solar Thermal	Solar PV	Wind Onshore	Small Hydro
Palestine	✓		✓			✓	✓	✓
Pakistan	✓	✓	✓	✓		✓	✓	✓
Rwanda	✓		✓			✓	✓	✓
Sierra Leone			✓			✓	✓	✓
Somalia	✓		✓			✓	✓	✓
South Africa	✓	✓	✓	✓	✓	✓	✓	✓
South Sudan	✓		✓			✓	✓	✓
Sudan	✓		✓			✓	✓	✓
Tajikistan	✓	✓	✓			✓	✓	✓
Tanzania	✓	✓	✓	✓		✓	✓	✓
Uganda	✓		✓			✓	✓	✓
Yemen	✓		✓			✓	✓	✓
Zambia		✓	✓	✓		✓	✓	✓
Zimbabwe		✓	✓			✓	✓	✓

Capex

Capex figures are obtained, where available, through BNEF proprietary or publicly available data sets. These figures are then adjusted to 2015 US dollars. For solar PV and onshore wind, an additional technology-specific discount is applied to reflect cost reductions over time in line with established technology learning curves. For solar PV, we assume a 16% decrease in system costs for every doubling of capacity. This figure stands at 14% for onshore wind. We also assume that wind and solar

installed capacity double every two years, resulting in 7% and 8% yearly learning rates for onshore wind and solar PV, respectively. Capex figures for coal, gas, biomass, small hydro, geothermal, and solar thermal are adjusted at a 2% inflation rate.

In instances when capex data is unavailable for a given country and/or technology, we created local estimates by using capex for a comparable country, and adjusting the balance of plant component for labour, land, and purchasing power parity using the following formula:

$$[\text{capex}]_{\text{extrapolated from } i} = [\text{development costs}]_i + 85\% * [\text{balance of plant}]_i + 15\% * [\text{balance of plant adjusted for land (5\%), labour (5\%) and PPP (5\%)}] + [\text{equipment costs}]$$

Operations & maintenance

Like capex, O&M figures are obtained, where available, through BNEF proprietary or publicly available data sets. In instances when O&M data is unavailable for a given country and/or technology, we create local estimates for fixed and variable O&M by adjusting benchmark O&M costs for labour, land, and purchasing power parity using the following formula:

$$[\text{fixed O\&M}]_j = 85\% * [\text{fixed O\&M}]_i + 15\% * [\text{fixed O\&M}_i \text{ adjusted for land, labour and PPP}]$$

$$[\text{variable O\&M}]_j = 90\% * [\text{variable O\&M}]_i + 10\% * [\text{variable O\&M}_i \text{ adjusted for labour and PPP}]$$

Cost of Finance

Many of the countries in this study suffer from volatile currency regimes, high inflation environments and underdeveloped domestic capital markets. As a further practical constraint, data on local debt costs and return expectations is incredibly scarce. Most project investments in the

countries in question are likely to be supported and/or funded by international players, in addition to local developers.

We have, therefore, modelled LCOEs from the point of view of an international investor seeking to invest \$US and receive \$US returns. All cost inputs that were originally in local currencies were translated into \$US at current exchange rates. We then assume debt is raised in \$US at a rate equivalent to the rate available to US investors plus default and country risk premiums for specific markets, derived from market rates where possible. We have followed a similar approach for required equity returns, which are based on equity returns observed in the US plus premiums that compensate investors for taking on exposure to the different emerging economies. This methodology results in an estimated commercial debt rate based on risk premiums observed in the market. In reality, developers may receive access to lower debt rates through concessional financing, which is designed to de-risk the market-based risk premiums.

We assume inflation to be the same as in the US. This is because local-currency inflation rates in most countries covered in the study are likely to exceed US rates substantially. We assume that power-purchasing parity will hold, so that the value of the local currency will depreciate to keep the USD value of foreign currency unchanged.

Debt and equity finance costs vary across countries and technologies depending on country risk, the perceived reliability of each technology type and experience. In countries assigned a particularly high value for country risk, such as Afghanistan, South Sudan, Palestine, Yemen and Somalia, bank (debt) financing is assumed not to be available.

The cost of debt for a technology in a particular country is built up using the following formula:

$$\begin{aligned} \text{[required rate of return]} &= \text{[real risk-free rate]} + \text{[technology risk premium]} + \\ &\text{[company risk premium]} + \text{[project risk premium]} + \text{[inflation premium]} + \\ &\text{[country risk premium]} \end{aligned}$$

The required rate of return is the nominal rate of return that an investor needs in order to make an investment worthwhile; the real risk-free rate is equivalent, in our case (USD finance), to a risk-free US 12-year (term length) bond yield.

The technology risk premium reflects the risk of lower revenues if a particular technology fails or operates less than anticipated. This generally varies with equipment quality, and maturity of the technology. The company risk premium reflects the risk associated with the project developer going bankrupt. The project risk premium reflects risks associated with a specific project defaulting. We assume a fixed 2% company + project risk premium, and a risk premium per technology as shown in Table 2.

Table 2: Technology risk premium assumptions

Technology	Risk Premium (bps)
Utility Scale Solar PV	200
Onshore Wind	150
Geothermal	300
Small Hydro	150
Biomass - Incineration	200
CCGT	100
Coal Plant	100
Solar Thermal	300

The inflation premium in this calculation is set at 0 because the model assumes USD financing. To calculate the country risk premium, typical default spreads for each country rating class are calculated by averaging CDS spreads and sovereign US\$ bond spreads by ratings class, at the start of every year. The spreads per ratings class reflect the country risk premium. Countries that do not have a sovereign rating are grouped and benchmarked according to their Political Risk Service (PRS) Group score.

Table 3: Country risk premium

Rating	Country risk premium (bps)	Rating	Country risk premium (bps)
Aaa	0	Ba1	250
Aa1	40	Ba2	300
Aa2	50	Ba3	360
Aa3	60	B1	450
A1	70	B2	550
A2	85	B3	650
A3	120	Caa1	750
Baa1	160	Caa2	900
Baa2	190	Caa3	1000
Baa3	220		

The equity hurdle rate build-up methodology assumes an equity premium of 3% over the cost of debt. This reflects the average equity premium seen in similar markets, under the same conditions.

For each country, we apply the standard local corporate tax rate and an inflation rate equal to the International Monetary Fund's forecast US CPI rate, extrapolating the rate out to 2060 according to the previous five year average.

Fuel prices

There are no publicly quoted fuel price indexes for the majority of the countries assessed in this study. Fuel price curves have therefore been constructed using a "benchmark plus transport" methodology that assumes domestic fuel prices are set by the relevant international price indicator, plus cost for seaborne and/or overland shipping.

For coastal countries the spot coal price is set by the regional price indicator plus a 4% seaborne transportation premium. For inland countries the spot coal price is set by the regional indicator plus a 4% seaborne transportation premium and an 8% overland transportation premium. These spot coal prices are then inflated at US-inflation rate to 2060.

The coal price indicator is set based on location and type of coal. The Indonesian Coal Index is used for Asian countries that use sub-bituminous coal. Newcastle Coal (Australia) is used for Asian countries that use hard coal. Richards Bay Coal (South Africa) is used as a coal price indicator for African countries that use sub-bituminous coal. And Nigerian Lignite is used for African countries that burn lignite.

Gas prices are calculated using the same “benchmark plus transport” methodology as coal, but with a single gas price indicator. This is the BNEF LNG price forecast to 2030 (which includes shipping).^{vi} Prices from 2030 are inflated using US inflation rates. India is the only country for which we use a different benchmark gas price.

There are currently no carbon price mechanisms in place in any of the DFID priority countries. Should they be introduced, these costs would be applied as a variable cost per MWh and would act to increase the final LCOE.

Capacity Factors

The capacity factors represents the total generation of a plant as a proportion of its nameplate capacity.

Solar PV capacity factors are modelled using solar GIS data, and assuming a crystalline silicone module with a free-standing mounting position, an optimised module inclination depending on location, and 14% system loss estimation. Although the capacity factor does vary with latitude, country averages are used.

Onshore wind capacity factors are modelled using Bloomberg New Energy Finance’s Wind Farm Capacity Factor Tool (WCFT)^{vii}. Measurements are performed assuming a standard General Electric 2.75MW turbine with an 85-metre hub height and 103-metre rotor. Although the capacity factor for wind does vary within a country based on geography, we have used country averages in the LCOE calculations.

Figure 1: Coal price assumptions (\$/MMBtu, nominal)

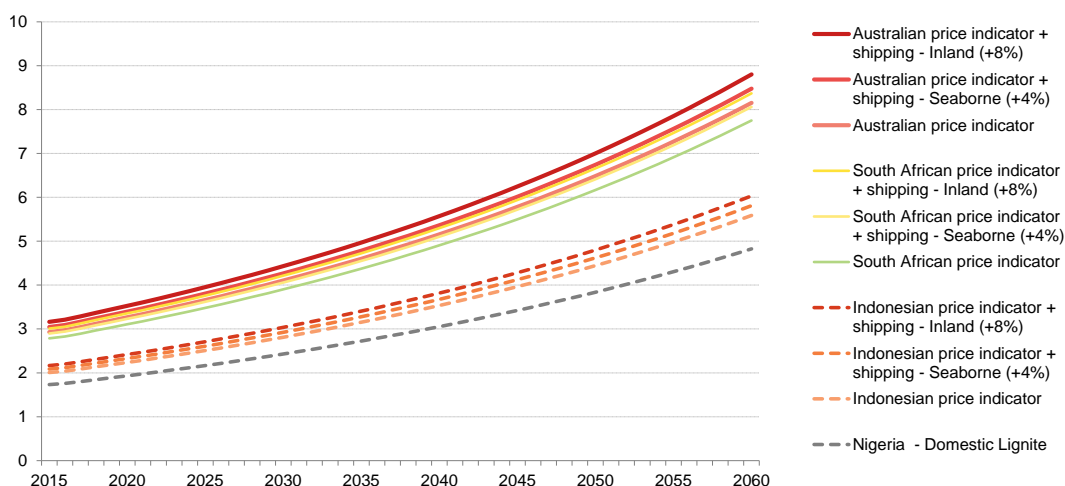
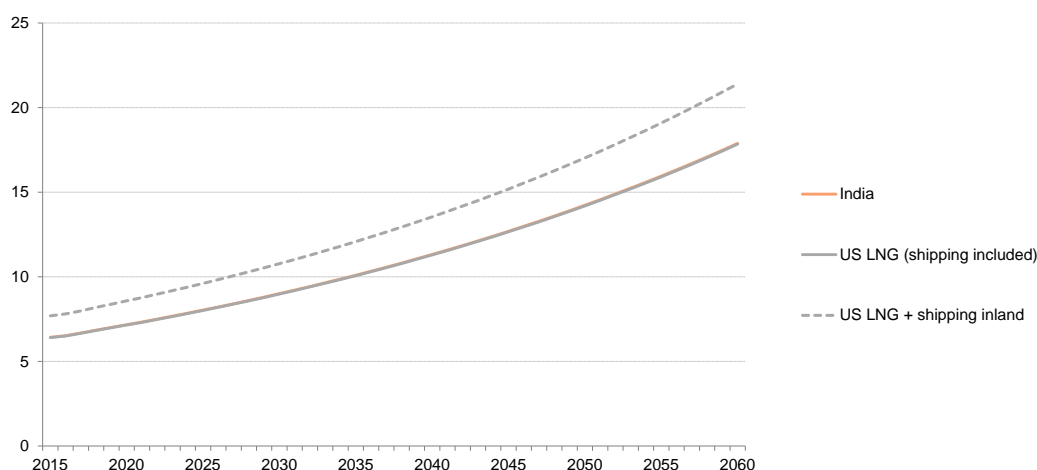


Figure 2: Gas price assumptions (\$/MMBtu, nominal)



For the remaining technologies of coal, gas, biomass, small hydro, geothermal, and solar thermal, capacity factors are obtained from publicly available resources.

In instances when capacity factor data is unavailable for a given country and/or technology, then a generalised technology-specific capacity factor is allocated.

RESULTS

Since cost components vary from project to project, the calculated LCOEs are presented here as a range. The bottom end of the range includes publicly quoted all-in project costs where available. Otherwise these ranges are constructed by varying capex and capacity factors by $\pm 10\%$.

The analysis suggests that new utility-scale wind and solar PV are generally more expensive than coal and gas-fired power in DFID's 28 priority countries. This is mainly due to a lack of experience in developing, constructing and financing renewable energy projects, and the lack of established supply chains, all of which drive up lifetime costs.

Small hydro (<50MW) and biomass are often the lowest cost most technology options. However the potential can be limited by resource availability, geography and available feedstock.

India and South Africa have the lowest-cost new solar PV at \$97/MWh and \$115/MWh respectively. Solar in India has high capacity factors of around 19% and relatively low all-in capex of around \$1m/MW. In recent auctions developers have bid as low as \$64/MWh. However, to generate at this price projects must either be loss-leaders, or have access to particularly cheap financing.

South Africa has excellent solar resource with an average capacity factor of around 21%, but this is offset by higher capital costs. Like India, recent bids have come in low, some as low as \$60/MWh for a 20-year term.

However, with a grace period of up to four years and possibility of a currency rebound, we believe these power purchase agreements (PPAs) do not represent the LCOE for projects that will begin development today. The average cost of new utility-scale solar PV is also likely to be under \$200/MWh in Pakistan, Myanmar, Yemen, Ethiopia, Uganda and Zimbabwe.

Figure 3: LCOE biomass, \$/MWH nominal

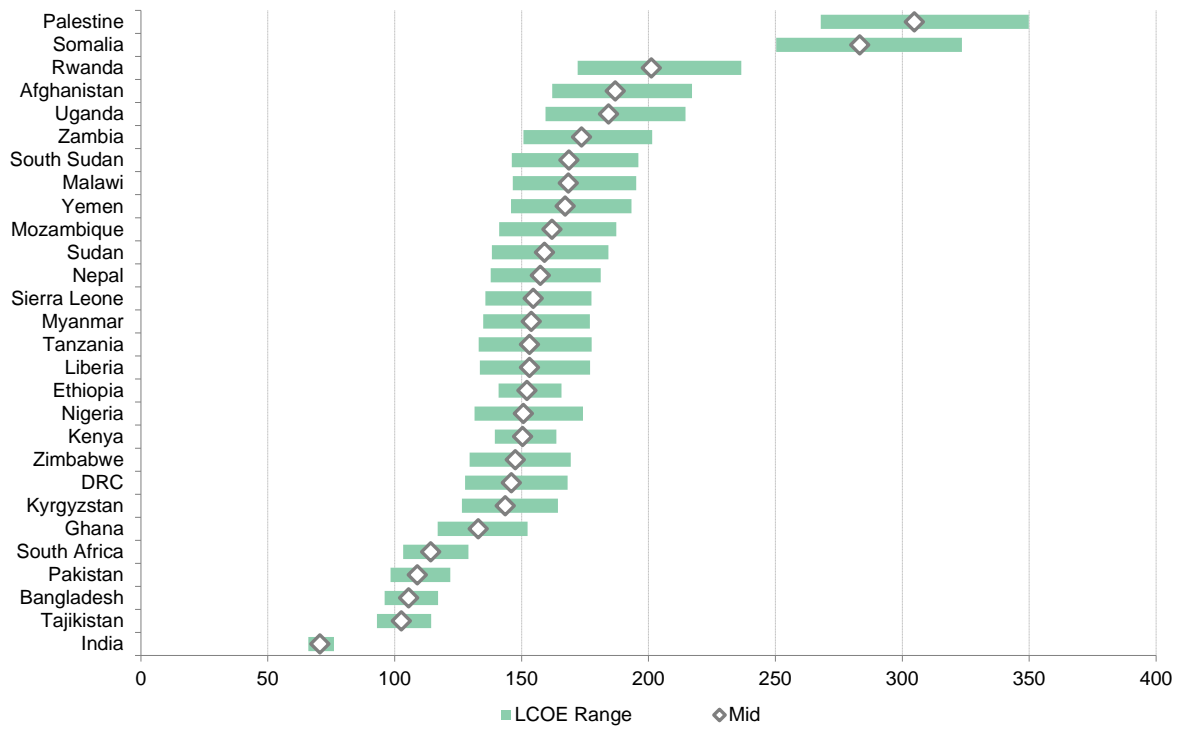


Figure 4: LCOE small hydro, \$/MWH nominal

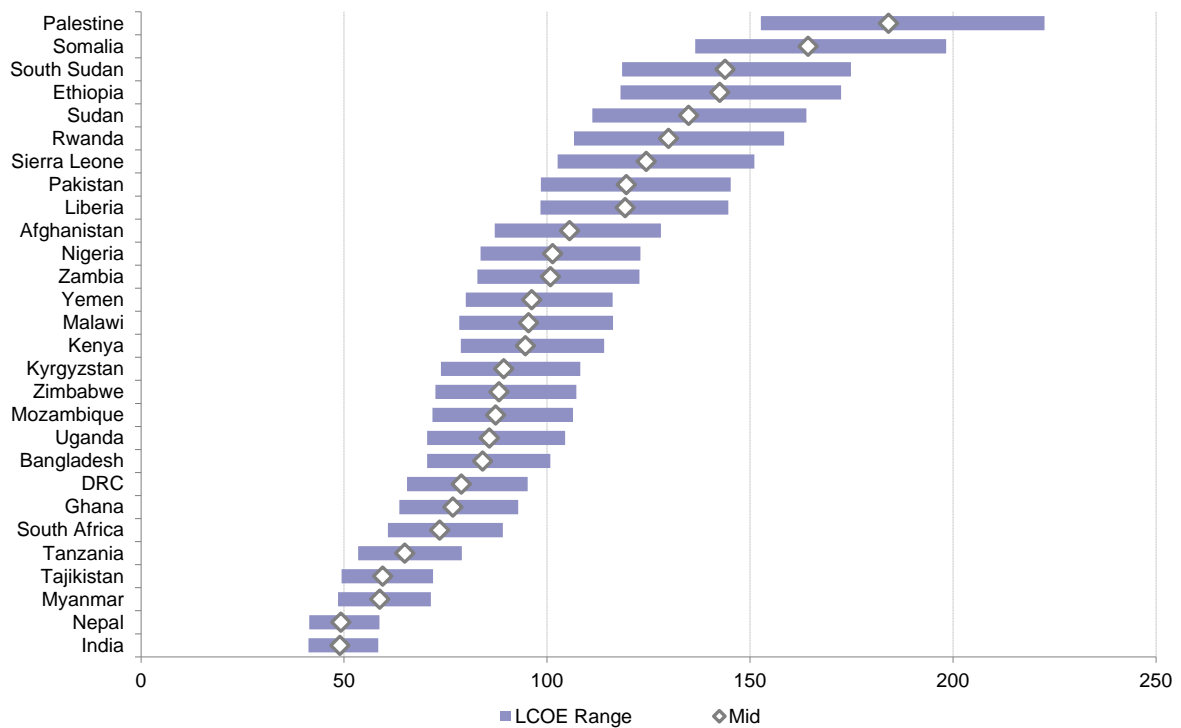


Figure 5: LCOE solar PV, \$/MWH nominal

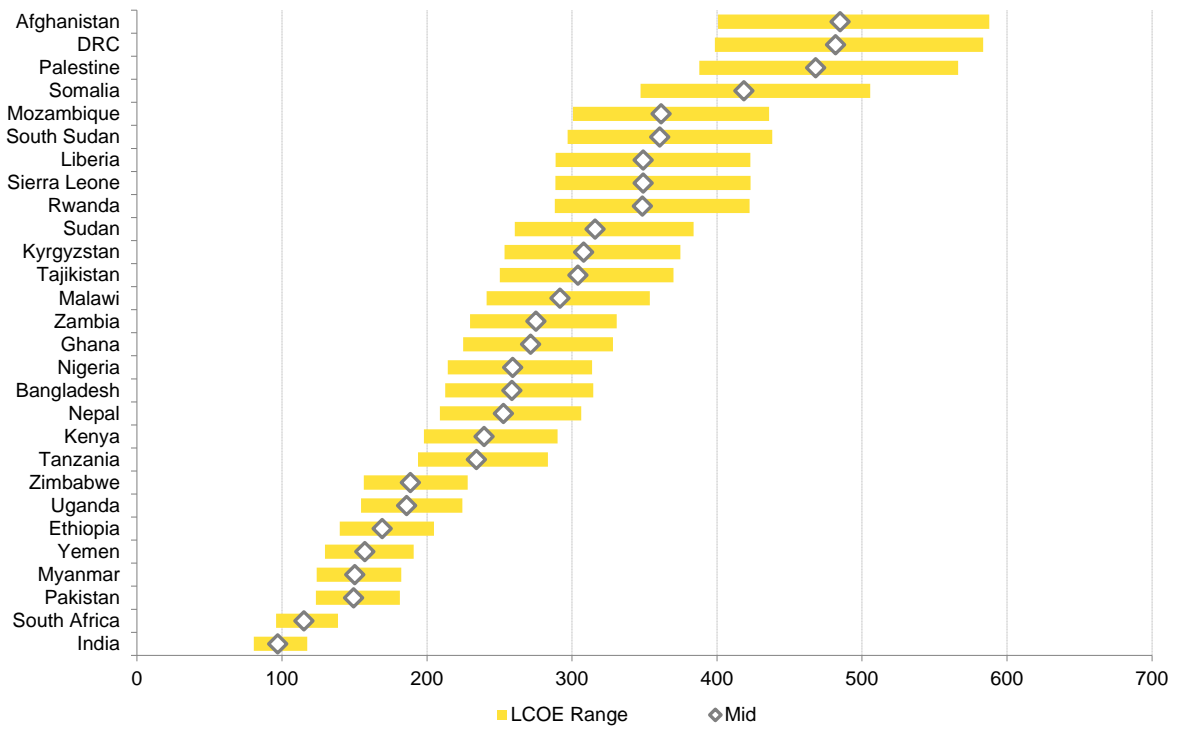
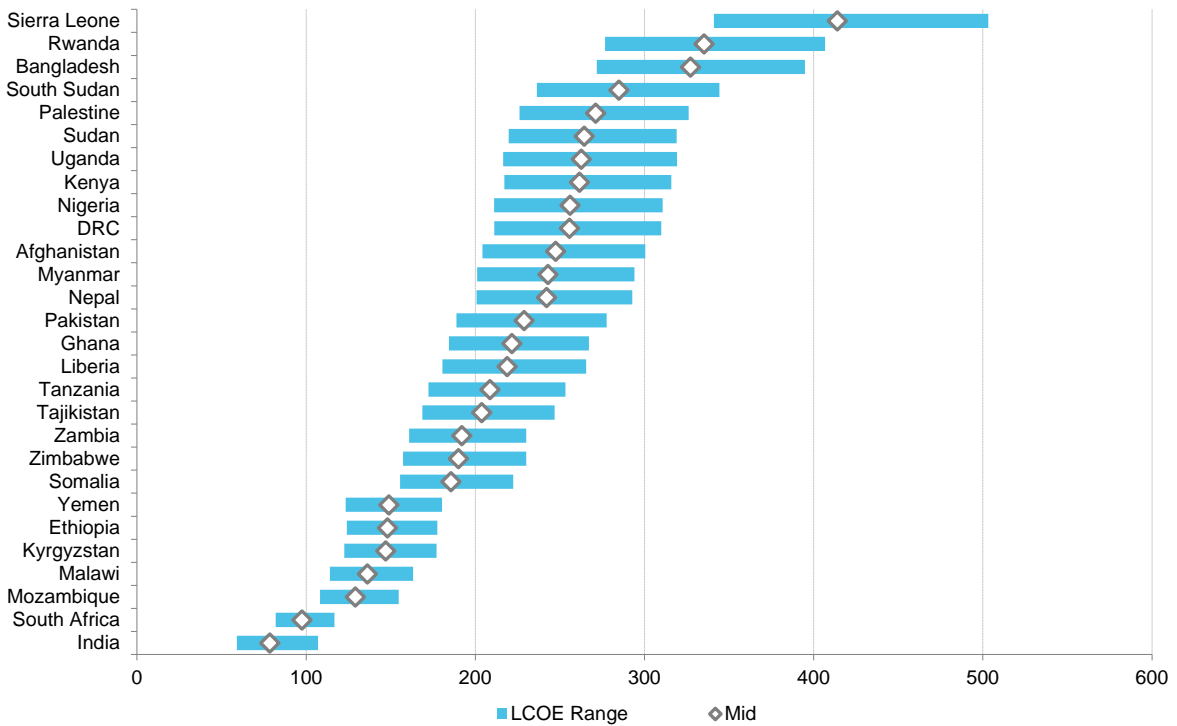


Figure 6: LCOE onshore wind, \$/MWH nominal



The LCOE of new onshore wind is likely to be under \$150/MWh in Mozambique, Malawi, Yemen, Kyrgyzstan and Ethiopia. In Mozambique, for example, the cost of an average wind project is around \$129/MWh, assuming an all-in capex of around \$1.25m/MW and average capacity factor of 22%. Again, India and South Africa appear to have the cheapest new onshore wind at \$79/MWh and \$98/MWh. With plenty of prior construction experience, wind is one of the cheaper technology options for India and, at the highest wind speed sites, is competitive with new coal. The average capacity factor for onshore wind in South Africa is around 30%, making it competitive with new gas- and coal-fired power at high wind speed sites. In contrast, the cost of new wind in Bangladesh and Rwanda can be more than \$300/MWh, and in Sierra Leone more than \$400/MWh due to poor wind resources.

Nigeria, South Africa, Myanmar and India have the lowest cost new gas-fired capacity. In Nigeria, natural gas is likely to be around \$80/MWh as the country has plenty of experience with this technology, resulting in reduced capex and financing costs. It also has rising electricity demand, which means gas plants run at very high capacity factors (>90%). This is common in other countries, such as Pakistan, where demand for electricity exceeds supply and power shortages are often experienced. Some of the cheapest new coal-fired electricity in the world can be built in India, where we estimate an average LCOE of around \$48/MWh. This is due to very low capex and fixed O&M costs, as well as cheap domestic fuel. Of the countries with access to coal supply; Malawi, Kyrgyzstan, Tajikistan, South Africa, Myanmar and Bangladesh, all have LCOEs under \$80/MWh.

India and South Africa are the only two of DFID's priority countries to have deployed solar thermal to date. This technology is generally more expensive than other renewables due to high installation costs. In India it has an LCOE of \$115/MWh and in South Africa, \$168/MWh. However it continues to be deployed in very small volume to take advantage of its thermal inertia and potential for storage which can help meet evening peak demand.

The east coast of Africa, and also India, Pakistan and Myanmar have geothermal resources that can be exploited for power generation. The

estimate LCOE is lowest in Myanmar at \$86/MWh and highest in Pakistan at \$168/MWh.

Figure 7: LCOE natural gas CCGT, \$/MWh nominal

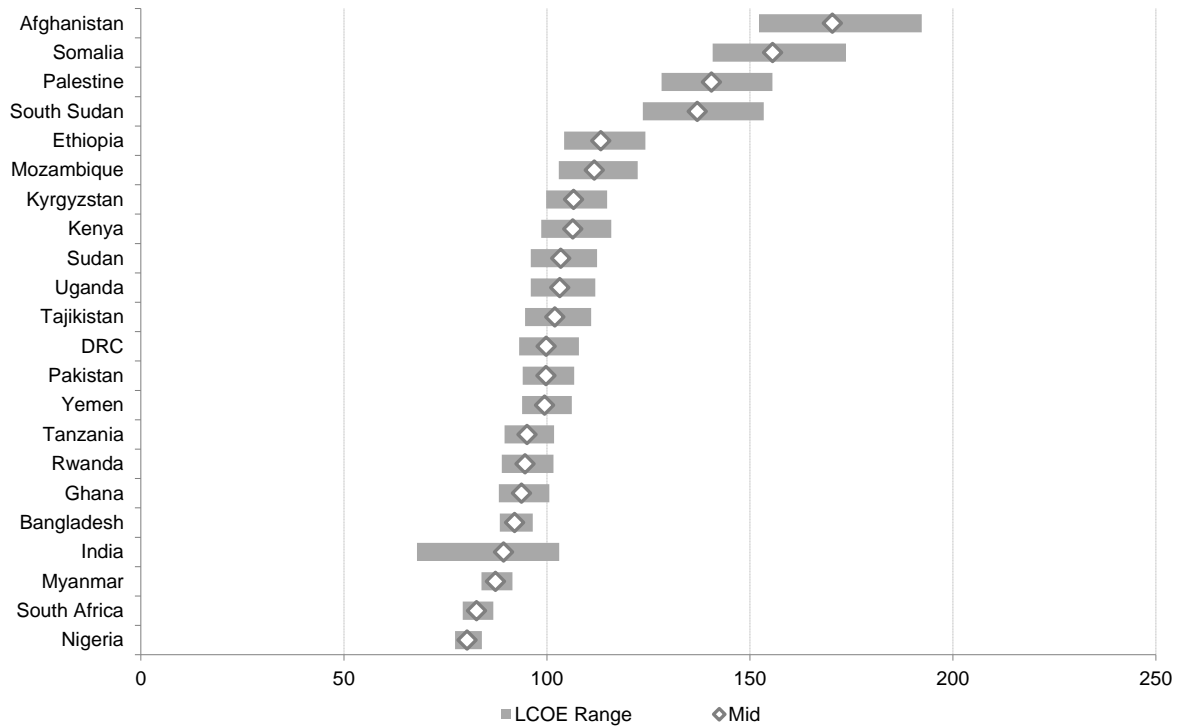
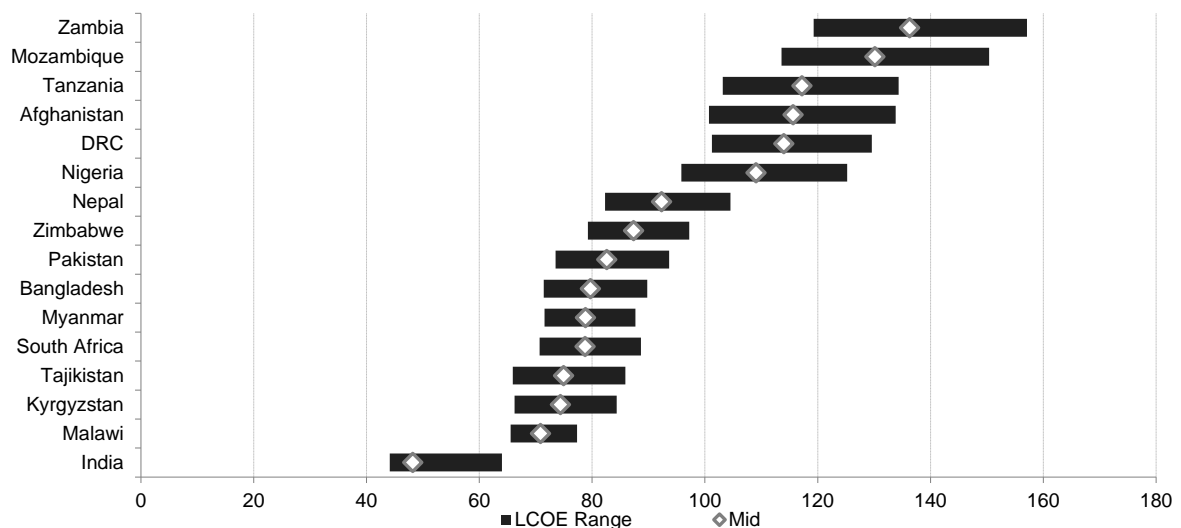


Figure 8: LCOE coal, \$/MWh nominal



Discussion

Calculating the LCOE for a particular technology in a country with little, or zero, history of deployment is highly theoretical. Where publicly available numbers do exist there are generally very few, which introduces the risk that reported figures reflect value-based pricing rather than the true LCOE. More granular in-country research and an increasing number of real world data points will make underlying costs more visible, and increase accuracy.

Despite deep challenges with data availability and quality, these results are an important first step to better understanding the cost of deploying conventional and renewable energy technologies in least developed countries.

The main conclusion of the study is that in the majority of the priority countries, significant deployment of wind and solar technology is needed for these technologies to become increasingly competitive with coal and gas-fired generation.

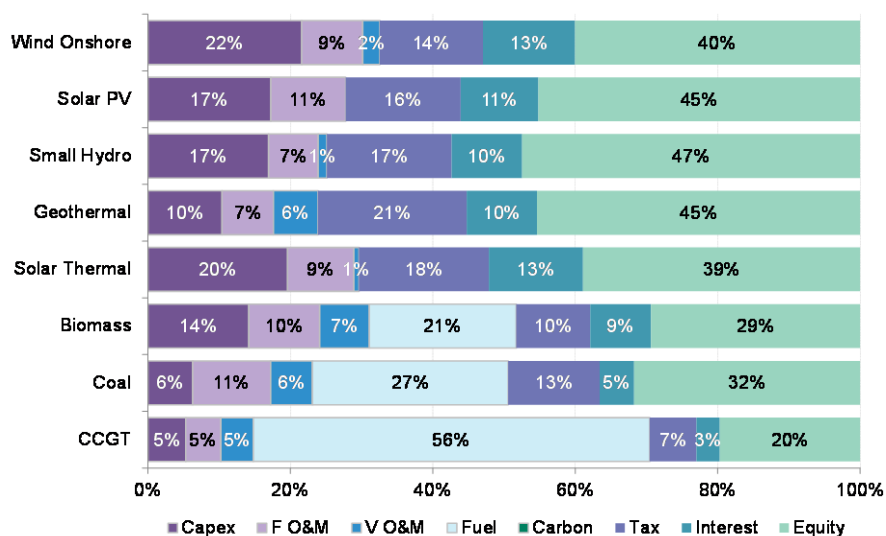
Figure 9 shows nominal costs, by technology, attributed to each major component of the LCOE. The data is taken from averages collected from all of the countries covered in this study.

The costs of commercial debt and equity, which are shown in green, are the most significant cost items for renewable technologies and offer the greatest potential source to reduce the LCOE. Financing costs for renewables are particularly high within the DFID priority countries, due to country risk as well as perceived technology risk resulting from a lack of exposure to these technologies and experience with deployment.

Capex and fixed annual O&M costs are the other significant cost components for renewable energy that could be greatly reduced over time.

Fuel costs stand-out as a major determinant of the LCOE for coal and gas plants, making up around 56% of the lifetime cost for gas, and 27% for coal.

Figure 9: Attribution of component costs to average LCOE, by technology



It is also important to highlight that in practice, the capacity factors for thermal technologies can vary greatly depending on fuel availability. Where fuel supply is uncertain, we have adjusted capacity factors down.

The LCOEs calculated for solar and wind in this study can differ from power purchase agreement (PPA) prices or winning capacity auction bids quoted in the media for a number of reasons. For one, capacity is often awarded at auctions with a 3-5 year grace period for construction. Since wind and solar technology costs are coming down rapidly,^{viii} project developers may choose to bid lower than today's costs. State-sponsored, low-cost finance can also make a material difference to the final LCOE.

There is clearly a growing interest in wind and solar to meet rapidly increasing electricity demand in many of the countries studied as they can be deployed quickly and carry no fuel price, or fuel supply risk. Despite the fall in wind and solar technology costs deployment is critical to build supply chains and reduce balance of plant and operating costs, and put downward pressure on technology and counterparty risks that inflate the cost of commercial finance. Investment from development banks, which require a lower rate of return, would also help lower the overall LCOE.

Competition also is another factor that will help reduce costs. Auction mechanisms have proved effective around the world as developers vie for government tenders.^{ix} Carbon constraints or carbon pricing, will also increase the cost of new coal, gas and oil-fired power generation, in favour of renewables.

This analysis focusses on the cost of grid-connected, utility-scale technologies. However solar PV, biomass and small-hydro can be readily deployed off-grid at small-scale. This is of particular interest in countries with low electrification rates. Small-scale deployment generally has higher dollar per megawatt capex, however it can be cost effective depending on the cost of building-out grid infrastructure. This is a topic of further study.

ⁱ The common assumption used in LCOE analysis is that all technologies pay the same for grid connection, hence it is excluded from this assessment. In practice, however, connection costs can vary. Wind in particular can see higher connection costs when the wind resource in a particular country is far from existing grid infrastructure and demand centres.

ⁱⁱ Bloomberg New Energy Finance, EPVAL methodology, <https://www.bnef.com/core/asset-valuation>, 5 June 2015

ⁱⁱⁱ Bloomberg New Energy Finance, *Q4 2015 PV Market Outlook*, 9 November 2015

^{iv} Resource analysis performed using data from US Energy Information Administration, Vaisala and the International Geothermal Association.

^v Bloomberg New Energy Finance, *Industry Intelligence Database*, accessed 1 August 2015

^{vi} Bloomberg New Energy Finance, *H2 2015 LNG Market Outlook*, 8 September 2015

^{vii} The Bloomberg New Energy Finance Wind Capacity Factor Tool is a C++ model with a MS excel front-end which calculates capacity factors in bulk using 3TIER's premium wind data time-series API and BNEF's manufacturer sourced wind turbine power curve database for any onshore location (latitude/longitude) globally.

^{viii} Solar PV modules have a learning rate of 24% for every doubling of capacity. Similarly, the cost of wind energy has a learning rate of 19%. See Bloomberg New Energy Finance, *The future cost of onshore wind*, <https://www.bnef.com/Insight/13085>, 9 October 2015 and Bloomberg New Energy Finance, *Technology Cost Declines*, <https://www.bnef.com/core/themes/technology-cost-declines>, 23 September 2015

^{ix} Bloomberg New Energy Finance, *Auctions and prices*, <https://www.bnef.com/Insight/13183>, 30 October 2015