ENERGY DARWINISM

The Evolution of the Energy Industry

Citi GPS: Global Perspectives & Solutions

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ENERGY DARWINISM

The Evolution of the Energy Industry

The global energy industry has been transformed in the last five years in ways and to an extent that few would have thought credible. The emergence of shale gas has transformed the U.S. energy market while Germany has seen some gas-fired power stations running for less than 10 days a year due to the impact of solar leading utility owners to issue profit warnings. Developed markets now spend more on renewable capital expenditures than they do on conventional generation, largely due to uncertainty over commodity pricing and likely future utilisation rates, while the legacy of Fukushima has seen Japan burning gas at $16-17/mmbtu while the U.S. basks in $3 shale, driving the introduction of the world's most attractive solar subsidy scheme and catapulting Japan to be the world's second largest solar market. Conversely, the intermittency of renewables has led to the greater demand for the flexibility of gas-fired power plants in some markets.

So, fuel and technology substitution is happening – and not just in developed markets. The shift in emerging markets is less marked, but is nonetheless there. The voracious appetite for power displayed by emerging markets will engender a higher level of new conventional generation (in particular coal), though gas is gradually taking demand from coal and renewables are forecast to represent 10% of new installed power generation capacity in China over the next two years.

Despite these shifts, the analysis of individual fuel and technology cost curves – a key determinant in setting the market price – has continued largely on a standalone basis, with limited emphasis on the risks of substitution. Accordingly, in this report we have combined the work of our alternative energy oil & gas, mining (coal), utility and commodity research teams to create an integrated energy cost curve, which allows us to assess the impact and risks of this substitutional change across all fuel and technology types. Importantly, this integrated curve looks at incremental energy demand and supply, meaning relatively small changes in the mix can have a material impact on the returns of projects, particularly those at the upper end of the cost curve.

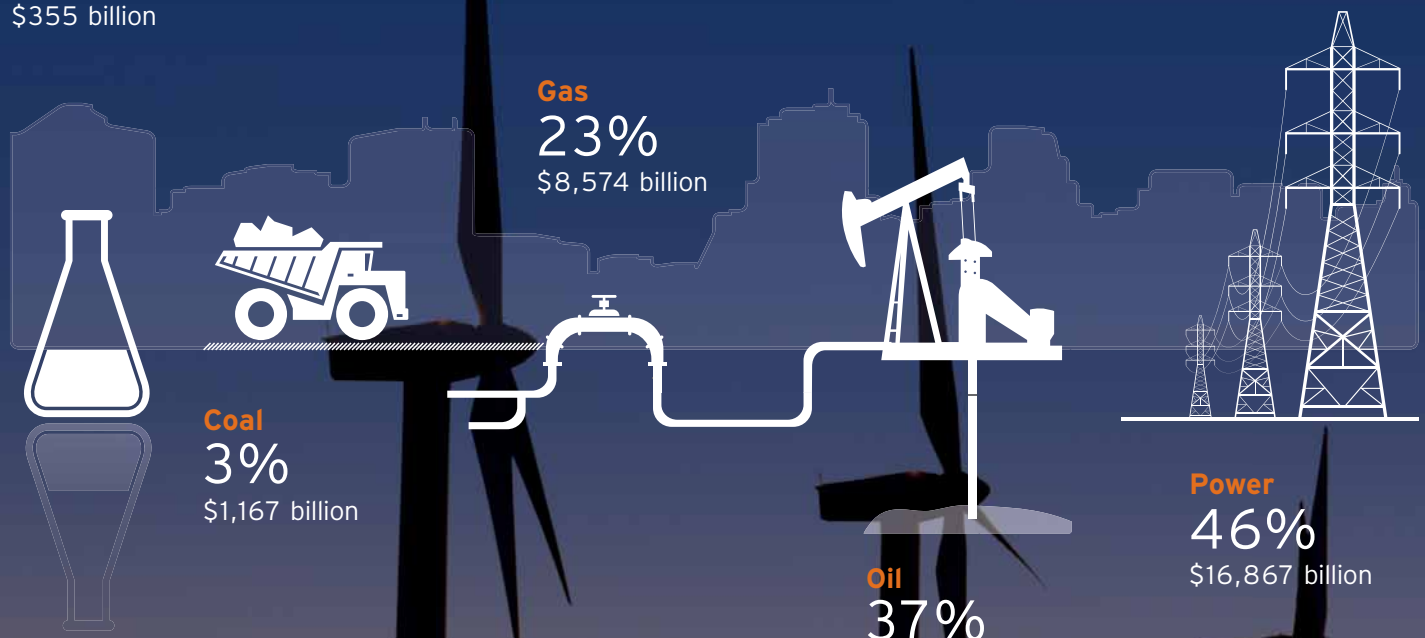
To make the comparison easier, we have focused on the power generation market, as this is by far the largest and fastest growing consumer of primary energy with the highest level of substitution risk. To do this, we have used the levelised cost of electricity (LCOE) concept which allows us to compare different fuels and technologies on a like-for-like basis. We also examine the different evolutionary pace of the various fuels and technology, in an attempt to assess how this curve itself will evolve. Given the long-term nature of both upstream and consumer projects, these changes could well have a material impact within the life of many of these projects.

This analysis of 'Energy Darwinism' highlights the uncertainties and hence risk inherent in upstream projects at the upper end of the gas cost curve, in the coal industry overall, for utilities and for the power generation equipment manufacturers. These changes and risks will affects investors, developers, owners, products and consumers of energy, which given the sums of money involved, makes it of paramount importance to be understood.

Global Energy Supply Infrastructure

Energy substitution in Power Generation changing cost curve

Power (electricity) investment accounts for 46% of the expected
$37 trillion investment in global energy infrastructure to 2035.



Biofuels
1%
$355 billion

Coal
3%
$1,167 billion

Gas
23%
$8,574 billion

Oil
37%
$9,982 billion

Power
46%
$16,867 billion

Source: World Energy Outlook 2012 © OECD/IEA 2012

Power generation is the largest and **fastest growing** component of primary energy consumption.

	2011	2030	Growth
Transport	2.2	2.8	25%
Industry	3.6	4.7	31%
Other	1.3	1.5	19%
Power Generation	5.2	7.7	49%

Billion Tonne of Oil Equivalent

Source: Citi Research, BP Statistical Review

Of the **$9.7 trillion** of global investment in Power Generation, 71% will be in renewables or clean technologies.

	Billions	%
Coal	$1,608	17%
Gas	$1,040	11%
Oil	$74	1%
Nuclear	$942	10%
Bioenergy	$650	7%
Hydro	$1,549	16%
Wind	$2,129	21%
Solar PV	$1,259	13%

Source: Citi Research

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The evolution of the energy industry

While the world of energy is constantly evolving, we believe that the last five years has seen a dramatic acceleration in that rate of change and, more importantly, that the pace of change is set to at least continue if not accelerate further. Simplistically, we believe that certain power generation technologies are evolving -- most notably gas via the shale revolution or solar via technological and manufacturing advances -- while other technologies such as wind are evolving much more slowly, with some such as coal showing more limited evolutionary change. Given the long term nature of investments in these technologies and fuels, we believe that the pace of change will have a profound impact on the returns of both upstream and generation projects. A case study of Germany where the generation landscape has been radically altered in just the last five years shows this is not a 'tomorrow story' — it is happening now, and while it will take longer to impact emerging markets, it will impact an increasing number of industries and countries going forward.

Energy markets have been transformed in the last five years

Who would have thought five years ago that the U.S. would become a net petroleum exporting country, edging out Russia as the world's largest refined petroleum exporter? That the U.S. would be generating more electricity from gas than coal? That German utilities would profit warn with some gas power stations running for less than 10 days a year, because solar has stolen peak demand? Or that utilities would be putting on hold conventional generation projects and building renewable capacity in their stead, even without sizeable subsidies or incentives? The energy market has changed dramatically in recent years and we believe that this mix is only going to alter more rapidly going forwards.

Fuel cost curve analysis remains isolated despite the risk of substitution

Despite this rate of change and the level of fuel substitution, detailed analysis of fuel cost curves has largely remained separated by fuel or technology type rather than undertaken within a holistic energy framework. However, as the experience of the German electricity market shows, fuels and technologies do not exist in their own bubble. There is the risk -- or indeed now the reality -- of technology and fuel substitution, which we expect to become a more prevalent feature in an increasing number of markets as time progresses.

What is a cost curve?

A cost curve is a graph generated by plotting the cost of a commodity produced by an individual asset (e.g. a specific gas field or coal mine) on the vertical axis, against the 'volume' of reserves in that specific asset on the horizontal axes. This is done for all assets (e.g. all gas fields for a gas cost curve) starting with the cheapest first on the horizontal axis, with each volume being added cumulatively. Hence, if we know a likely demand level on the horizontal axis, we can read up to the line and deduce the cost of the marginal producing asset which should be a key determinant in setting the market price.

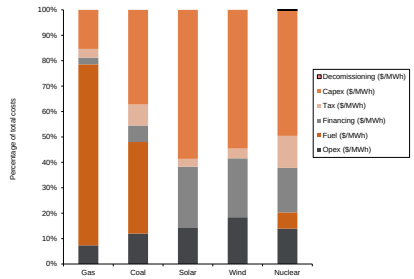
Construction of an integrated energy cost curve…

With this in mind, we have decided to construct an integrated energy curve, combining the work of our alternative energy, oil & gas, metals & mining (coal) and commodities teams. While previous work has highlighted the obvious higher levels of commodity price risk to those reserves or technologies further to the right on their respective cost curves, they did not take the analysis to the next level by examining the interplay between those fuels, and in particular this risk of substitution.

…focusing on the power generation market using LCOE

To do this we have focused on the electricity generation market, using an LCOE approach (see overleaf). While this analysis is not perfect (not least as significant quantities of energy do not go into power generation) power generation is by far the largest consumer of primary energy (50% greater than the next largest) and is by far the fastest growing, Moreover it is perhaps the most transparent and rapidly changing market, as well as the market which offers the greatest potential for substitution, and hence is of most interest in terms of marginal energy supply/demand going forward.

Figure 1. Cost breakdown of LCOE's by fuel



Source: Citi Research

What is LCOE?

LCOE is the 'Levelised Cost of Electricity', which attempts to compare different methods of electricity generation in cost terms on a comparable basis. Different technologies vary materially in the proportion of upfront capital expenditure vs. fuel cost or operating costs, as shown in Figure 1. LCOE incorporates all of these costs and calculates the 'price' of electricity needed to give a certain rate of return.

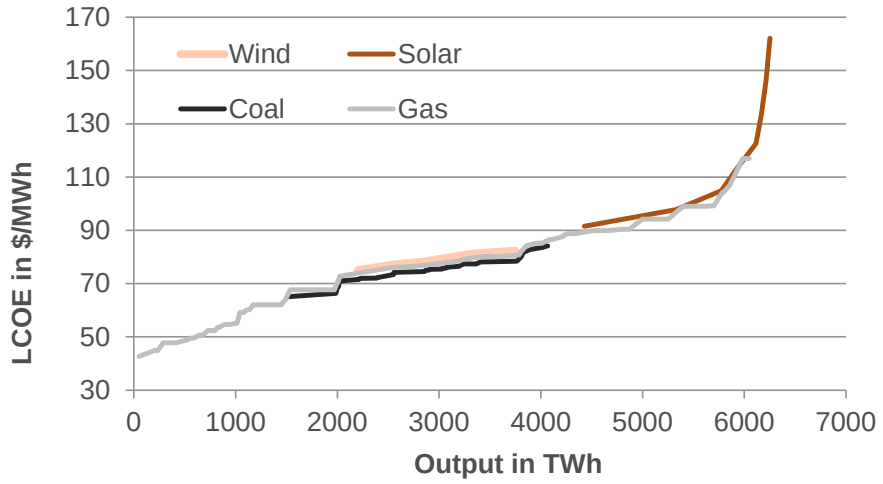
Investments being made now will be subject to relative cost transitions in the energy market which will affect the competitiveness of those fuels or generation technologies, and hence their success or failure. This fuel and technology risk can be witnessed at a customer level by the reluctance of utilities to invest in some large, capitally intensive power generation projects (e.g. nuclear in the UK, US utilities swapping gas peak shaving plants for solar, or German utilities generally) given the medium and long term uncertainty over power prices, utilisation rates and hence returns on investment. As another example of risk, despite the 'shale boom', we would also note that the returns of the US E&P stocks have remained sub-WACC, not something that might have been expected given the excitement surrounding the shale gas boom.

We believe that these transitions are happening faster and to a greater extent than is widely recognised, and hence our efforts to integrate and forecast the various energy curves in an examination of 'Energy Darwinism'.

Citi's integrated energy curve plots incremental energy supply by producing asset out to 2020

The integrated curve shown in Figure 2 shows **incremental** energy supply coming onstream between now and 2020, and consists of the LCOE's derived from the cost of extraction from individual upstream gas and coal projects (the vertical axis), combined with their expected output, which creates a cumulative volume on the horizontal axis.

Figure 2. Integrated energy cost curves for power generation



Source: Citi Research

As Figure 2 shows, gas dominates the first quartile of the integrated cost curve, largely thanks to the advent of shale. However, the gas curve is itself very long, with the lower end of the solar cost curve impacting the upper end of the gas cost curve; moreover, solar steals the most valuable part of electricity generation at the peak of the day when prices are highest. This effect has already caused the German utilities to release profit warnings, with some gas power plants in Germany running for less than 10 days in 2012, all of which makes some utilities reluctant to build new gas plants given fears over long term utilisation rates and hence returns.

Gas dominates the lower end of the cost curve, with solar at the upper end (but falling fast) and wind overlapping with coal

Wind is already overshadowing coal in the second quartile. While wind's intermittency is an issue, with more widespread national adoption it begins to exhibit more baseload characteristics (i.e. it runs more continuously on an aggregated basis). Hence it becomes a viable option, without the risk of low utilisation rates in developed markets, commodity price risk or associated cost of carbon risks.

Evolutionary pace is very different by fuel and technology

Perhaps most importantly is the evolution of each of these industries, fuels and technologies. Solar is exhibiting alarming learning rates of around 30% (that is for every doubling of installed capacity, the price of an average panel reduces by 30%), largely due to its technological nature. Wind is evolving, though at a slower 'mechanical' learning rate of 7.4%, and gas is evolving due to the emergence of fracking and the gradual development and improvement of new extraction technologies. Conversely, coal utilises largely unchanged practices and shows nothing like the same pace of evolution as the other electricity generation fuels or technologies. Nuclear has in fact seen its costs rise in developed markets since the 1970's, largely due to increased safety requirements and smaller build-out.

What is a learning rate?

Learning rates typically refer to the speed of improvement in outcomes of a given task or situation relative to the number of iterations of that task. We use learning rates in the context of this note to describe the speed at which technological or manufacturing improvements reduce the cost of electricity from a particular type of generation (e.g. solar) relative to the cumulative installed base of that generation technology. In this context, a learning rate of 10% would mean that for every doubling of installed capacity, the average cost (or price) of that capacity would decrease by 10%.

Energy substitution is important given the $37 trillion forecast by the IEA to be invested by 2035

Given the long term nature of upstream fossil fuel and power generation projects, this substitutional process and the relative pace of evolution is vitally important to understand. The sums of capital being invested are vast; the International Energy Agency (IEA) forecast that $37 trillion will be invested in primary energy between 2012 and 2035, with $10 trillion of that in power generation alone. Clearly the value at risk from plant or the fuels that supply them becoming uneconomic in certain regions, both in terms of upstream assets and power generation, is enormous.

This analysis of 'Energy Darwinism' as we have chosen to call it highlights the uncertainties and hence the risk inherent in upstream projects at the upper end of the gas cost curve, in the coal industry overall, for utilities, and for the power generation equipment manufacturers. These changes and risks will affect any investor, developer, owner, producer or consumer of energy which, given the sums of money involved, makes it of paramount importance to understand.

Breaking down the global energy complex

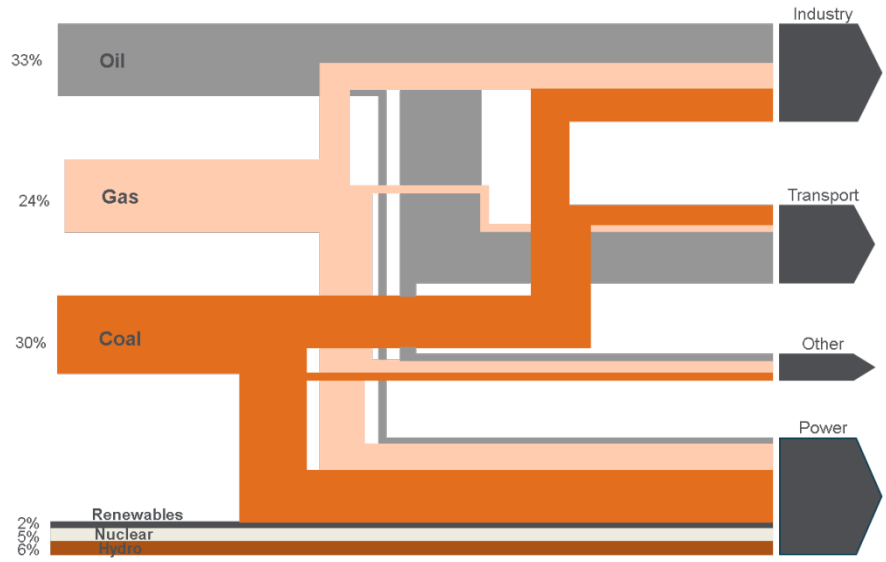
Different geographies are undergoing different changes in their energy mix; contrast the voracious appetite for power in emerging markets largely being met by conventional generation, with the reducing demand in developed markets where existing generation is being cannibalised by renewables. In this chapter, we highlight the different challenges facing different parts of the world, and how the interplay between the different generation technologies fits into these challenges. Will peaking gas win at the expense of coal and nuclear baseload, or vice versa, and in which geographies around the world? Or will renewables change the playing field for everyone? While we choose to focus on the power generation market as the largest consumer of primary energy (and the fastest growing), these changes will affect the returns — both positively and negatively — not just of utilities, but also of upstream fossil E&P companies in terms of demand, pricing and returns on investment, as well as for equipment manufacturers in terms of demand for power generation equipment.

Forecasting the future of energy markets is complicated by the enormous range of variables and feedback loops

Trying to predict the future of the global energy mix is always a complex process given the number of different fuels, changing technologies, new discoveries, economic influences on demand and geopolitical factors, combined with the multiple stage feedback loops of pricing, supply and demand which are now exacerbated by a greater ability to transport energy.

Moreover, there is not one single end-use; energy is used in a variety of ways, most notably in transportation, industry, and power generation, as highlighted in Figure 3 which shows the split of global primary energy supply and demand by source and end use in 2011.

Figure 3. The split of primary energy supply by source and end user group



Source: Citi Research, BP Statistical Review of World Energy

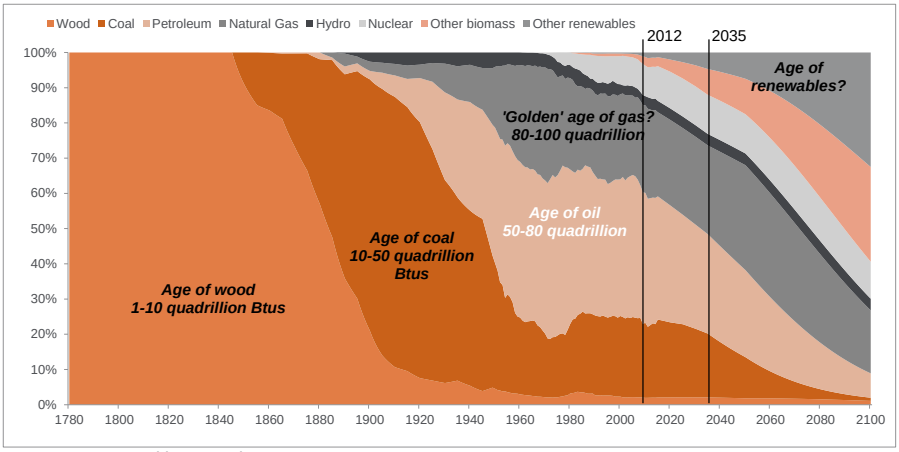
The industry is constantly evolving

However, Figure 3 offers a snapshot at a particular time, whereas the energy mix has constantly evolved through history. Both the upstream projects to source those fuels and the end user facilities tend to be long term in nature (and relatively inflexible), hence making the right choice of energy source is of paramount important to both producers and consumers alike.

Lessons from history

History tells us that typically in the world of energy we don't tend to move gradually to a more balanced energy mix as new fuels or technologies come along, rather we tend to (over)embrace those new technologies at the expense of incumbent technologies or fuels. Figure 4 shows the evolution of the U.S. primary energy mix from 1780 to the present and projected out to 2100. While we are currently in the midst of a more balanced energy mix, we believe it would be naive to ignore the waterfall progression that history suggests is likely; as conventional fuels become gradually more scarce and expensive (assuming the lowest hanging fruit has been harvested first) and as new technologies improve, the long term transformation becomes ever more inevitable. Moreover, this ignores the potential for the advent of new technologies equally as unforeseeable now as solar would have seemed a few decades ago.

Figure 4. The ages of energy: History suggests a process of substitution



Source: IEA, EIA, Citi Research

Substitutional changes are happening to a degree not widely recognised

However, as Figure 4 suggests, the 'balanced transition' part is likely to continue for some time – certainly beyond the boundaries of any normal investment timeframe. So isn't this analysis of substitution just an academic exercise? We believe that the answer is an emphatic no. This substitution effect is already happening to a degree which we believe is not widely recognised, and moreover sizeable investment decisions being taken now by E&P companies, oil majors, utilities and renewables developers will be affected by the changing shift within the lifecycle of those projects, and in some cases in the early years of those projects.

Germany provides a cautionary tale for developed markets

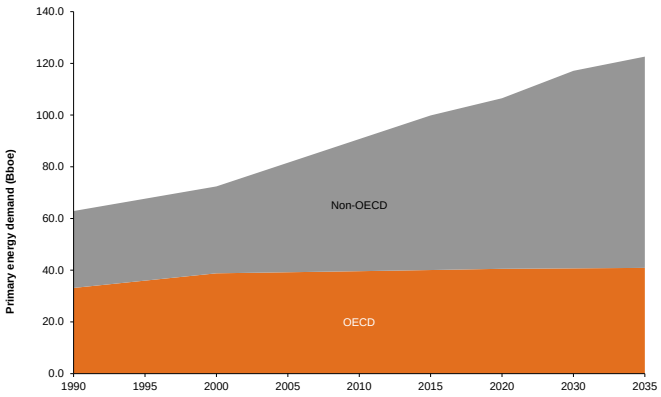
Germany provides a cautionary tale for the world in terms of how quickly the energy mix can change beyond all recognition, and how profound and wide-reaching the implications of that transition can be; this case study is examined in detail within this report.

Developed vs. Emerging markets

Dynamics are different for developed and emerging markets

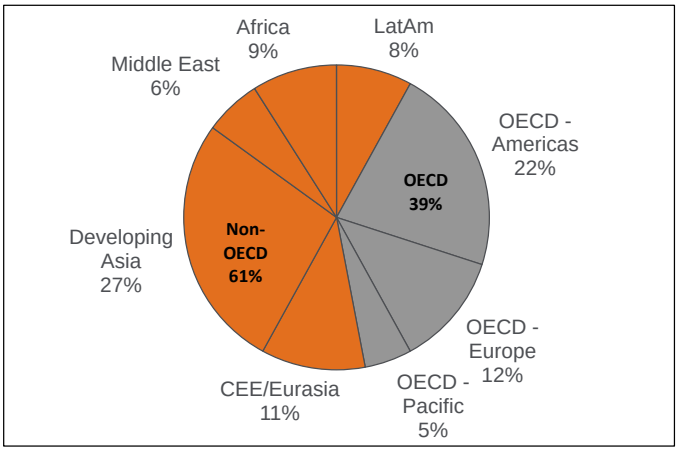
While a fast transition in energy markets might be possible for a highly developed market like Germany, does it provide an applicable template for the world, or only developed markets? Certainly it is worth looking at developed and emerging markets separately as the dynamics are indeed quite different. As Figures 5 and 6 show, the vast bulk of energy demand growth over the coming two decades will come from emerging markets, with around 60% of the investment in primary energy also coming from those nations.

Figure 5. Global primary energy demand 1990-2035, bboe



Source: IEA, BP Statistical Review of World Energy, Citi Research

Figure 6. 61% of the $37trn required investment in energy to 2035 will be from non-OECD countries

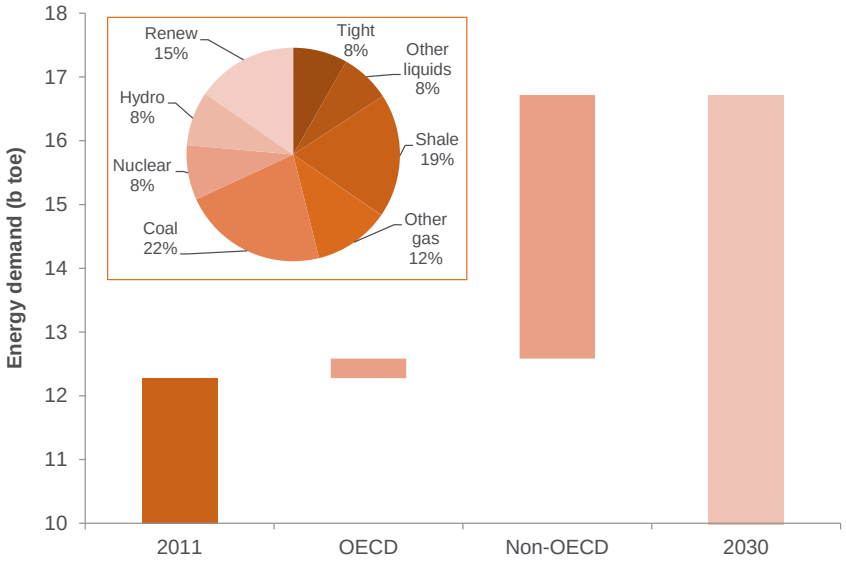


Source: World Energy Outlook 2012 © OECD/ IEA 2012

Emerging markets offer bulk of energy growth, but split of investment is broadly spread

What is essentially happening is a process of substitution of energy sources in developed markets, and new capacity build in emerging markets. Figure 7 examines the dramatic growth in primary energy demand forecast for the next two decades, split by OECD and non-OECD demand, as well as showing the forecast for how that demand is expected to be met.

Figure 7. Energy demand growth will be dominated by non-OECD countries, but the split of fuels/ technology will be relatively even split



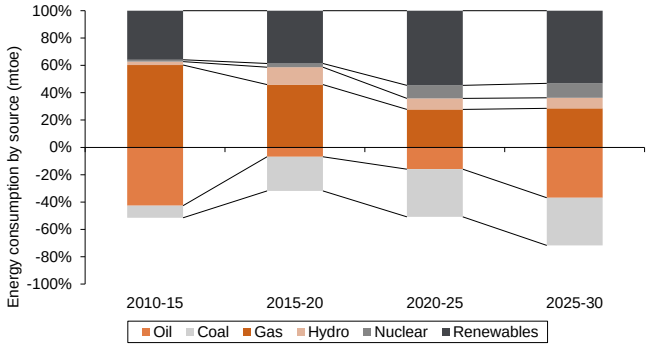
Source: Citi Research; BP Statistical Review of World Energy

Perhaps surprisingly, the split of technologies and fuels providing that energy is a broadly mixed one. However, as discussed, the picture is quite different for developed and emerging markets.

Developed markets experiencing substitution while emerging markets focus initially on conventional generation...

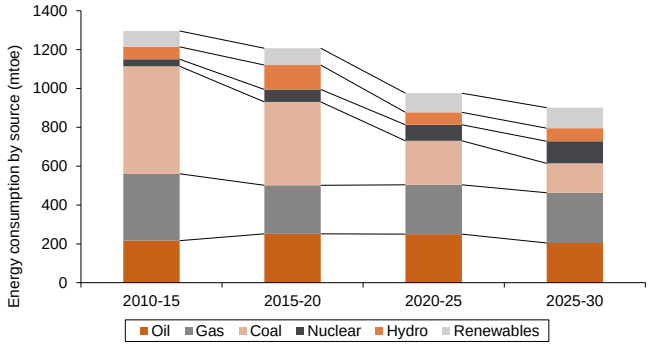
Figure 8 shows that, in developed markets, while net energy consumption will increase, this will consist of a reduction in usage of oil and coal, more than offset by increases in energy consumption from mainly gas and renewables. Conversely, while emerging market demands are much higher (Figure 9), the bulk of this demand in early years will be met by conventional energy sources such as oil, coal and gas.

Figure 8. Developed market incremental energy consumption by source 2010-30 mtoe



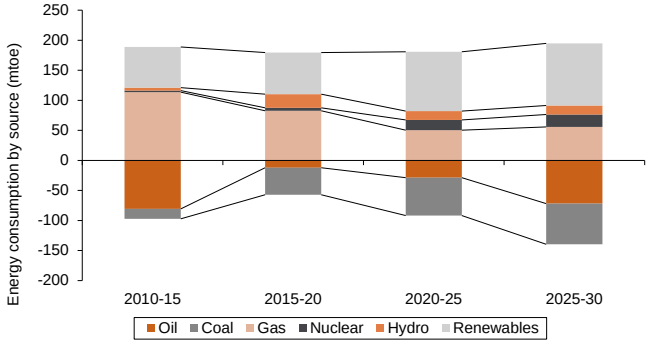
Source: Citi Research; BP Statistical Review of World Energy, IEA

Figure 9. Emerging market incremental energy consumption by source 2010-30 mtoe



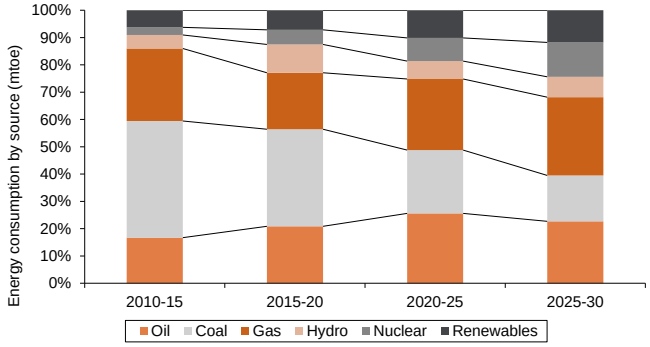
Source: Citi Research; BP Statistical Review of World Energy, IEA

Figure 10. Developed market proportion of incremental energy consumption by source



Source: Citi Research; BP Statistical Review of World Energy, IEA

Figure 11. Emerging market proportion of incremental energy consumption by source



Source: Citi Research; BP Statistical Review of World Energy, IEA

…though nuclear, hydro and renewables take increasing share of new build in later years in emerging markets

Figure 10 once again shows the increasing importance of renewable technologies in developed markets. It is worth noting that, in later years, renewables represents more than half of new energy consumption; indeed if one looks purely at the electricity generation market in developed markets, investment in renewables is now larger than that in conventional generation.

As Figure 11 shows, while oil increases its share in emerging markets (driven by transport) as does gas, coal reduces significantly while renewables and nuclear increase materially.

So, while new technologies are more important for developed markets, they are still increasing in emerging markets and are far from marginal.

Renewables are being more widely adopted due to dramatic reductions in cost that have made them competitive

So why are renewable technologies being adopted far more quickly than was previously expected? The simple answer is that costs have reduced far faster than anyone expected, for a variety of reasons. The fastest reductions in cost have been seen in the solar sector where the price of an average panel has fallen by 75% in just four years. Given that there are no 'fuel costs' to solar, and that the investment

is all up-front capital expenditures (capex), the impact of this on the competitiveness of solar vs. conventional generation is clear. Indeed solar is already at or approaching 'socket parity' in many markets, and is being built on a larger scale by some utilities (even in the shale-endowed U.S.) instead of gas peaking plants. These cost reductions in solar have been so quick largely because of the technological nature of panels. In our view they have far more in common with a semiconductor wafer (indeed they are basically the same thing) and the technology sector than they do with mechanical electricity generation equipment. It is this technological nature which has allowed lab-based R&D activities to improve output (e.g. doping and coatings), and reduce material usage (e.g. thinner wafers). On top of this, physical changes such as moving manufacturing to lower cost areas in Asia, as well as economies of scale, have also reduced costs. While the cost reductions in wind turbines have been slower (given its more mechanical and multi-component nature), they are nonetheless impressive and are helping to make what was already a competitive technology even more so.

Added to these cost benefits is the lack of pollution which is also becoming a key driver in markets such as China, where the preponderance of coal-fired generation is having a noticeable impact on air quality.

The emergence of renewables as a competitive force has not been without its teething troubles. Most notable is the solar manufacturing space which is littered with bankruptcies and insolvencies from the U.S., to Germany and China. This was largely due to the classic 'boom and bust' cycle which the nascent industry went through in 2006-2012 (much as the technology/internet sector did in 2000) where supernormal returns on capital (in some cases of nearly 50%) were being enjoyed by early mover manufacturers as an undersupplied industry struggled to meet exploding demand driven by the introduction of attractive incentive mechanisms for solar such as Germany's feed-in tariff. Inevitably these returns led to cyclical overinvestment and significant overcapacity, which itself then led to dramatically falling prices due to higher levels of competition.

Focus on incremental demand

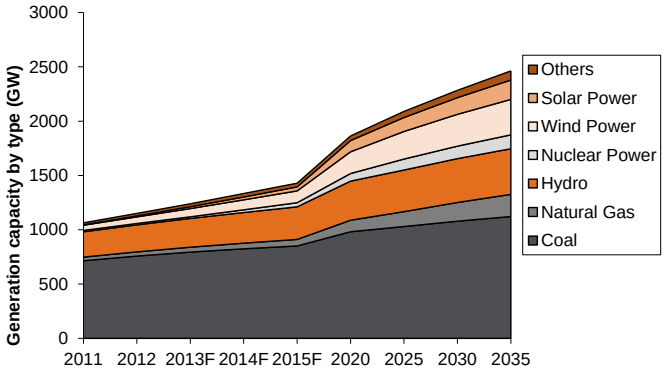
The integrated cost curve analyses incremental energy supply and demand, and hence even small swings are important

It is important to remember the focus of this report – we are examining **incremental** energy sources 'coming onstream' between now and 2020, and while new technologies are expected to be smaller overall than conventional, the important point is that they represent a potential alternative choice to conventional energy sources. Given the nature of analysis of energy cost curves and the importance of the marginal supplier, even relatively small adoption of different fuels or technologies has material implications for energy assets higher up the integrated cost curve. For example the 7% of incremental energy demand which renewables represents even in emerging markets from 2015-20, and 10% from 2020-25 still represents material amounts of conventional energy which will not therefore be used. In developed markets while energy demand growth is subdued, the substitution of new for conventional technologies will also displace that fuel which would otherwise have been burnt onto markets, with implications for price and hence returns on upstream projects.

Wind and solar will represent 20% of new power generation capacity in China from 2020 onwards

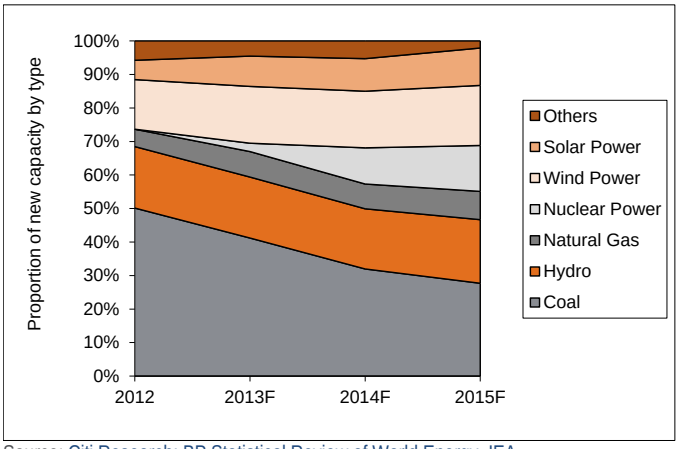
If we look at this issue in more detail for China, the most important growth market in terms of electricity generation capacity, the same picture is borne out. While demand for all energy sources is growing, (Figure 12), the decreasing importance of coal is notable, as is the increasing proportion of solar and wind power. Indeed from 2020 onwards, wind and solar represent around 20% of incremental power generation capacity in China, not a negligible amount, again with implications for conventional generation sources (in this case coal) which are therefore displaced.

Figure 12. New power generation capacity in China by type



Source: Citi Research; BP Statistical Review of World Energy, IEA

Figure 13. Proportion of new power generation capacity in China

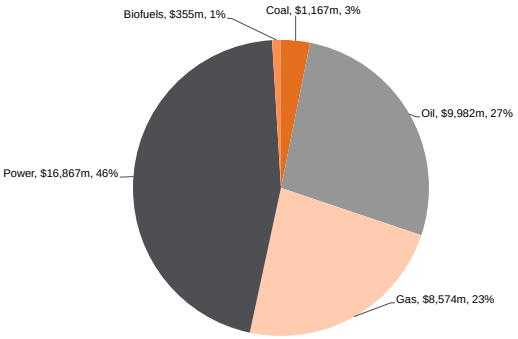


Source: Citi Research; BP Statistical Review of World Energy, IEA

Investment by energy source

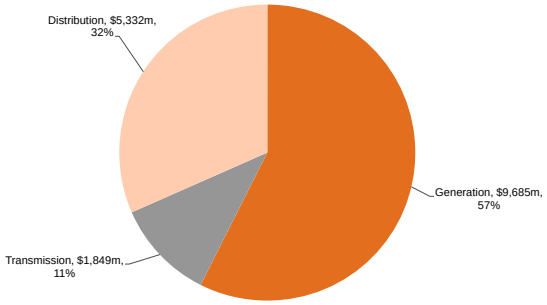
This investment of $37 trillion in primary energy forecast by the IEA out to 2035 can be broken down into requirements by energy use, and by fuel type.

Figure 14. $37trn of investment in global energy supply infrastructure, 2012-35



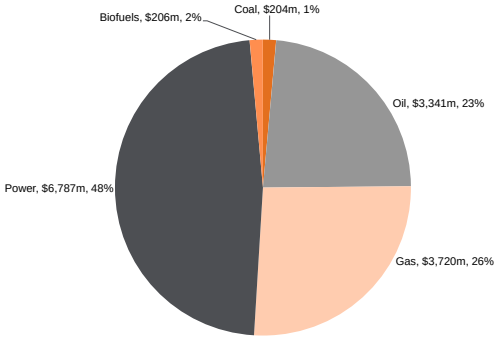
Source: World Energy Outlook 2012 © OECD/ IEA 2012

Figure 15. Split of $16.9trn investment in global power generation by activity, 2012-35



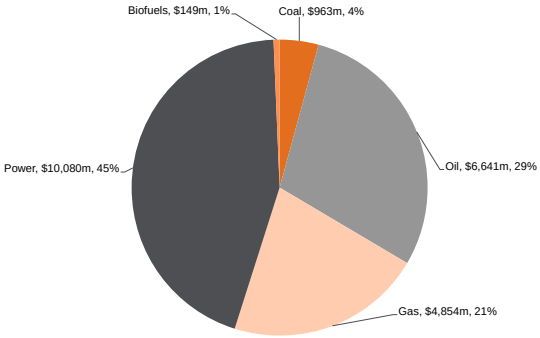
Source: World Energy Outlook 2012 © OECD/ IEA 2012

Figure 16. Split of investment in energy supply infrastructure, OECD, 2012-35



Source: World Energy Outlook 2012© OECD/ IEA 2012

Figure 17. Split of investment in energy supply infrastructure, non-OECD, 2012-2035



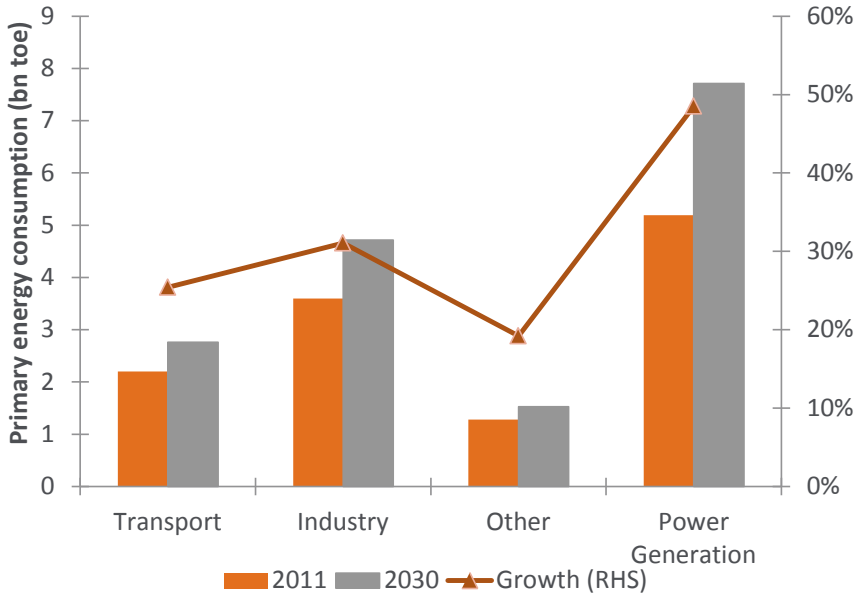
Source: World Energy Outlook 2012© OECD/ IEA 2012

Figure 14 shows that, of this $37 trillion, by far the largest part will be the $16.9 trillion invested in the power industry (i.e. electricity), with $9.7 trillion of this figure being in power generation (Figure 15), the remainder being accounted for by transmission and distribution. As before, the greater part of this investment in power generation will be accounted for by non-OECD countries (Figure 16 and Figure 17).

This report focuses on the power generation market

For the purposes of this report, which is looking at the evolution of fuels and energy technologies, we have chosen to analyse the electricity power generation market for the following reasons, ably demonstrated by Figure 18.

Figure 18. Primary energy consumption by end use, 2030 vs. 2011, showing growth



Source: Citi Research; BP Statistical Review of World Energy

- Not only does power generation represent the largest part of primary energy consumption being almost 50% larger than the next end use, but it is also the fastest growing end consumption group, growing 49% by 2030, vs. transport and industry at 25% and 31% respectively.
- Power generation represents arguably the market with the most easily transitionable energy mix, whereas the economic choices to move away from oil in transport (in any scale) are as yet more limited.
- Utility purchasers are likely to be amongst the most sophisticated customers and hence developments here are potentially the most price sensitive making direct comparison easier.
- Given that solar photovoltaic (PV), wind and nuclear are only directly applicable to the power generation market this makes direct comparisons easier.

Power generation is the largest and fastest growing end market for energy

Hence for the purposes of this note while we do examine energy substitution in transportation, we have chosen to focus on the cost curves relating to the power generation mix, via the concept of Levelised Cost of Electricity (LCOE).

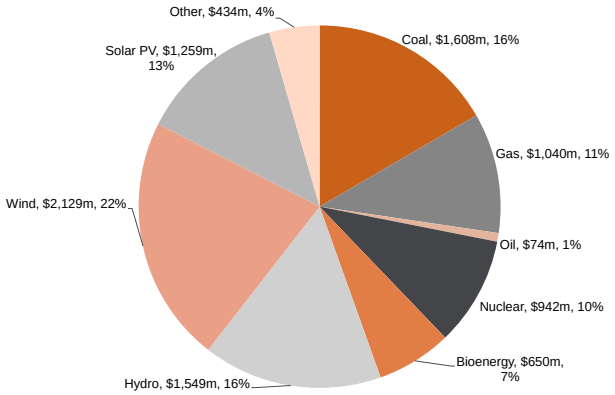
Moreover, it is worth stressing once again that the integrated cost curve analysis that is the crux of this note relates to **incremental** energy supply coming on between now and 2020, and hence although some technologies may be relatively small now, it is their applicability as a 'choice' which affects the relative economics of new conventional projects at the upper end of their respective cost curves.

Investment by power generation technology

If we look at the forecast split of investment in the electricity generation market, the impact of a broader energy mix on conventional technologies becomes more apparent.

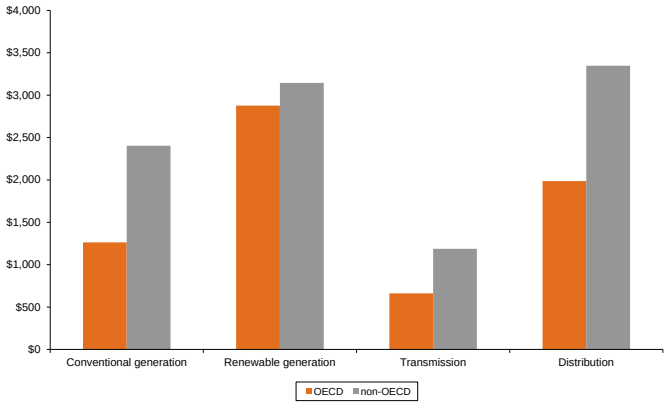
Figure 19 examines the split of the $9.7 trillion global investment in power generation by technology highlighted earlier.

Figure 19. Split of $9.7trn global investment in power generation by technology



Source: World Energy Outlook 2012© OECD/ IEA 2012

Figure 20. Split of investment in generation, transmission and distribution by OECD and non-OECD



Source: World Energy Outlook 2012© OECD/ IEA 2012

Figure 19 shows that only 29% of that $9.7 trillion of investment will be in 'fossil fuel' generation technologies (coal, gas & oil), with the remainder being in renewable or clean technologies.

Investment in new power generation technologies is expected to be larger than in conventional generation…

Figure 20 highlights once again that while conventional generation is far more important in developing markets than in it is in mature markets, the investment in renewables in non-OECD regions is still expected to be larger than in conventional over that time period (and larger than that invested in renewables in developed markets). Admittedly the picture is different in terms of capacity, as renewable capacity is more expensive in terms of upfront capex, but we should remember that renewables thereafter has almost zero operating cost, while conventional generation has the ongoing impact of fuel costs.

…even in emerging markets

Accordingly, we believe that energy market transformation is not just a developed markets issue; it is happening across the globe, albeit at different rates, and its impact on marginal energy supplies is of paramount importance.

The hidden costs of the energy transformation

There are extra costs associated with this transformation…

Figure 19 previously highlighted how important renewable generation is as a proportion of the total $16.9 trillion investment in the electricity sector, especially given that transmission investment is higher for renewables per MW of capacity than conventional, due to three key factors:

1. Utility-scale renewable generation is normally located at a greater distance from population (and hence usage) centres

2. Utility scale renewable generation facilities tend to be smaller than conventional generation sources, and hence the grid connection infrastructure is greater per MW of capacity than for conventional.

3. The intermittent nature of renewable generation leads to greater grid stability and balancing costs, in part due to technology costs

The IEA estimates that the total integration costs of increasing the supply of intermittent renewable energy sources to be ~$5-25/MWh, broken down as follows:

1. ~$3-5/MWh in extra capacity costs, to ensure peak demand can be met during period of intermittency;

2. ~$1-7/MWh in extra balancing costs to maintain grid stability; and

3. ~2-13/MWh in extra grid integration costs (i.e. transmission and distribution) since renewables are often located far from demand centres.

These factors combined with current economics and less developed grids and power data management capabilities are the key drivers behind the focus on planning authorities in emerging markets on conventional generation technologies.

…but we do not believe that they will be a material impediment to the evolution of energy markets

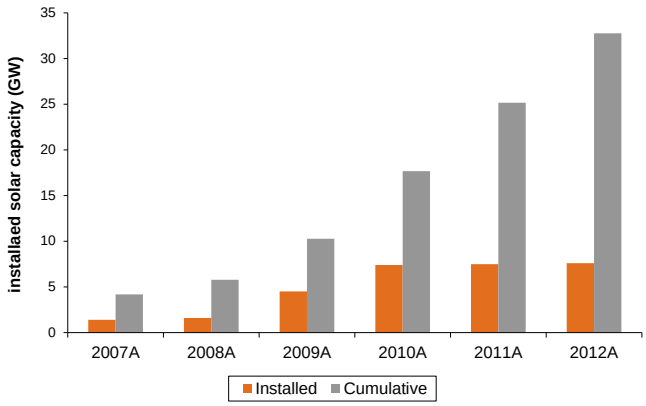
However, while these might be viewed as an impediment to installing new technologies, we would observe that in a majority of cases these costs are not borne by the developer of the renewable asset, but either centrally or indirectly by customers by means of a 'renewables surcharge' and hence are not necessarily a deterrent to developers who focus more on the economics of the project. So, while these issues are of importance to authorities and central planners, they may be less of an issue to those that are building the plant. Moreover, these new technologies do form an important plant of centrally planned energy policies in developing markets, largely as part of a desire for a broader energy mix and a greater level of energy independence.

We have not explicitly added these costs onto renewable technologies on the cost curve, largely for the reasons above; they are in most cases not a cost which is borne by the developer of the power project, i.e. the person making the decision about which type of generation facility to build, or which power to use. Moreover, there are other costs also not included on the curve which vary from market to market, the most obvious being the impact of a cost of carbon on coal. However, these variations should of course be considered when analyzing the output of the cost curves.

Developed markets: Germany, a case study

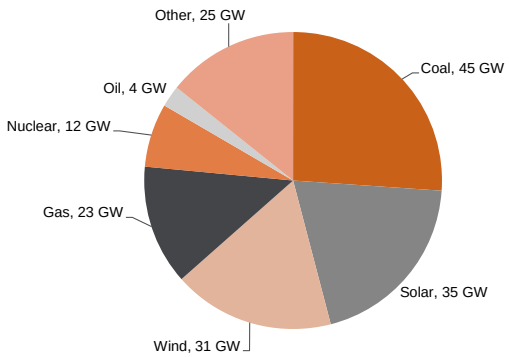
In just 6 years, there has been a fundamental shift in the Germany electricity generation mix, as highlighted in Figure 21 and Figure 22.

Figure 21. German solar installations, 2007-2012



Source: Bundesnetzagentur

Figure 22. German generation capacity mix, July 2013



Source: Bundesnetzagentur

German power market has changed beyond all recognition in just 5 years

As Figure 21 shows, in 2007 annual solar installations were relatively limited at just 1.4GW, but this grew to 7.4GW per annum in just 3 years, and stayed at that level for the next 3 years (although they are expected to slow in 2013). To put this capacity in context, a typical gas fired power station might be 0.5GW, and a large nuclear station 1GW; hence Germany has been installing seven and half nuclear power stations-worth of solar peak generation per year for the last 3 years. As Figure 22 shows, solar now represents 50% more capacity than gas, and is not far behind coal in terms of peak capacity. To be fair solar generates for only a fraction of the time, hence the total units of power generated are much smaller than for nuclear, coal or gas, but the peak capacity is key for a variety of reasons, as we examine.

The theft of peak demand

There is, in our view, limited awareness of the extent of solar's interference with conventional generation

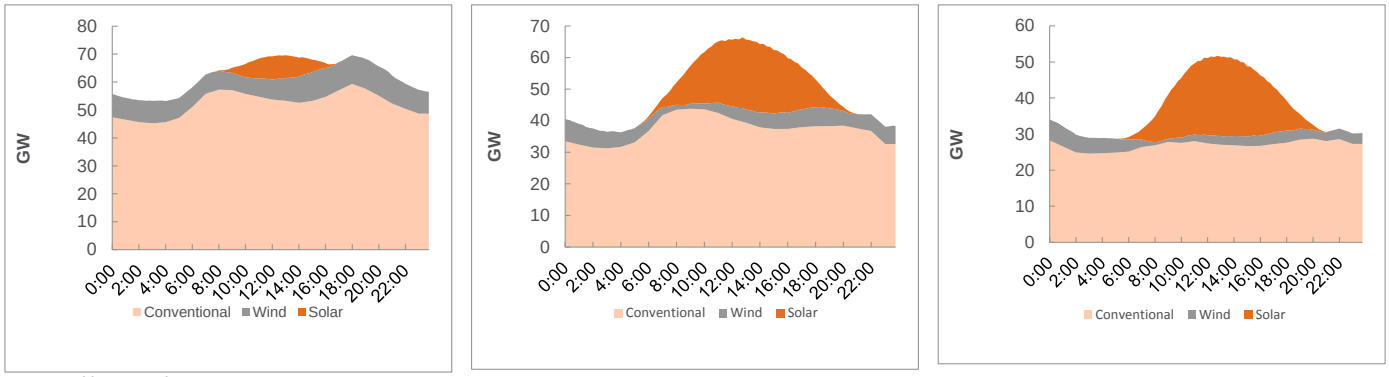
While solar generates only a relatively small amount of units of energy per unit of capacity (a low 'load factor' or utilisation rate of about 10-15%), it is the time of day at which it generates those units which causes the biggest headache for utilities.

What is a demand curve?

An electricity demand curve — or technically speaking a 'load curve' — shows how the demand for electricity varies over time. Load profiles, or the shape of the curve, vary between countries, with hotter countries tending to show a peak demand in the middle of the day driven by industrial/ business activity combined with air conditioning. Colder countries tend to have flatter load profiles across the day, due to the lack of air conditioning demand combined with heating demand in the morning and evenings.

Figure 23 shows actual German electricity demand curves from various days in 2012, showing which type of generation supplied that demand in terms of conventional generation (i.e. nuclear, gas, coal etc.) vs. solar and wind. The perhaps surprising conclusion is that on hot sunny workdays and weekends, the peak level of demand in the middle of the day (which would previously have been supplied by gas) is now entirely provided by solar. What is even more impactful about this is that this is the most 'valuable' part of the curve to supply, as electricity prices are highest at periods of maximum demand. For other countries, the hotter/sunnier the climate, the bigger the mid-day peak is likely to be, due to air conditioning, those sunnier characteristics of course only serving to make solar perform better. Hence while the amount of units supplied by solar are currently relatively small, their share of the 'value' of electricity supplied across the day is considerably higher.

Figure 23. Solar has stolen the peak of the electricity demand curve when prices are highest, displacing gas fired capacity. German electricity market, (left to right) winter workday (1/2/12), sunny workday (25/4/12), and sunny weekend (26/5/12)



Source: Citi Research, EEX

The 'loss' of the peak has already caused some utilities to issue profit warnings

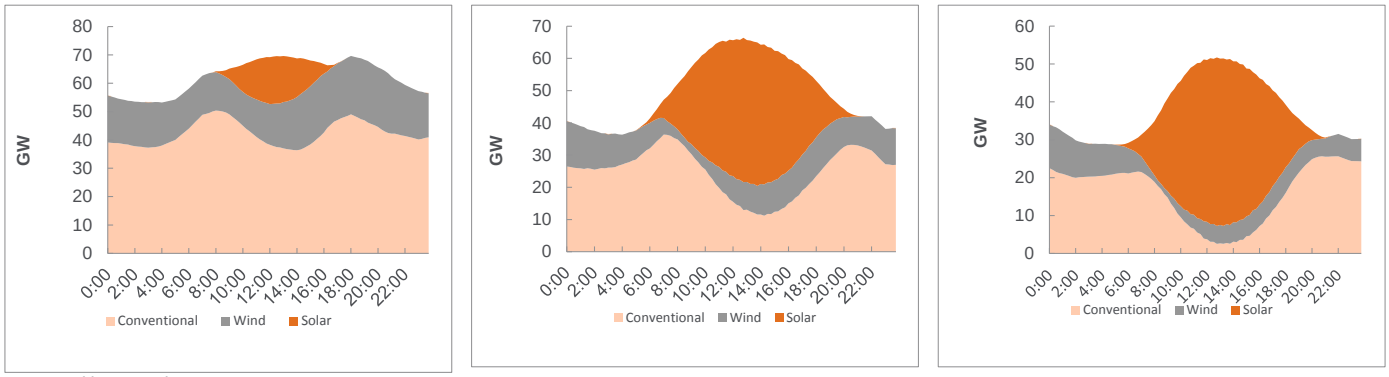
This effect of solar providing all of summer peak demand has resulted in some gas power plants in Germany running in 2012 for less than 10 days, with resulting profit warnings from their utility owners who as recently as two years ago saw renewables as 'niche' technologies.

What are baseload and peaking plants?

Electricity demand fluctuates through the day and the seasons and varies between countries. Baseload is power generation which effectively runs constantly, while peaking plant is flexible generation capacity which is turned on and off throughout the day to meet those fluctuations in demand. The economics of generation dictate that baseload is normally supplied by coal and nuclear (and increasingly wind) while peak demand is met by gas (and increasingly solar).

Coal and nuclear generation have very low marginal costs of generation (i.e. the fuel cost is limited, with fixed costs being a much greater proportion of costs), which combined with the fact that they take time to turn on and off, means that they tend to run almost continuously (nuclear 90%+ of the time, coal ~80%). For gas however, fixed costs are lower, with fuel costs being much more significant (see Figure 79) and hence gas only tends to run (about 20-60% of the time) when prices are higher at times of peak demand. Accordingly, gas has been the first to suffer the effects of solar supplying all of peak demand. Where the situation becomes really worrying for conventional generators (and indeed the consumer) is if we project these penetration levels forward, as in Figure 24.

Figure 24. The same German load curves with (simulated) double the penetration of wind and solar, showing the disruption to baseload, (left to right) winter workday (1/2/12), sunny workday (25/4/12), and sunny weekend (26/5/12



Source: Citi Research

This disruption of baseload is likely to cause energy markets to move to a capacity payment mechanism

Figure 24 shows the impact on the German generation mix assuming double the 2012 penetration of wind and solar. This equates to 53GW of solar generation capacity, (as of mid-2013 we are already at 35GW) – at 2012 annual installation rates we would hit that level within 3 years. Whereas in the previous example solar 'stole' peak demand from gas, in this scenario we can see renewables eating into baseload. Indeed in the right-hand chart of Figure 24 (the sunny weekend), it is notable that baseload has all but ceased to exist (i.e. the bottom, grey band goes to zero in the middle of the day). If solar installations continued further we would actually end up with excess solar generation. We believe that this eating into baseload will actually drive demand for more gas-fired plants given its flexibility, to operate on the 'shoulders' of the chart (i.e. morning and evening) when renewables are not generating. Given the economics of baseload generation (i.e. it must run all the time), this solar penetration would have a material impact on the utilities operating this baseload plant, given that lower load factors (i.e. not running all the time) would lead to this plant being uneconomic.

Ultimately, we believe that markets such as Germany must move to a 'capacity payment' mechanism, whereby the owners of conventional plants are compensated (via consumer bills) simply for keeping this plant open and available (but not actually running), so that it is available when it is needed i.e. in the winter, the left hand charts of Figure 23 and Figure 24. This capacity payment model would essentially delink the results of these companies/assets from their operational characteristics. Ultimately, this could see these conventional utilities reverting to rate of return, regulated asset-based companies, an ironically circular evolution back to the days of state-owned utilities prior to European market liberalisation.

Distributed nature of solar means lower utilisation for networks

Furthermore, the fact that much of this generation is distributed generation (e.g. rooftop solar located at the point of use vs. large scale centralised generation) has huge implications for the electricity grid. Fewer units will travel over infrastructure that is traditionally remunerated on a per unit basis. Moreover, even though that grid might be used less in the summer (when distributed, solar generation is supplying much of electricity) it has to be maintained for use by centralised generation in the winter when solar is not running, thereby requiring higher per unit charges (costs of maintenance are the same, number of units is less across the year). Ironically this combined upward impact on electricity bills (of capacity payments for stranded generation and higher grid per-unit charges) is in our view only likely to make consumers *more* likely to put panels on their roofs in a desire for a greater degree of energy independence.

Figure 25. Load factor of traditional technologies has been steadily declining in Europe

Source: ENTSO-E, NORDEL, Eurostat, NG SYS, Bloomberg, Citi Research

Figure 25 shows the impact of renewables (amongst other effects) stealing electricity demand from conventional electricity generation, with load factors on conventional generation plant across Europe as a whole falling significantly in recent years. While this is for Europe as a whole, those countries more affected by renewables such as Germany will have seen a much more marked swing in utilisation, and it will also differ materially by fuel/technology.

Solar has already led to negative power prices in Germany at times

One possible solution is that baseload keeps running at optimum load factors (i.e. all the time), but that the power generated surplus to demand is exported. This situation has already arisen in Germany in 2012 with negative electricity prices on some occasions, i.e. giving free power to industrial consumers along with cash simply to balance the grid (with obvious economic connotations). This has even resulted in power being 'dumped' across national borders, which then starts to impact other markets, a situation which has been evident in Denmark for some years now given its very high percentage of wind generation (~30%). Clearly as more markets take on a greater proportion of renewables, the ability to 'dump' power across borders becomes less (as they will have their own renewables), and hence grid stability becomes a greater issue. Grid stability suffers because on an electrical system, supply and demand must be balanced at all times, otherwise 'brown-outs' or full 'black-outs' occur.

Storage may be the key for developed markets, but is commercially some way off

Electricity storage is potentially the answer, but this only serves to make solar more competitive as it removes the main hindrance of renewables — their intermittency. It is this need to balance supply and demand on grids that we now believe will drive investment in storage — essentially stopping the lights going out due to an imbalance in supply/demand. We believe that this will be a much more powerful driver of investment in storage than the historical expectation that storage would be developed to make renewables cost competitive (which in many situations they now are anyway).

Utilities may ultimately evolve into more localised entities, with centralised back-up generation

Given its modular nature, solar works well as a distributed (local) generation source, which when combined with local storage (potentially in the much longer term from electric vehicles), could ultimately see the utility industry split into centralised back-up rate-of-return generation (much as it was throughout the world pre-privatisation), with much smaller 'localised' utilities with distributed generation and storage managing local supply and demand, potentially even on a 'multi-street' basis. Whether those companies are traditional utilities, metering/technology companies, or branded 'customer service' companies is also open to question. Indeed in Germany, the town of Feldheim has constructed its own local grid to achieve energy independence given its extensive local renewable generation.

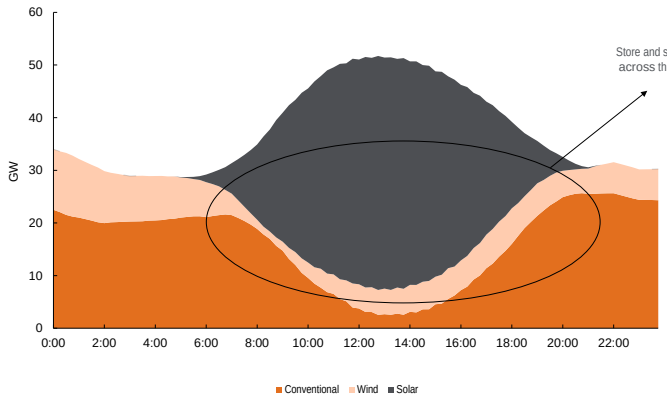
Germany has introduced a pilot storage subsidy scheme, much as it did with solar

Much of this 'local utility' and storage speculation is ultra-long-term crystal ball gazing, but the point is that the utility market could look dramatically different in the not too distant future. In May 2013 in a tacit admission of the problems being caused by solar, KfW (the German state bank) started a pilot energy storage subsidy programme, similar to that which launched the solar boom 10 years ago, the adoption of which has been extremely fast.

Storage may be the next solar boom in Germany

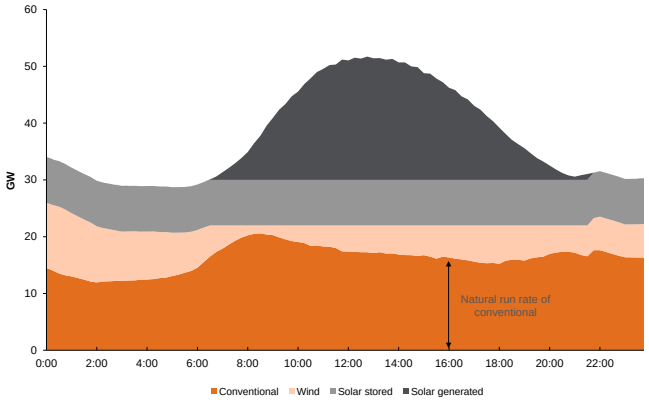
If, as we suspect, storage is the next solar boom and becomes broadly adopted in markets such as Germany, the electricity load curves could once again change dramatically causing more uncertainty for utilities and more disruption to fuel markets. With baseload still operating flat out, the surplus solar generation which would otherwise have eaten into baseload (Figure 26) could be stored and spread across the day (Figure 27). While the quantum of baseload is smaller than pre-solar times, at least some 'true baseload' does actually exist (i.e. plant which runs almost all year round) rather than with the uneconomically low load factors described earlier. Under this storage scenario, baseload technologies (nuclear and coal) would benefit at the expense of gas, as storage provides the 'flex' in the system previously provided by gas.

Figure 26. Generation profile before storage



Source: Citi Research

Figure 27. Generation profile once storage is installed



Source: Citi Research

So, solar initially steals peak demand from gas, then at higher penetration rates it steals from baseload (nuclear and coal) requiring *more* gas capacity for flexibility, but then with storage, it benefits baseload at the expense of gas. Who would want to be a utility, with this much uncertainty?

Storage is in its infancy and is only likely to impact highly developed markets at the margin

We would highlight, however, that while energy storage is a rapidly growing market, it is still in its infancy in global terms, and is only likely to impact highly developed markets such as Germany at the margins, and that it will need subsidies to allow the industry to develop given that storage solutions are still expensive and largely uneconomic. Nevertheless, increasing amounts of capital are being deployed in the industry. Much of the historic investment in battery storage technology has been in the automotive sector given the development of electric vehicles. However, increasing efforts are being made elsewhere, most notably for the purposes of either small-scale residential storage (via the integration of Li-ion batteries into the inverters which convert solar electricity from DC to AC), or at a grid level. It is important to note that while the holy grail for the automotive industry has been maximising energy storage capacity while reducing weight (electric vehicle batteries are enormously heavy, and thereby affect range, performance etc), at a residential or grid level, size and weight is far less of an issue. The industry is still at that exciting (and uncertain) stage where there are many different competing technologies, and it is not yet clear which will emerge as winner(s). At a grid level investments are being made into compressed air storage, sodium sulphur batteries, lead acid batteries, flow batteries, Li-ion batteries, and flywheels to name a few. These are all discussed in more detail in the report highlighted below.

So while storage is still very much a nascent industry, we should remind ourselves that this was the case with solar in Germany only 5-6 years ago. The increasing levels of investment and the emergence of subsidy schemes which drive volumes could lead to similarly dramatic reductions in cost as those seen in solar, which would then drive the virtuous circle of improving economics and volume adoption.

For a more detailed discussion of the issue of energy storage and its potential impact on the electricity markets, see our recent publication: Battery storage – the next solar boom? - Germany leads the way with storage subsidies.

Summary

Energy markets are evolving, and faster than expected

So, changes are happening fast in both developed and emerging markets and there are a huge number of variables that will affect whether peaking gas wins at the expense of coal and nuclear baseload, or vice versa and in which geographies around the world. These changes will affect the returns (both positively and negatively) not just of utilities, but also of upstream fossil E&P companies in terms of demand and hence pricing and returns on investment, and for equipment manufacturers in terms of demand for power generation equipment. While much of demand will remain unchanged, most notably oil for transportation and the 60% of gas which goes directly into industry and heating, what is important in our analysis in this report is the **incremental** supplies to meet demand growth, and which energy choices are used to meet that increased demand based on our integrated cost curves.

Focus on the power generation market

As discussed, the power generation market is the focus of this report, being by far the largest and fastest growing of the primary energy end-use markets, as well as the most fungible in terms of technologies and fuels.

To analyse the changing face of the generation market, we have split the traditional oil & gas cost curve into a gas curve (as very little oil is used in power generation), and produced a corresponding LCOE (levelised cost of electricity) curve for gas, and done the same with our coal cost curve, and derived similar curves for wind and solar.

Citi integrated energy cost curve allows comparison by individual energy asset

By examining the power generation 'cost curves' by individual source project (i.e. the curves are made up of each individual gas and coal field), we can examine the risk to specific upstream investment in a more holistic manner than we believe has been attempted before.

Gas: The shale (r)evolution

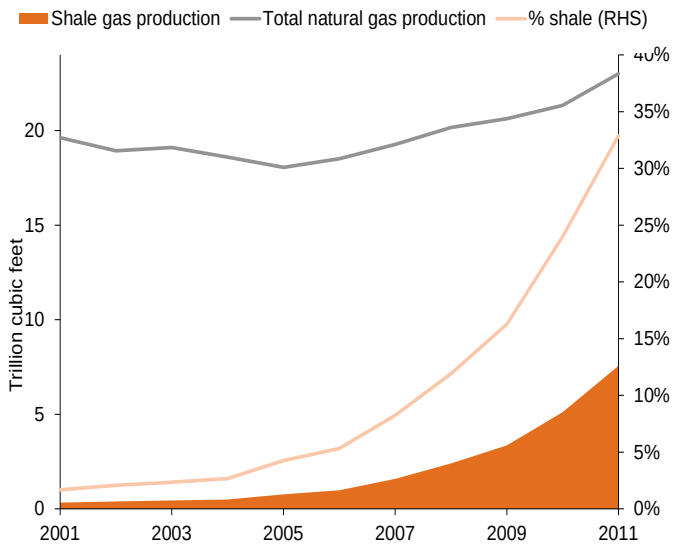
The advent of shale gas has nothing short of revolutionised the global energy mix, and the economic fortunes of those countries lucky enough to have been blessed with extensive reserves — while penalising those less fortunate. It has changed the shape and levels of the oil & gas cost curve, with a corresponding impact on the economics of many competing assets, for example, by impacting the traditional oil-gas price linkage, and negatively impacting the price of displaced coal. In this chapter, we examine the winner and losers, the knock-on effects of shale on other commodities, and most importantly derive the gas cost curve.

The biggest effect from shale gas to date has been in the U.S., where an already well developed oil & gas industry combined with attractive geological characteristics meant that this shale has been the first to be developed extensively and some of the cheapest to extract. Shale gas now accounts for a third of total U.S. natural gas production, more than compensating for the decline in conventional natural gas production. The boom in shale gas production has allowed the U.S. to reclaim its place as the world's largest natural gas producer, edging out Russia, with a sizable lead over all the other major gas producers (Figure 29).

In the last seven years, the U.S. has witnessed a remarkable growth in shale gas production, from less than half a tcf produced in 2005 to over 7.5 tcf produced in 2011 (Figure 28).The spectacular rise of shale gas production has transformed shale gas from a marginal source of natural gas – contributing under 3% of the supply in 2004 – to one of the most important sources, accounting to around a third of the total US natural gas supply.

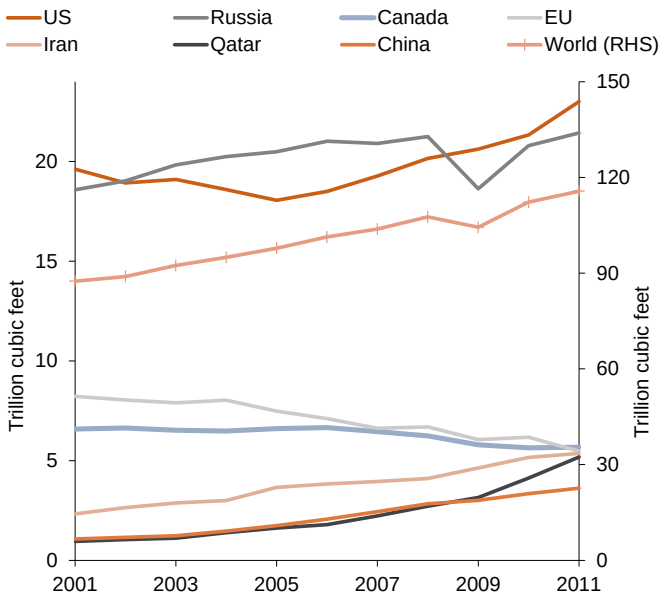
The exploitation of shale gas has led to a renaissance in total U.S. natural gas production since 2005. Reversing a decade-long decline, production has risen from a low of ~18 tcf in 2006 to a record high of ~23 tcf in 2011.

Figure 28. U.S. shale gas production has boomed since 2005



Source: IEA, BP Statistical Review of World Energy, Citi Research

Figure 29. U.S. has overtaken Russia as the largest natural gas producer



Source: IEA, BP Statistical Review of World Energy, Citi Research

U.S. shale gas production is forecast to continue its boom in the next 25 years…

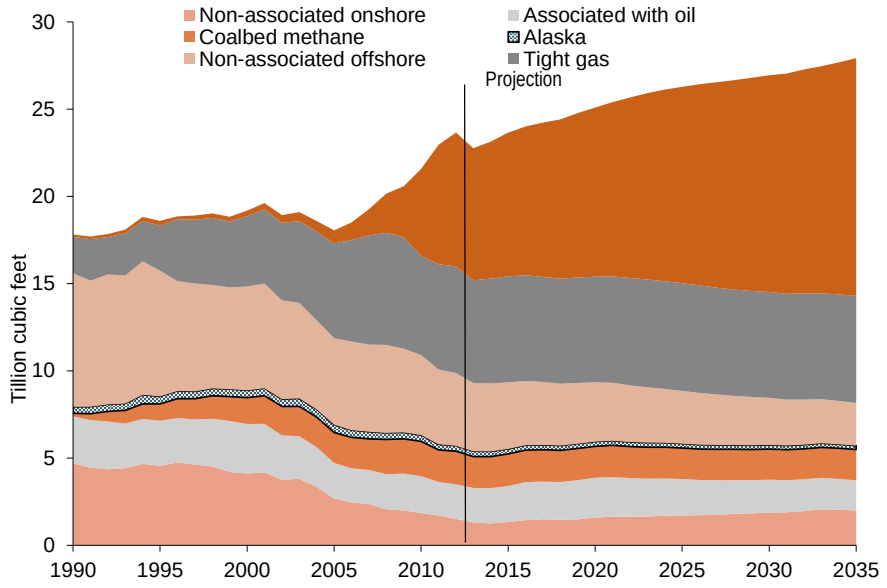
U.S. shale gas production is expected to continue its growth in the medium term, reaching 14 tcf by 2035 according to the US Energy Information Administration (EIA). This would position shale gas as the dominant source of natural gas in the U.S., accounting for ~50% of the total U.S. natural gas supply of ~28 tcf (Figure 30).

…more than offsetting declines in the production of natural gas from conventional sources…

The production of natural gas from conventional sources in the U.S. has slowed in recent decades as traditional natural gas fields become steadily depleted, and this gentle decline is expected to continue into the future. Without the boom in shale gas production, total U.S. natural gas production would have continued its decline, and by 2035 would have fallen to under 14 tcf.

The scale of the shale gas boom, then, is the difference between total 'conventional' natural gas production in 2035 of 14 tcf and **twice** this quantity; an enormous discrepancy that is shaking up the U.S. energy landscape.

Figure 30. Shale gas is forecast to take an increasing share of U.S. natural gas production



Source: EIA, Citi Research

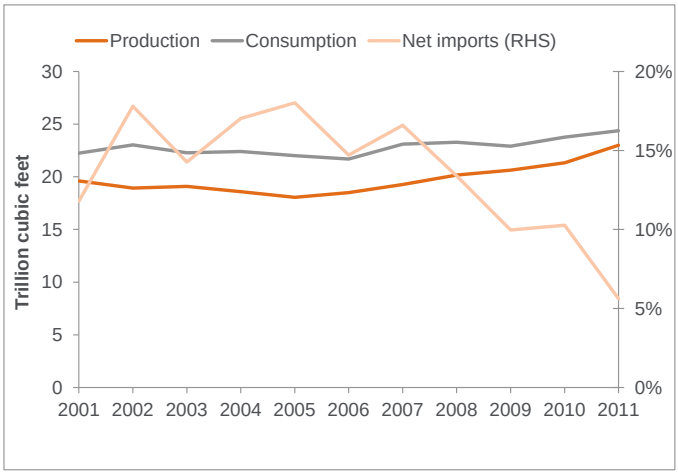
…and is likely to transform the U.S. from a net importer of natural gas to a net exporter of natural gas…

The effect of the shale gas boom can be clearly seen in the decline of US natural gas imports, and the changing fate of U.S. policy towards LNG. Just a decade ago, the U.S. imported up to 18% of the amount of natural gas that it consumed (Figure 31), mostly from Canada, and was bracing to become a large importer of LNG in the near future. In anticipation, the U.S. began the construction of several LNG re-gasification terminals (for import) in the Gulf of Mexico. At the same time, the export of natural gas was highly regulated by the U.S. government, in an attempt to protect domestic supply.

Since 2005, however, the import rate has fallen sharply, and in 2012 sat at just 5.6% of U.S. natural gas consumption. Consequently, the U.S. now expects to become a net exporter of natural gas in the near future. To accommodate this, the U.S. is in the process of approving export licenses for several LNG liquefaction terminals (for export). Moreover, the re-gasification terminal at Sabine Pass is being converted to a liquefaction terminal.

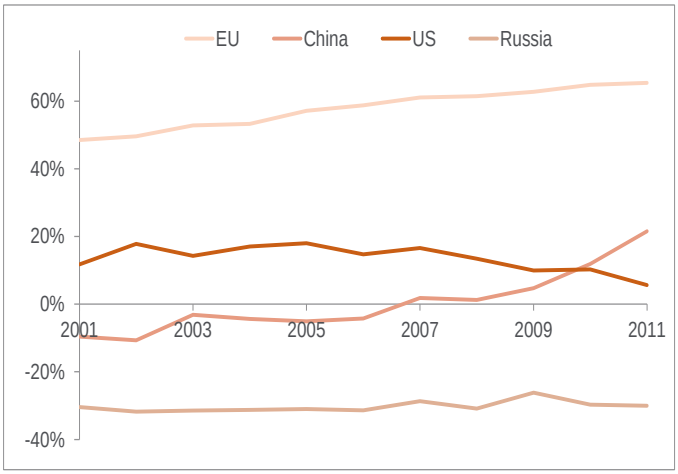
The fall in U.S. natural gas imports contrasts with the fortunes of the EU, which now imports over 60% of its natural gas, and China, which in the last 10 years has shifted from being a net exporter of natural gas, to being a large net importer (Figure 32).

Figure 31. U.S. natural gas production, consumption and net imports as a percentage of consumption



Source: Citi Research; BP Statistical Review of World Energy

Figure 32. Net imports (or exports) of natural gas as a percentage of natural gas consumption (or production)



Source: Citi Research; BP Statistical Review of World Energy

One of the immediate consequences of this 'technology change' in the gas industry has been dramatically lower gas prices in the U.S., where the Henry Hub natural gas price benchmark fell from its recent peak of $13.28/MMBtu in early July 2008 to a low of $1.89/MMBtu in April 2012, before a recent rally to $3.75/MMtu. Critically, the price has been under the bar of $5/MMBtu since January 2010, a price that had not been seen since 2002.

Comparing this with gas importers such as Japan, which in the wake of the Fukushima incident has been importing gas at up to $16-17/mmbtu, the impact on energy prices and industrial competitiveness is abundantly clear. In the light of this, Japan has introduced the most attractive feed-in tariff in the world for solar installations in an attempt to diversify its energy mix away from expensive fossil fuels. This has seen Japan leapfrog others to become the second largest solar market in the world, only marginally behind China (Citi forecast 2013 Japan installations of 7GW, from 2GW in 2012A, vs. China Citi forecasts 2013 8GW).

Once again this shows the potential speed of energy substitution in response to price moves (a secondary effect in Japan's case, but essentially still the driver).

…leading to increased industrial use of natural gas, especially in the electricity sector

As the gas price has fallen in some markets, the economics of gas-fired electricity have become markedly more favourable. As the 'spark spread' has risen above the 'dark spread', the marginal cost of gas-fired power has fallen below that of coal-fired power, causing U.S. utilities to fire up their gas-fired plants at the expense of coal-fired electricity.

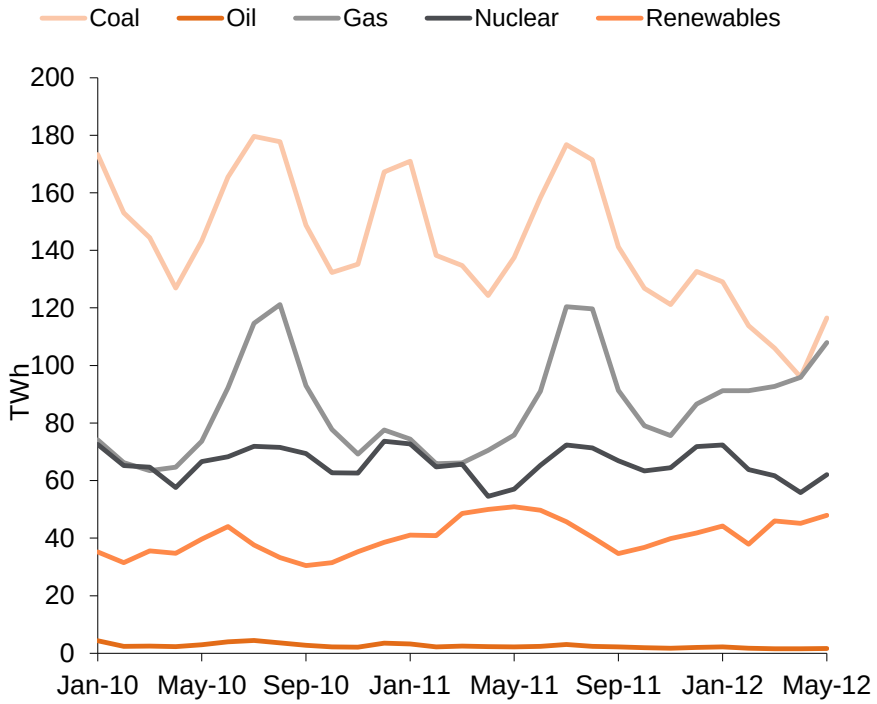
What are spark, dark, and quark spreads?

A spark spread is the difference between the cost of gas used to generate a unit of electricity, and the selling price of that unit, i.e. the gross margin of a gas-fired power plant. A dark spread is effectively the same measure but for coal fired generation, with quark spreads referring to nuclear generation.

Gas and renewable generation offsetting coal

Over the last couple of years, this switching trend from coal to gas has accelerated markedly, so much so that in April 2012 the U.S. generated as much electricity from gas-fired plants as from coal-fired plants (Figure 33), a first for the U.S. Though some of this effect was seasonal (and economic), the short-term shift away from coal-fired power to gas-fired power is pronounced. Potential changes to emissions laws could exacerbate this switch further. While still small in relative terms, the gradual rise of renewable energy as a part of the energy mix in Figure 33 should not go unnoticed.

Figure 33. U.S. electricity generation by sources



Source: EIA, Citi Research

Coal remains more attractive for existing power generation in Europe

Regional pricing differentials however dictate that the opposite has been true in Europe. The relative economics of other types of generation have proved more attractive, most notably coal where Russian and US coal exports to Europe (driven by an increased use of U.S. shale for domestic generation freeing up coal for export) have kept the European market well-supplied. Combined with low carbon prices, this has made coal much more competitive than gas in power generation. This has been exacerbated by gas prices that have remained high, likely on supply concerns and demand for storage injection, which have also put heavy gas-consuming industrials at a particular disadvantage compared with their counterparts in the U.S. who are benefiting from very low gas prices.

Japanese demand for gas likely to stay flat longer term

The shutdown of Japanese nuclear that spurred the surge in LNG imports should gradually fade, as more nuclear units are likely to restart in the longer term. Unless massive infrastructure investment were to take place, the current gas and power transmission systems could restrict the fuel mix possibilities that Japan can pursue. Currently Japan still has to rely on oil-fired generation to fill part of the gap left by the loss of nuclear units, as a lack of infrastructure prevents gas-fired generation from fully substituting the loss of nuclear capacity, thereby limiting Japan's demand growth for LNG. The infrastructure issue mainly involves the lack of pipeline/storage network on the gas side, and the lack of connectivity of the power grid between the 10 utilities, where electricity frequencies are different from company to company. These issues should continue to limit the flexibility of energy supply, affect what and where power plants can be built, and influence how plants are connected.

Global shale gas reserves: Who stands to benefit?

Although shale reserves exist around the world, the quantity and quality of the recoverable natural gas from these assets is far from certain. The first comprehensive study of shale reserves conducted in 2011 by the EIA put global technically recoverable reserves (TRR) at an extremely promising 6,600 tcf, though subsequent studies have not been so generous.

Big winners are gas importers with extensive shale reserves…

However, not all countries are equally blessed with shale gas resources. In our view, the big potential winners of the shale gas boom are those countries which both have significant shale gas reserves *and* that are either: 1) currently or potentially heavily reliant on natural gas imports (China, U.S., Mexico, South Africa, Canada, Brazil, Poland, France and Ukraine), or; 2) exporters of natural gas whose conventional reserves are rapidly depleting (Canada, Algeria and Norway).

…vs. the losers without

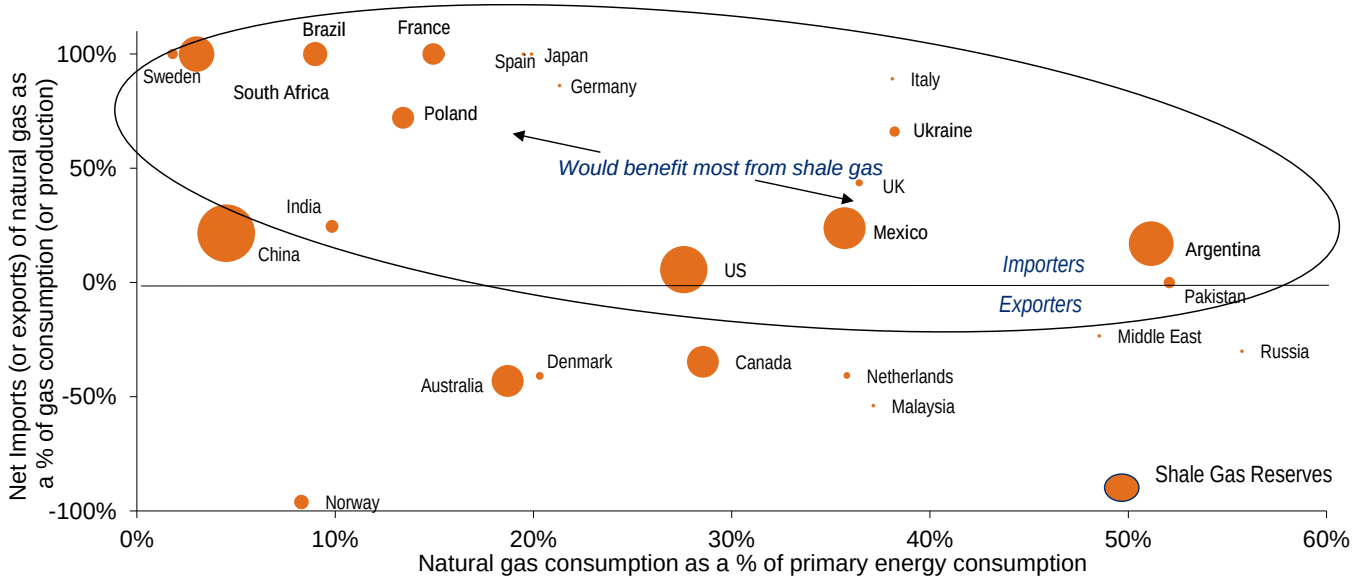
By contrast, the big potential losers are those that do *not* appear to have significant shale gas reserves and which fit into the two above categories: 1) Germany, Japan, Italy, Spain and to some extent the UK, or; 2) Malaysia, Trinidad & Tobago, Egypt and Uzbekistan. Note, however, that this would change if significant shale gas resources were discovered in any of these countries.

One group of countries that would benefit most from possessing shale gas resources are those which are currently, or potentially, heavily reliant on natural gas imports. To screen for current reliance, we look for countries in which natural gas is a large proportion of the primary energy mix, and that import a large proportion of the natural gas consumed (Figure 34).

On these measures, **China, US, Argentina, Mexico, South Africa**, **Canada, Brazil, Poland, France** and **Ukraine** are the big winners from shale gas. Australia adds shale reserves to an already strong asset/export position.

On these measures, **Japan, Germany, Italy, Spain** and to some extent the **UK** are the big losers from shale gas, as they would have benefited most from shale gas resources but do not appear to possess significant quantities.

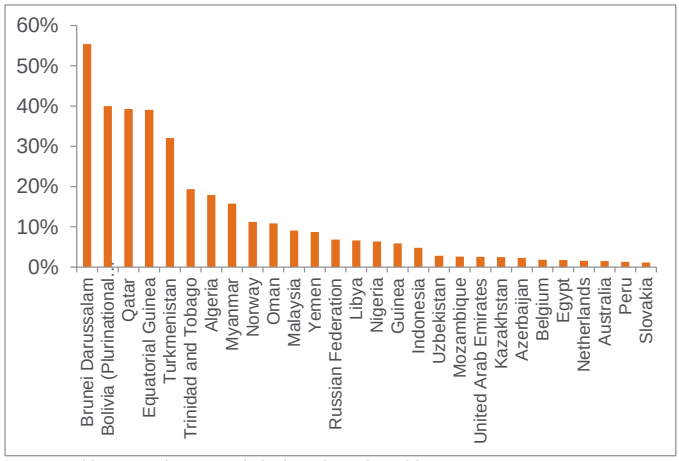
Figure 34. Location of shale gas versus natural gas consumption and imports



Source: IEA, BP Statistical Review of World Energy, Citi Research

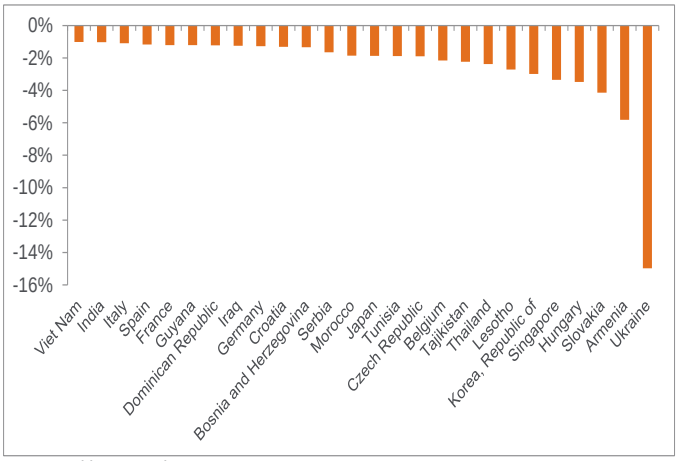
Figure 35 and Figure 36 show these exports or imports as a percentage of GDP, to give a sense of the scale of economic important to the country.

Figure 35. Net gas exports as % of GDP: Exporters



Source: Citi Research, BP Statistical Review of World Energy, IMF

Figure 36. Net gas exports as % of GDP: Importers

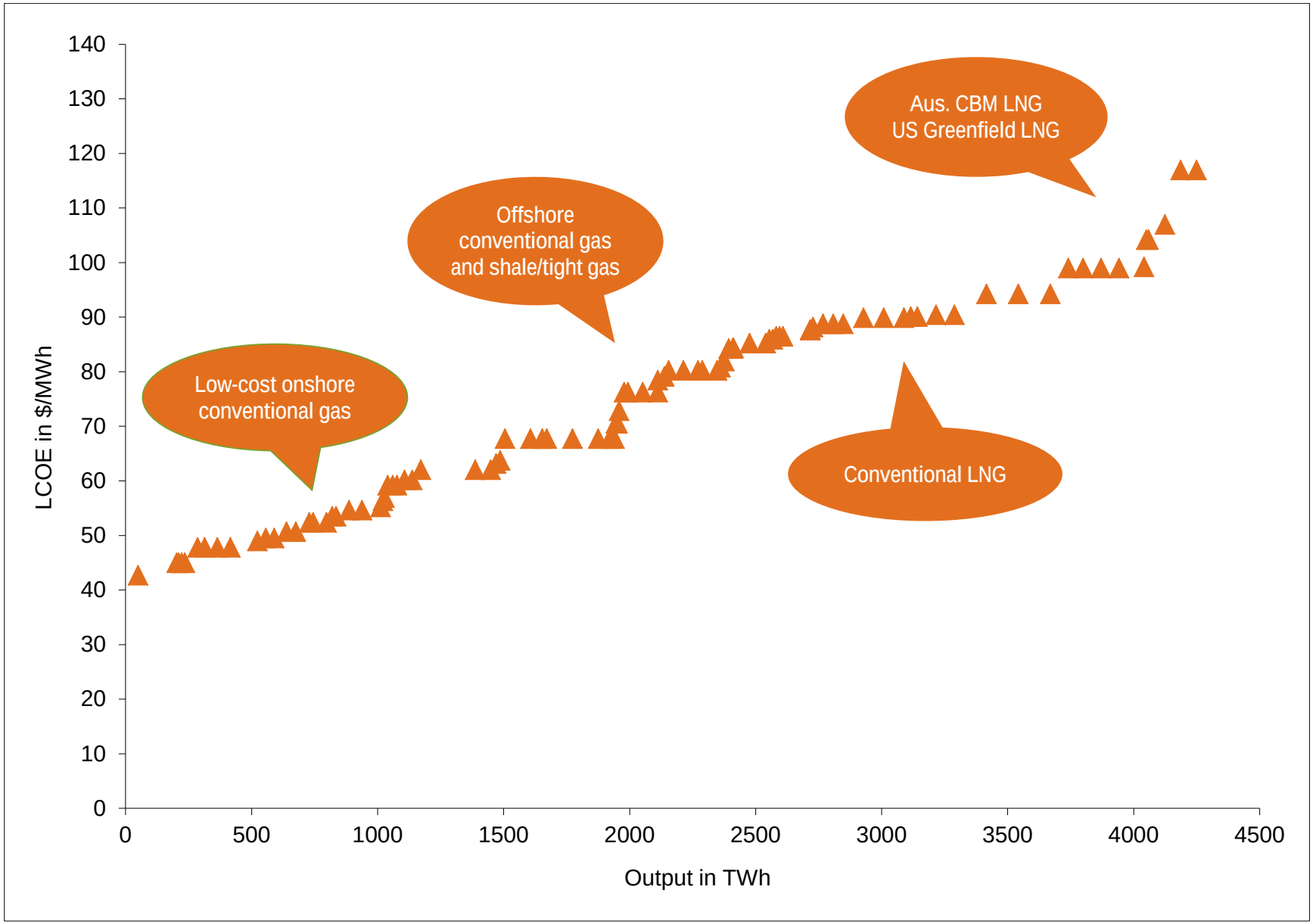


Source: Citi Research, BP, IMF

Generation of a gas cost curve, with shale dominating in the first quartile

Shale has dramatically altered the shape and extent of the gas cost curve. Applying our LCOE approach to the gas cost curve produces the curve by upstream project shown in Figure 37, which will later be combined with those for other fuels and technologies. As before, it is important to note that this curve is generated using the estimated production costs of incremental gas assets coming onstream between now and 2020. The assumptions behind their conversion into LCOE are explained at a high level in the appendices in this report.

Figure 37. LCOE cost curve for gas fired generation by upstream project – best case scenario



Source: Citi Research

Shale gas and commodity prices

Breaking the link to oil

Gas contract prices have historically been linked to the oil price, and in many cases still are; however, shale is gradually changing that, as dissatisfaction with gas prices indexed to oil grows in gas importing countries. Why should gas still be indexed to oil given that production costs are different, and that gas has its own supply-demand fundamentals? What's more, natural gas today is essentially a primary energy source for electricity generation while petroleum is essentially a transportation fuel and the evolution of each of these sectors is what should challenge the indexed linkage.

US Shale is impacting global coal prices

Gas itself has started to have a material impact on global commodity markets given that it is already causing its own substitutional effects. As discussed earlier, the increased use of gas in U.S. power generation (alongside increasing renewable production) has reduced demand for coal, thereby freeing that coal up for export. This in turn has reduced coal prices, making it far more attractive for generation in Europe, especially given markedly higher gas prices. Gas prices have remained high in Europe and Asia, not least due to the previously mentioned nuclear-shutdown-driven Japanese craving for LNG.

Gas markets are increasingly spot-priced

The U.S. and Canada are already on a spot pricing basis. A growing amount of European gas is procured in the spot market, further reducing the demand of oil-indexed contract gas. Asian gas price gains could be reversed due to gas-indexed U.S. exports, the potential restart of more Japanese nuclear units and the reluctance of China and India, the two biggest growth countries, to accept steep oil-indexed prices.

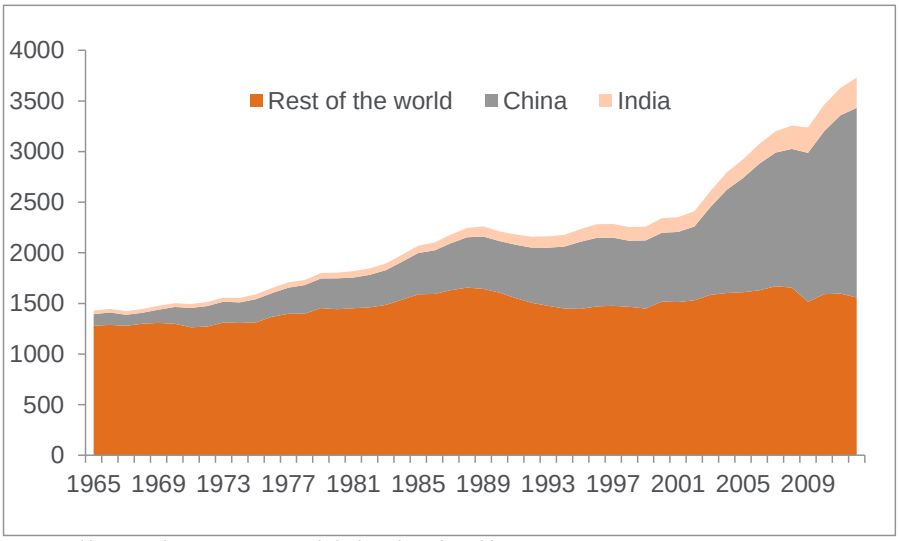
The impact of U.S. Henry Hub gas pricing has already been transmitted globally through three ways:

- Outright exports of U.S. LNG - exports linked to Henry Hub prices are the most direct way of transmission.
- Exports of U.S. coal are another way of transmitting Henry Hub pricing globally. With the shale gas production boom, thermal coal, particularly Eastern U.S. Appalachian coal, is being displaced by natural gas in the power generation sector. U.S. coal prices have similarly fallen as gas prices fell, but as U.S. gas prices rose, coal prices also rose. Nonetheless, the excess coal is being exported to Europe but also in part to Asia, including China. The delivered cost of coal in Europe and Asia could effectively set a soft ceiling on coal prices, as the U.S. is the swing thermal coal supplier globally. In places where coal and gas compete with each other in the power sector, lower coal prices make coal-fired generation more competitive, displacing gas-fired generation.
- LNG diversions from the Atlantic Basin to elsewhere globally. LNG liquefaction terminals that initially have the U.S. market in mind, as the U.S. was still perceived to be short gas supply up until 2008/9, instead have been delivering LNG cargoes to Europe and Asia. Before Fukushima tightened the global LNG market, excess cargoes had been pushing down prices, causing stress on oil-indexed pricing. Fukushima tightened the market, but low European demand from strong coal generation due in part to U.S. coal exports pressuring coal prices, as discussed above, reduces LNG demand. Cargoes were diverted to Asia from Europe. An increasing amount of diverted cargoes pushed down the Asian LNG price from a high in the $18/MMBtu to $13/MMBtu before recovering to the middle of this range as winter approached.

Coal: Survival of the fittest

The coal industry is evolving more slowly than other energy sources, which questions its future participation in a rapidly changing energy world. Global coal consumption, ex China and India, has essentially been flat since 1965 and the latter two countries have represented over 100% of the world's demand growth (Figure 38).The consensus outlook for coal, which has largely been based on china's ever-increasing coal demand, has the IEA calling for coal to surpass oil as the leading global fuel source before 2030. However, Citi believes that the transformative forces in the global power mix are likely to disrupt this consensus view. Changes in the power mix, especially in China, could have a significant impact on 1) global traded coal, 2) countries and companies that are reliant on coal production, and 3) carbon emissions. In this chapter, we examine the dynamics in the global coal market in terms of both supply and demand, in particular the prospects for plateauing or declining demand in China, and most importantly derive our global coal cost curve.

Figure 38. World coal consumption, Mtoe



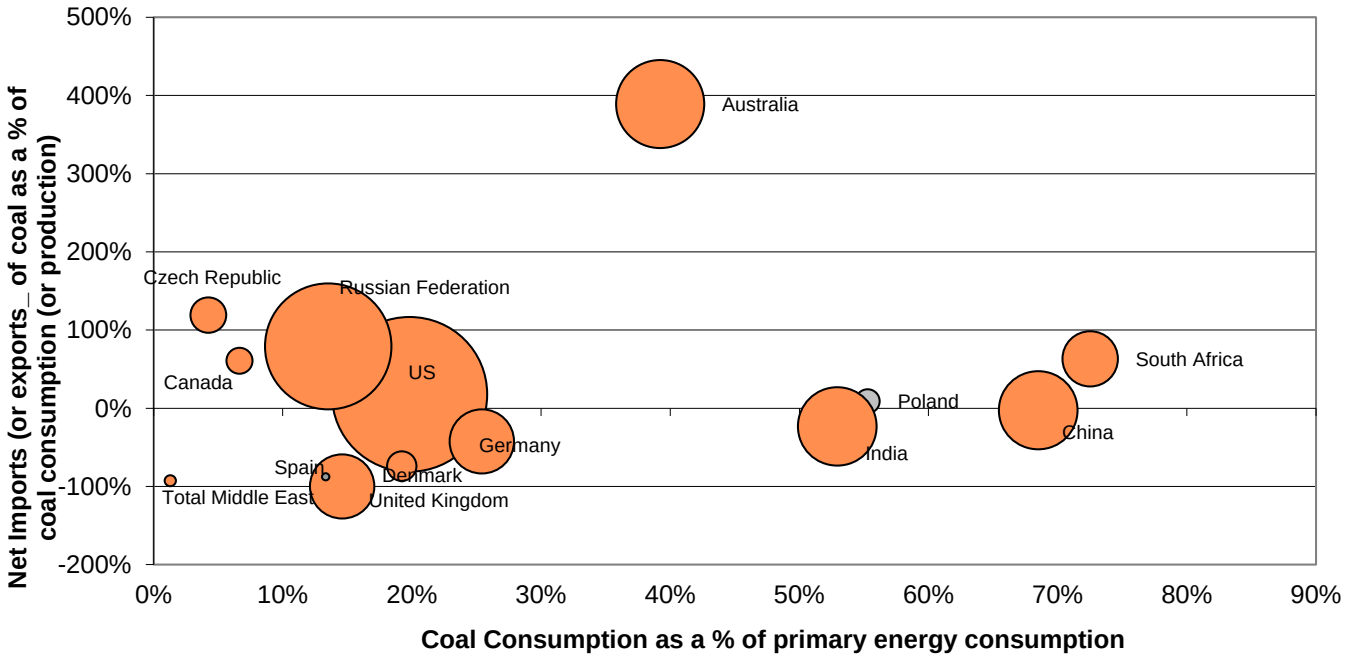
Source: Citi Research, IEA, IEA, BP Statistical Review of World Energy

China and India have dominated growth in demand for coal

As our section, 'Lessons from history' discusses, coal evolved as the primary energy source during the industrial revolution due to its availability, high energy content (compared to wood fuels), and its ability to be utilised in steam engines (power and transport). While coal usage for transportation has died out, being replaced by oil (which in turn is being threatened by gas), it continues to play a dominant role in power generation. Since the 1970's, environmental issues have been increasingly important particularly around open pit mining, air pollution, and the contribution coal has to green-house gas emissions.

Low cost and abundance has been the main driver of coal demand in India and China, both countries have been able to utilise their large coal reserves to maintain a large percentage of their primary energy mix as coal. In contrast, developed markets have seen falling coal rates as a proportion of their overall primary energy mix. More recently both India and China have moved to be coal importers over the past few years given strong economic growth; however, this balance could shift in the coming decade.

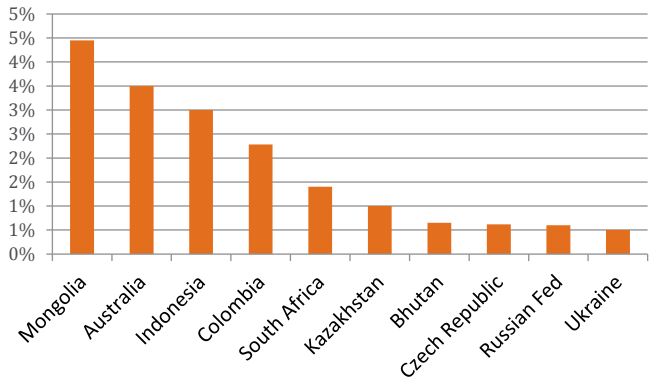
Figure 39. Location of coal reserves versus coal consumption and imports



Source: Citi Research, IEA, IEA, BP Statistical Review of World Energy

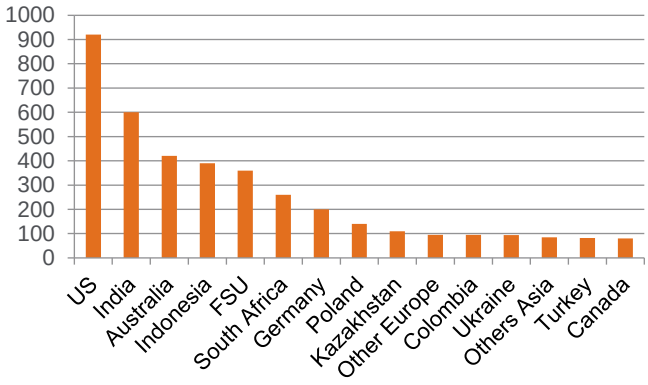
While Figure 39 puts the dependence on imports and the importance of consumption in a relative context (and is designed to be viewed in conjunction with Figure 34 for gas), the absolute export figures are given in Figure 41.

Figure 40. Coal export value as share of a country's GDP in 2011



Source: UNCTAD, Citi Research
Note: These export figures include metallurgical coal, but the magnitude illustrates how much a country is reliant on coal exports as a part of GDP

Figure 41. Top 15 coal producing countries in 2012 (ex-China)



Source: BP, Citi Research
Note: China produced 3,650-MM tons of coal in 2012

The coal arbitrage

Two distinct seaborne coal markets, the Atlantic and Pacific…

The global traded seaborne market for coal has evolved into two distinct regions: the Atlantic and the Pacific.

Atlantic

The Atlantic region has developed into Europe being the major importer with the supply coming from North American, Africa (predominately South Africa) and growth out of South And Central American (predominately Colombia).

…are each driven by local effects

The market has been characterised by a structural pick up in volumes from Columbian coal, while South African exports have been hampered by legacy port constraints and North America has been viewed as the swing producer. South Africa is largely the swing supplier between the Pacific and Atlantic basins, based on freight differentials.

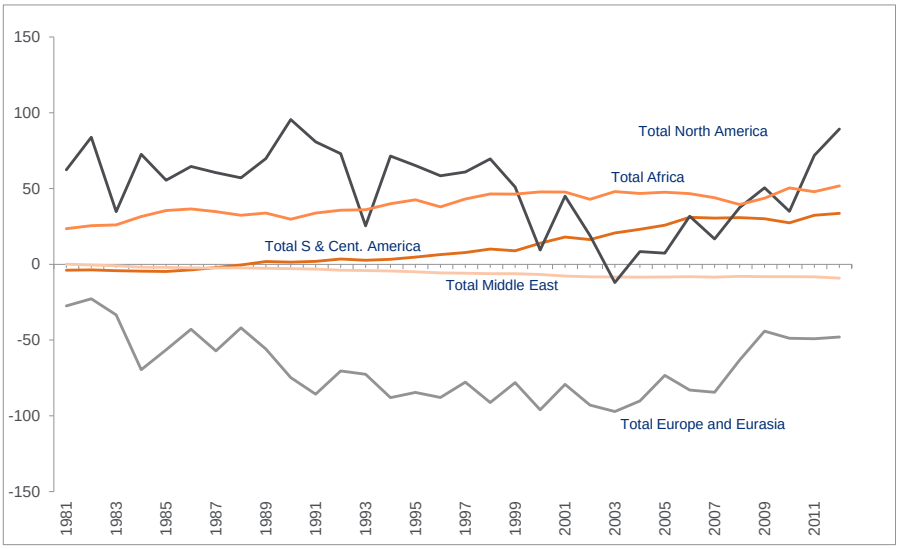
European demand has also fallen due to stagnant demand from key coal importing countries such as the UK, Germany and France and a pick up from Russian exports.

Figure 42. Europe and the long short coal (mtoe)

Czech Republic	4.1
Denmark	-2.5
France	-11.3
Germany	-33.5
Italy	-16.2
Norway	-0.7
Poland	4.9
Portugal	-2.9
Romania	-0.3
Russian Federation	74.2
Spain	-16.9
Sweden	-1.5
United Kingdom	-28.9

Source: Citi Research

Figure 43. Atlantic market net traded (production – consumption), Mtonnes oil equivalent

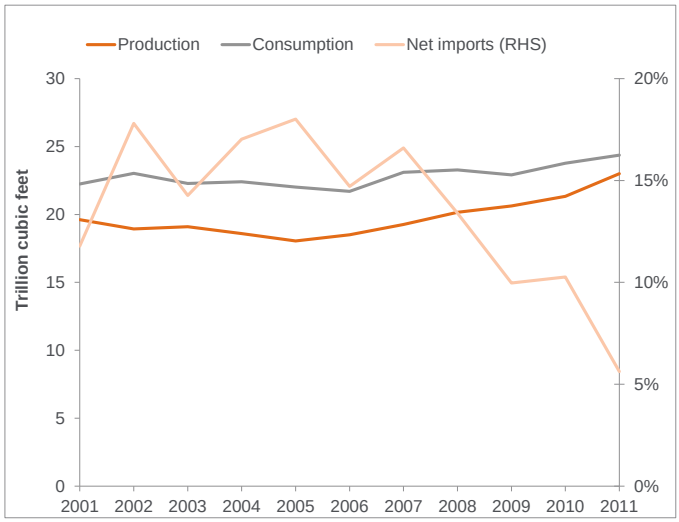


Source: BP Statistical Review of World Energy, Citi Research

Shale has impacted the coal markets

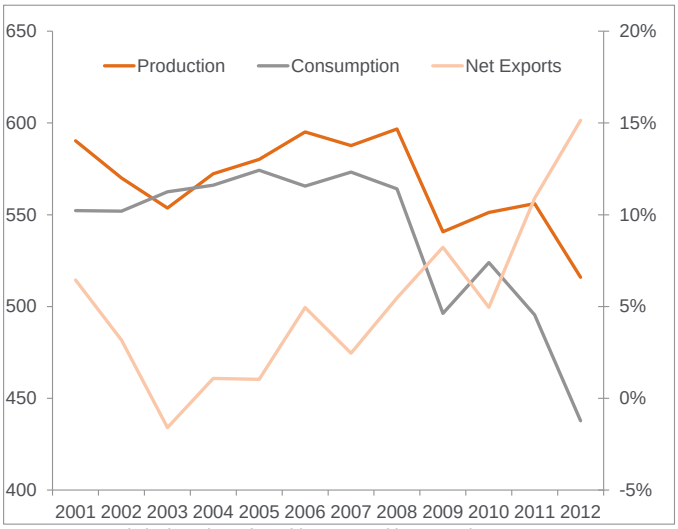
The U.S. shale gas revolution not only sparked a major shift change in the Atlantic region which has had ripple effects in the Pacific region. The U.S. flipped from being a net importer of both natural gas and coal, to being an exporter of coal. The U.S. imported around 2% of their coal need in 2003, and this has now moved to the U.S. exporting around 15% of its coal consumption in 2012.

Figure 44. U.S. natural gas production, consumption and net imports as a percentage of consumption



Source: BP Statistical Review of World Energy, Citi Research

Figure 45. U.S. coal production and consumption Mtonnes of oil equivalent as a percentage of consumption

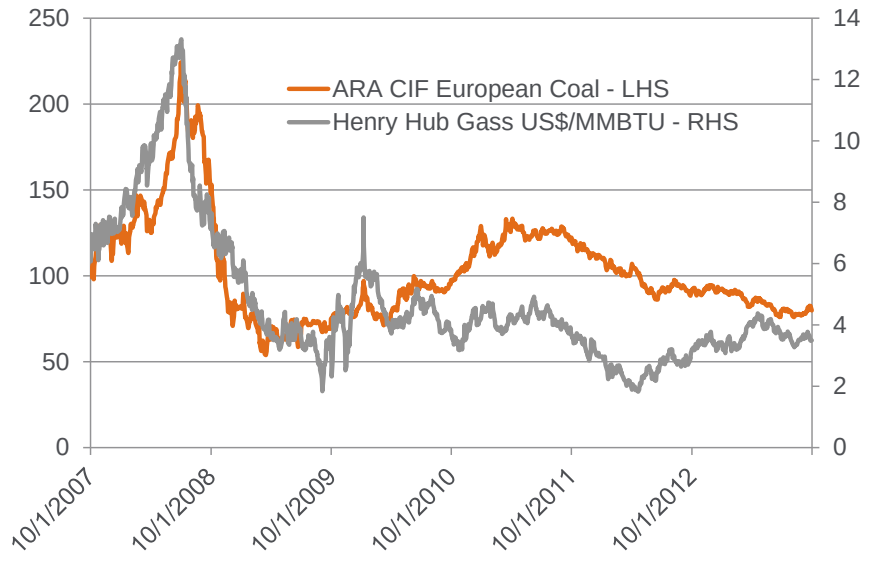


Source: BP Statistical Review of World Energy, Citi Research

Gas into coal – more substitutional effects

In essence, the shale gas revolution sparked US coal producers to push volumes into the Atlantic region which had a knock on impact on prices across the globe.

Figure 46. Henry Hub gas prices versus European coal prices



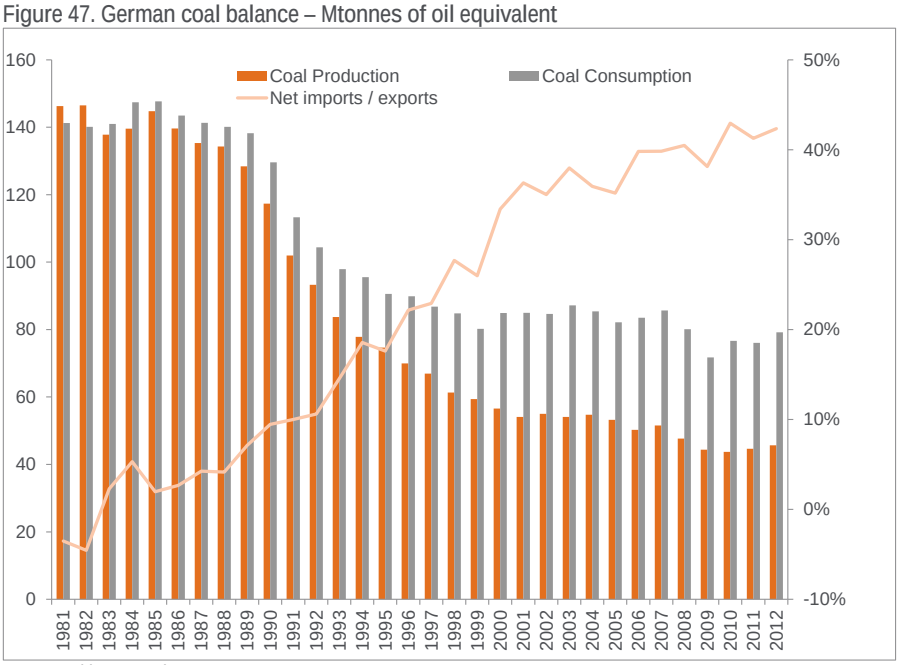
Source: Citi Research

European demand – Germany, a case example

Germany is willing to run coal, but not to build new capacity

Germany's dependency on coal has fallen, but its imports of coal have increased steadily over the past decade. Arguably, as coal has remained the cheapest fuel source, it has been a key factor in base load consumption. Nevertheless, what is interesting is the negative growth rate which has occurred over the past thirty years, which gives some indication that European utilities are happy to run coal fired power stations but unwilling to commit to building more of them.

Figure 47. German coal balance – Mtonnes of oil equivalent

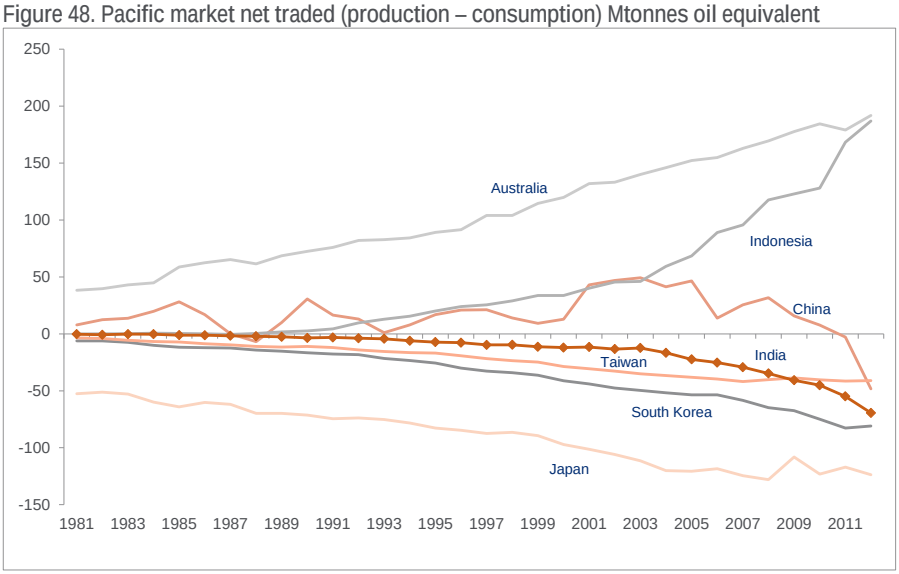


Source: Citi Research

Pacific

The global thermal coal market has been dominated by China and India on the demand side. On the supply side, it has been a case of growth from Indonesia and Australia with the former showing very rapid growth rates over the past ten years. Arguably what happens in these two countries is likely to define global coal trade and prices for the coming decade.

Figure 48. Pacific market net traded (production – consumption) Mtonnes oil equivalent



Source: Citi Research, IEA, IEA, BP Statistical Review of World Energy

Peak coal in China

'Peak coal' in China would have global implications

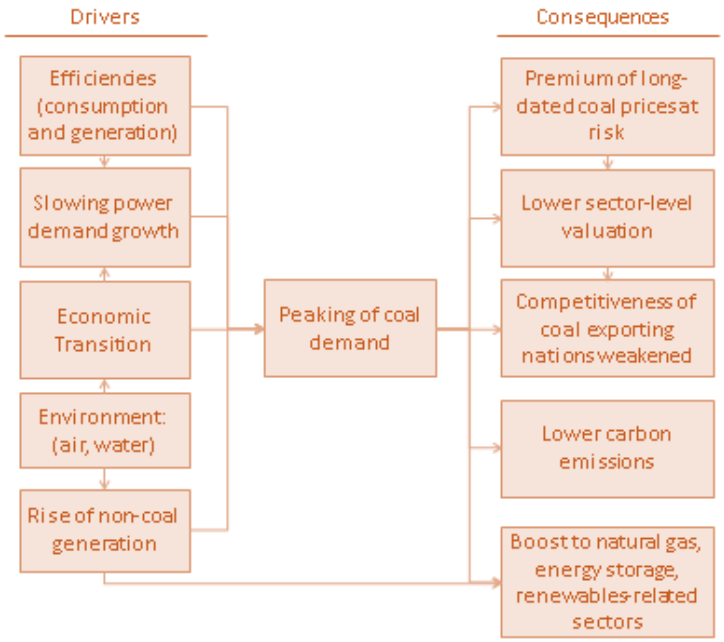
For a more detailed discussion of this topic see our recent report: The Unimaginable: Peak Coal in China - Effects of possible peaking of coal demand in China could ripple across global coal trade, producers and carbon emissions.

For the last decade, one of the most unassailable assumptions in global energy markets has been the ever-increasing trajectory of Chinese coal demand. The consensus outlook for China's coal consumption has been so strong that the International Energy Agency (IEA) has called for coal to surpass oil as the leading global fuel before 2030 in the "Current Policy" scenario.[1]

But significant shifts in China's economy and power sector are now underway that demand a reassessment of Chinese coal's perpetual climb. In this report we argue that **the flattening or peaking of thermal coal demand for power generation in China by 2020** is now a plausible and even likely scenario. The same macro forces that are driving the economic transition and lowering power demand should also sharply decelerate coal's use in other sectors.

[1] International Energy Agency's (IEA) flagship publication in 2012 – the World Energy Outlook (WEO) – laid out several energy scenarios based on different policy implementations. The "**Current Policy**" scenario, effectively the business as usual case (BAU), assumes that "government policies that has been enacted or adopted by mid-2012 continue unchanged." The "**New Policies**" scenario assumes that "existing policies are maintained and recently announced commitments…including those yet to be formally adopted, are implemented in a cautious manner." The "**450**" scenario assumes policies "consistent with having around 50% chance of limiting the global increase in average temperatures to 2C in the long term" will be implemented.

Figure 49. Peaking of Chinese thermal coal demand: drivers and consequences



Source: Citi Research

Key developments that generate this scenario include 1) structural downshifts in China's GDP growth and energy intensity; 2) robust growth of China's renewables capacity; and 3) strong improvements in the efficiency of the Chinese coal power fleet and energy efficiency generally. Even scenarios with comparatively stronger power demand growth and weaker renewables growth still produce substantially slower coal demand growth than many market participants currently anticipate.

Citi's analysis is motivated by two developments:

1. The rate of power demand growth in China is slowing, and structural factors indicate this trend may continue. These include both a slowdown in the sustainable rate of GDP growth as China rebalances and a decline in the energy intensity of China's economy. Such drops in the energy intensity of economic growth typically occur as countries undertake structural shifts from industrial-led growth to more diversified models, as China is now doing. As a result the outlook for Chinese power demand growth is meaningfully slower than it was over the last ten years.

2. The outlook for alternative, non-coal power generation supply continues to surprise to the upside. Mounting environmental pressure (not least due to pollution and air quality becoming a much bigger issue) and increasing willingness of the leadership to prioritise cleaner growth suggests these alternatives are set to meet an increasing share of China's electricity demand. An aggressive policy agenda that pushes a true mix of "all of the above" including nuclear, wind, solar, and hydro is set to add almost 500 GW of new non-coal supply between 2012 and 2020. Recent research from Citi's renewables analysts "Launching on the Global Solar Sector" (Feb 6, 2013) calls for even higher renewables growth, including 103 GW of solar capacity in China by 2020 vs. the IEA-derived forecast of 94 GW. Improved efficiency of coal-fired generation would also use less coal per unit of electricity generated.

Air pollution is a key driver of the switch away from coal

Reducing air pollution is a primary factor in slowing down the demand for coal in China. Coal-fired power plants are one of the major sources of the severe air pollution problem in China, along with tailpipe emissions from vehicles and industrial facilities. While carbon emissions have received more attention globally due to their association with climate change, emissions of sulphur dioxide and nitrogen oxides (byproducts of coal burning) produce more serious problems in the country. These airborne matters and the so-called volatile organic compounds (VOCs) cause acid rain and smog. Along with the fine particulate matter (PM) emitted, particularly PM2.5, these emissions are responsible for serious environmental degradation and health and breathing problems. Emissions were already so bad in the last decade that industrial facilities were shut down ahead and during the 2008 Beijing Olympics, though the problem became even worse after, leading to massive protests.

Recognising air pollution's threat to public health, the environment, competitiveness and social stability, the country's leadership appears to be more resolute in dealing with the problem, as highlighted by President Xi's recent remarks linking the environment and productivity. As stationary sources of emissions, coal power plants are often one of the first places emission reduction measures are targeted in most emission abatement programs globally.

Pilot programs capping coal demand have been implemented in a number of regions

Coal cap policies are being discussed and pilot programs implemented in key regions. The NDRC's coal cap strategy involves working with major coal demand regions in developing plans that limit coal use, boost efficiencies, retire inefficient plants and promote fuel-switching. The strategy also looks to impose stricter rules, emission targets and stiffer penalties for violations, while raising the amount of non-coal generation sources. A few emissions trading systems have also sprung up. Coal cap pilots as part of the "12th Five Year Plan for Air Pollution Prevention and Control in Key Areas" include several key locations: the Pearl River Delta, Yangtze River Delta, Beijing-Tianjin-Hebei region and Shandong city cluster. Part of the strategy also calls for accelerating the retirement of inefficient power generation and other industrial facilities, particularly the coal-burning plants that produce a sizeable amount of air pollution.

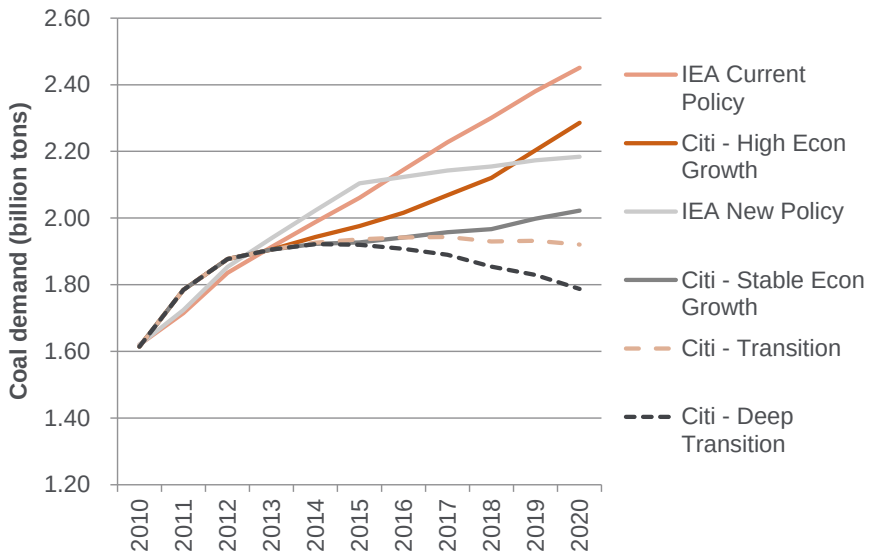
In a sign that demonstrates the commitment by the Central Government to reduce pollution, the Ministry of Environmental Protection temporarily suspended approvals on environmental impact assessments for new construction or expansion of refineries, thereby halting construction. The two largest refiners in the country missed pollution targets and resisted costly upgrades on pollution abatement equipment. In addition to coal-fired electricity generation and energy-intensive industrials, vehicle tailpipe emissions are one of the largest sources of air pollution in China.

We believe coal use in China looks set to plateau or decline this decade

Put simply, if non-coal generation growth outstrips power demand growth, which is already slowing, coal use is set to plateau or decline. This outcome could have significant repercussions across multiple global commodity markets, and now needs to be priced-in into any global energy forecast at a much higher probability than markets currently anticipate.

While global energy agencies continue to expect high coal demand for power generation in the years to come, Citi expects the combination of factors mentioned above should slow the power sector's use of coal, pointing to a flattening or peaking before 2020.

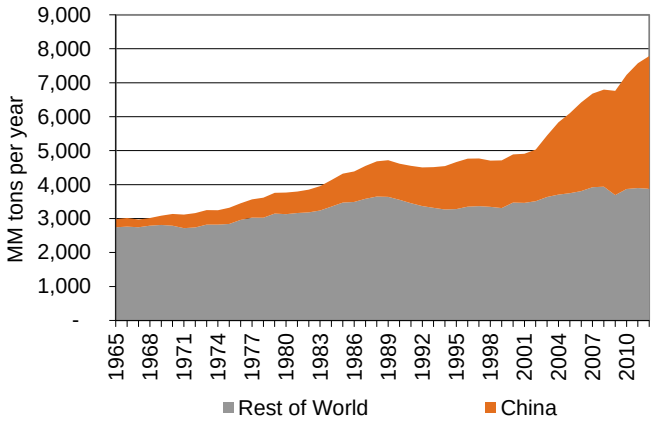
Figure 50. China power sector coal demand scenarios – adjusting expectations lower



Source: IEA, Citi Research

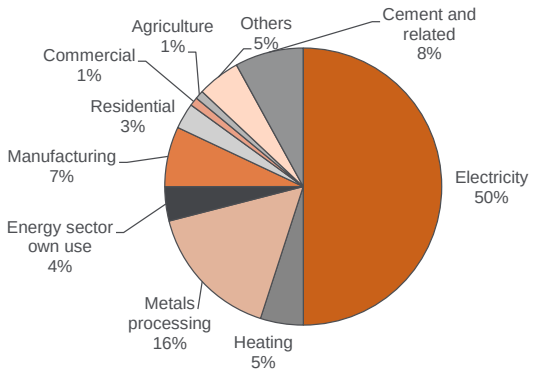
Changes in the generation fuel mix in China would have substantial impact on global fuels market and emissions, as coal demand for electricity generation in China accounts for nearly 25% of world consumption. Besides, electricity demand in China is widely-used as a reliable gauge of the health of the Chinese economy. Over the past 30 years since China opened up its economy, coal consumption surged to power its industries and meet electricity demand. By 2012, Chinese thermal coal demand accounted for over 50% of total consumption worldwide. Within China, 50% of the coal consumed goes into power generation.

Figure 51. The surge in Chinese thermal coal demand has put it over 50% of the world's total consumption



Source: BP, Citi Research

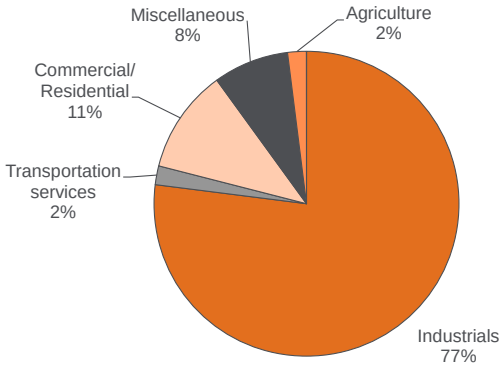
Figure 52. Coal demand for power generation accounts for about 50% of total consumption in China



Source: IEA, Citi Research

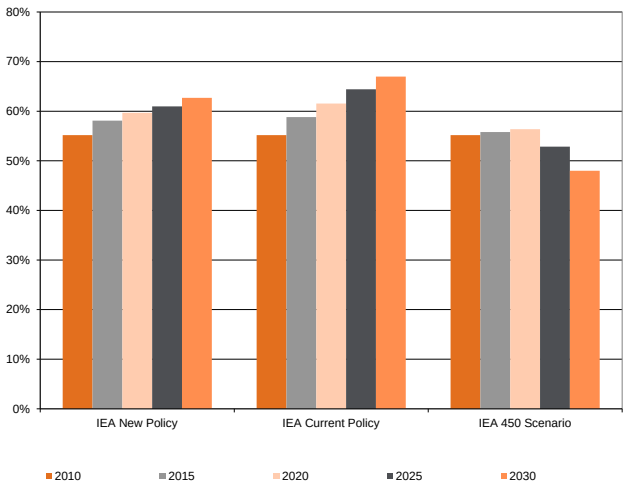
Electricity demand can also be a powerful indicator of non-electricity coal demand. As over three-quarters of electricity demand come from industrials and related sectors, a slowdown in total power demand growth should imply a deceleration in the industrial segment of the economy. With the industrial sector also accounting for nearly one-third of total coal use in China, a slowdown in industrials should lead to weaker coal demand in the non-power sector.

Figure 53. Industrials dominate electricity consumption



Source: IEA, Citi Research

Figure 54. The IEA continues to expect electricity generation to dominate coal demand in China



Source: IEA, Citi Research

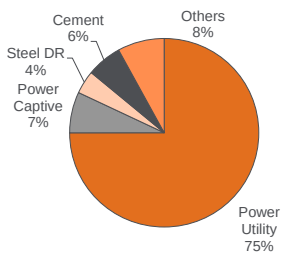
India: A slower growth market

Delays in new-mine clearances and transport bottlenecks stifled domestic thermal coal supply growth to just 2% in fiscal 2009-12. Renewed efforts to increase domestic supply have driven a rebound in dispatch to ~7% growth year-to-date fiscal 2013 for Coal India Ltd (CIL); its production is up 4% (thermal + coking).

Forecasting India imports is complex

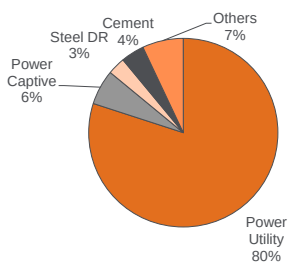
We expect India's total thermal coal supply to grow at a ~6.5% compound annual growth rate (CAGR) in fiscal 2012-15E, slower than a 15% CAGR in underlying demand. To balance supply and demand, imports would have to grow 44% annually. However, forecasting India's imports is complex due to 1) the price spread between higher-cost imports and domestic supply, 2) accumulated losses by SEBs, 3) rupee weakness, 4) logistics, 5) blending constraints, and 6) policy issues. These issues will result in imports continuing to trail underlying demand, based on our analysis.

Figure 55. India thermal coal consumption (FY12E)



Source: Ministry of Coal

Figure 56. India thermal coal consumption (FY15E)



Source: Citi Research

Supply lagging demand

India is the third largest producer of coal globally – 540mt in fiscal 2012 (thermal coal 488mt) from a large resource base of 293bn tonnes (of which coking coal reserves account for 11%; non-coking 89%). Thermal coal production has grown at a CAGR of 2% through FY09-12 impacted by slow clearances – environment, forest, land acquisition and weather disruptions. Dispatch growth has been equally muted due to constraints in rake availability.

While these constraints still exist, CIL's FY13 dispatch growth (YTD) has been ~7% – buoyed by better rake availability; production is up 4% year-on-year.

Our analysis suggests India's total thermal coal supply should grow at a 6.5% CAGR – slower than the rate of demand growth (FY12-15E). We expect domestic thermal coal supply to be 583mt in fiscal 2015 – suggesting a demand supply gap of ~260mt.

Figure 57. Statewise thermal coal production

State	FY12 (488mt)
Chhattisgarh	23%
Orissa	22%
Madhya Pradesh	15%
Jharkhand	12%
Andhra Pradesh	11%
Maharashtra	8%
West Bengal	5%
Uttar Pradesh	3%
Meghalaya	1%

Source: Provisional Coal Statistics 2011-12

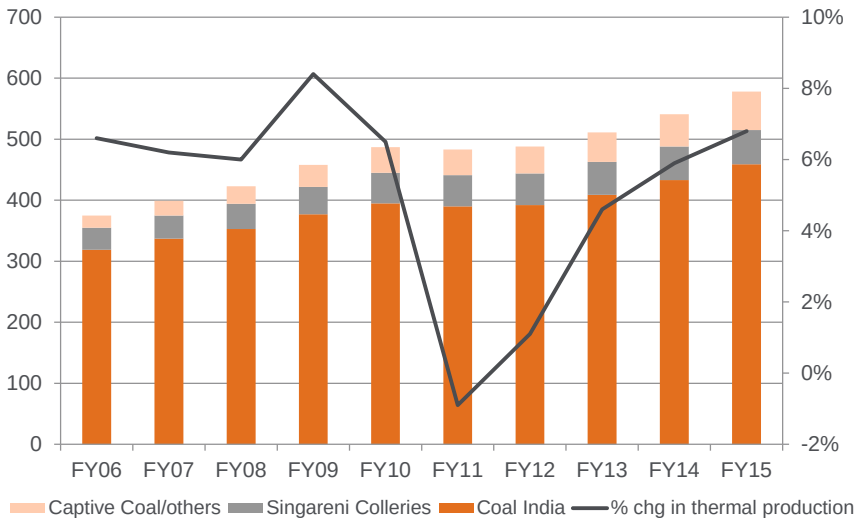
Figure 58. Thermal coal demand/ supply table

(mt)	FY08	FY09	FY10	FY11	FY12	FY13E	FY14E	FY15E
Coal Production	423	458	488	483	488	511	541	578
Change in stock	-3	-5	-16	-7	-2	13	11	6
Domestic despatches	420	453	471	475	484	524	552	583
-% chg	8%	8%	4%	1%	2%	8%	5%	6%
Imports/Shortfall in domestic supply*	28	38	49	49	69	130	189	259
-% chg	10%	37%	28%	2%	39%	89%	46%	37%
Domestic demand	448	491	520	524	553	654	741	842
-% chg	8%	10%	6%	1%	5%	18%	13%	14%
- Shortfall as % of demand	6%	8%	9%	9%	12%	20%	26%	31%

Source: Ministry of Coal, Citi Research estimates. *Data up to FY12 pertains to imports; beyond FY12 signifies the shortfall – adjusted for calorific value the import figure would be lower

Coal India (CIL) accounts for ~80% of India's coal production. Singareni Collieries (jointly owned by the Government of Andhra Pradesh and the Government of India) account for ~10%. Captive coal producers account for the remaining production (195 coal blocks, 43bn tonnes of resources).

Figure 59. Thermal coal production (mt)



Source: Ministry of Coal, Provisional Coal Statistics, Citi Research

Imports – a necessity

With thermal coal demand expected to grow at a CAGR of 15% and supply at a 6.5% CAGR, imports would need to grow at 44%. Our supply/demand analysis suggests Indian thermal coal imports would need to rise from 69mt in FY12 to 207mt (calorific value adjusted) in FY15 (26% of India's demand) and 22% of seaborne trade.

- We think imports are likely to be capped at lower than expected levels due to factors such as 1) SEB losses, 2) internal logistics constraints, 3) a limit to the amount of imported coal that can be blended, and 4) a weak rupee. A more realistic assumption for thermal coal imports is in our view 157mt in FY15 – implying a 32% CAGR (FY12-15) vs. our calculated shortfall of 207mt in FY15. This would imply imports account for 21% of India's thermal coal consumption (~17% currently); ~18% of the sea-borne market (~12% currently).

Figure 60. Thermal coal imports

Thermal coal (mt)	FY11	FY12 (P)	FY13E	FY14E	FY15E
Required Thermal Coal Imports	49	69	104	151	207
Realistic Thermal Coal Imports	49	69	104	121	157
-% of Domestic Consumption	9%	12%	17%	18%	21%

Source: Ministry of Coal, Citi Research

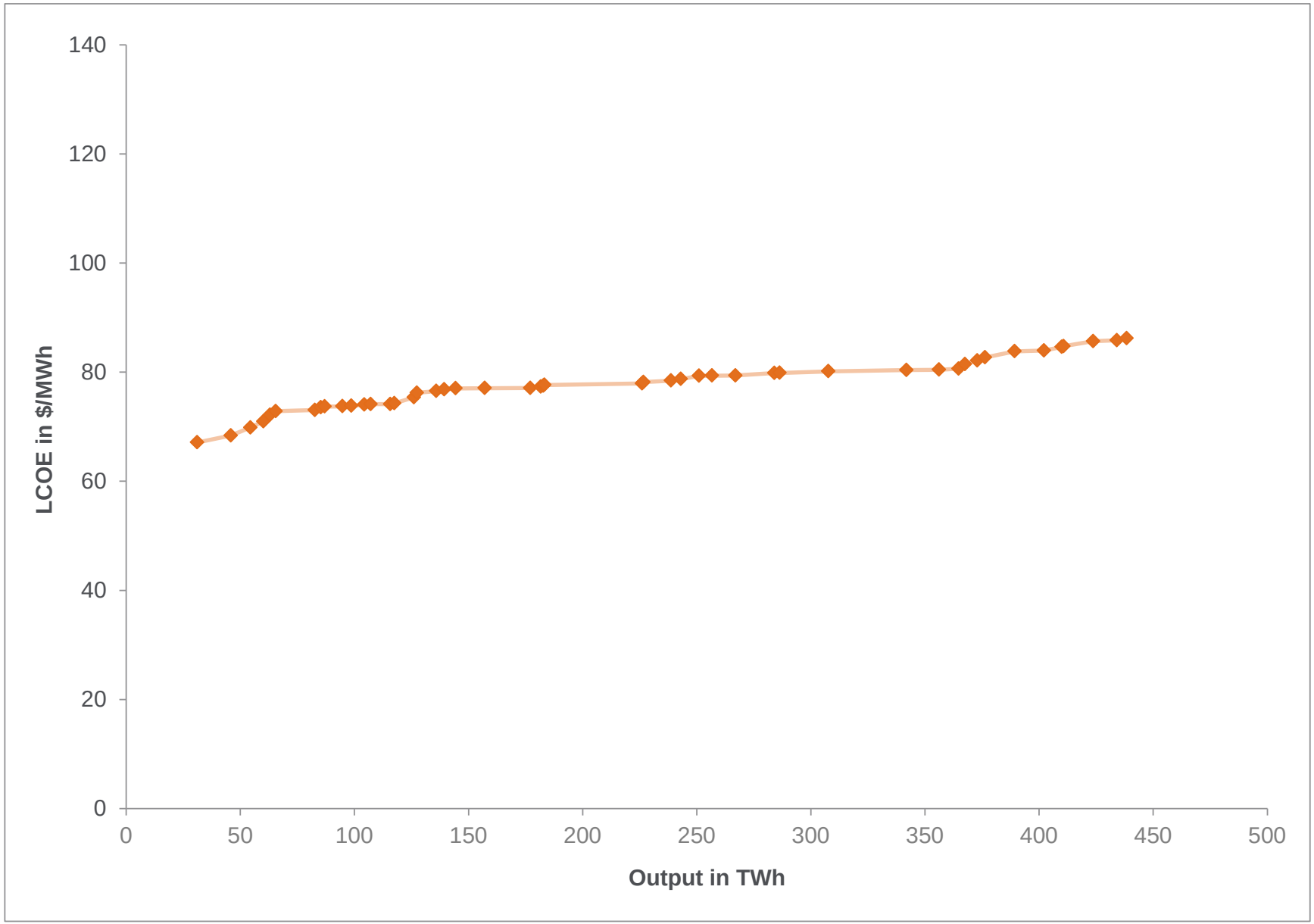
The global coal cost curve

The global coal cost curve

As with the previously calculated gas cost curve, we have generated a global coal cost curve using the expected production of cost from each new (or expanded) coal producing asset coming onstream between now and 2020. Onto this we have made assumptions outlined in the appendices on transportation costs, and converted the cost of coal into an equivalent LCOE thereby allowing it to be compared with the LCOE of competing fuels on our integrated global cost curve.

The global coal cost curve is shown in Figure 61.

Figure 61. LCOE curve for coal-fired generation by upstream coal project – best case



Source: Citi Research

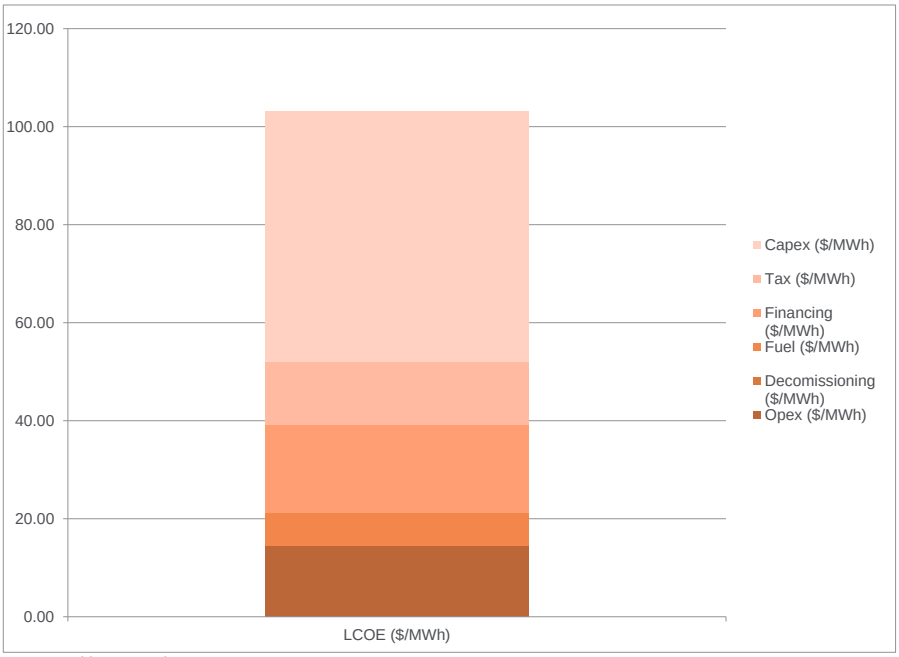
Nuclear: Not suited to competitive uncertainty

Evolution of nuclear is difficult to plot as fuel is a small part of LCOE, and in developed markets costs have risen

While we have included a nuclear 'reference cost' on the integrated LCOE curve, it is difficult to plot a full LCOE 'cost curve' for the technology because fuel is such a small part of the cost equation. Furthermore, the assessment of 'cost' is fraught with 'arbitrary' difficulties such as choice of discount rates, combined with difficulties in assessing cost evolution as costs are actually rising in some parts of the world. Accordingly, nuclear is not included fully on our integrated LCOE curve, though a 'zero-width' indication of a cost range is included for reference purposes.

As Figure 62 shows, fuel costs are just 6% of the cost of a unit of electricity. Accordingly, the price of uranium has little effect on the LCOE, and hence an analysis of different producing assets is of limited use.

Figure 62. Breakdown of LCOE for nuclear power



Source: Citi Research

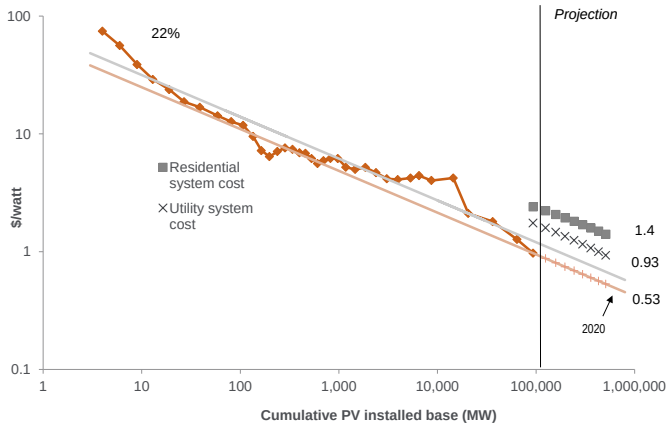
While nuclear technology has evolved over time this is harder to plot, as well as considering the fact that there is scope for a paradigm shift should other methods of nuclear generation such as fusion ever be harnessed/become commercially viable. The capital cost of nuclear build has actually risen in recent decades in some developed markets, partly due to increased safety expenditure, and due to smaller construction programmes (i.e. lower economies of scale). Moreover the 'fixed cost' nature of nuclear generation in combination with its relatively high price (when back end liabilities are taken into account) also places the technology at a significant disadvantage; utilities are reluctant to enter into a very long term (20+ years of operation, and decades of aftercare provisioning) investment with almost no control over costs post commissioning, with the uncertainty and rates of change currently occurring in the energy mix. As an example, one need only look at the ongoing debate in the UK over the next generation of nuclear build, and the reluctance of most parties to commit.

Solar: Technology vs. 'fuel'

Costs have reduced quickly…and are likely to continue to do so

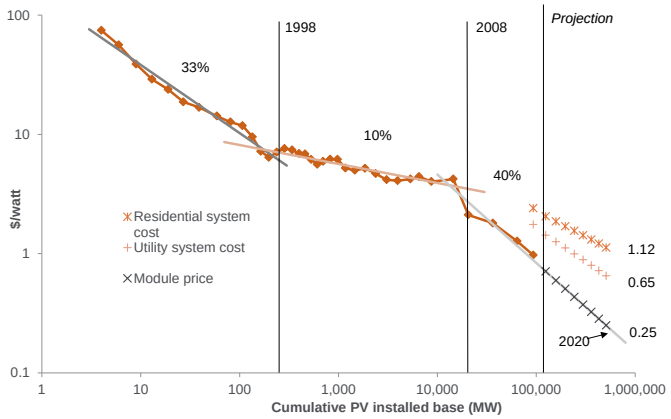
The rate at which the price of solar panels has reduced has exceeded all expectations, resulting in cost parity being achieved in certain areas much more quickly; the key point about the future is that these fast 'learning rates' are likely to continue, meaning that the technology just keeps getting cheaper. At the same time, the alternatives of conventional fossil fuels are likely to gradually become more expensive (assuming that the 'lowest hanging fruit' in terms of reserves are exploited first). In this chapter we examine solar's learning rates and the likely timeline for parity with conventional generation, as well as deriving our solar cost curve.

Figure 63. Solar module price declines from 1972 show an overall learning rate of 22%...



Source: Citi Research, BloombergNew Energy Finance

Figure 64. ...though in recent years that learning rate has increased to 40%



Source: Citi Research, Bloomberg New Energy Finance

As Figure 63 shows, plotting the prices of solar modules back to 1972 shows an overall learning rate of 22%; that is for every doubling of installed capacity, the price of a solar panel has fallen by 22%. However, as Figure 64 shows this learning rate shows three distinct phases, the post 2008 boom showing a faster learning rate of 40%. This faster learning rate is unlikely to be sustainable though, given that many of the factors for this faster learning rate are non-replicable, such as the move of manufacturing to Asia and the squeeze of manufacturing margins to zero and beyond. Conversely, the single speed learning rate of 22% implies panel prices in 2020 at a level which is only marginally below current selling prices, and hence is probably too benign. In reality, we believe the actual learning rate is likely to be somewhere between the two scenarios (22% and 40%), potentially around 30% per annum. Clearly as solar installations increase the 'doubling' of capacity takes longer, as would be evidenced by a flattening of the cost curve were the previous charts not to have utilised a logarithmic scale.

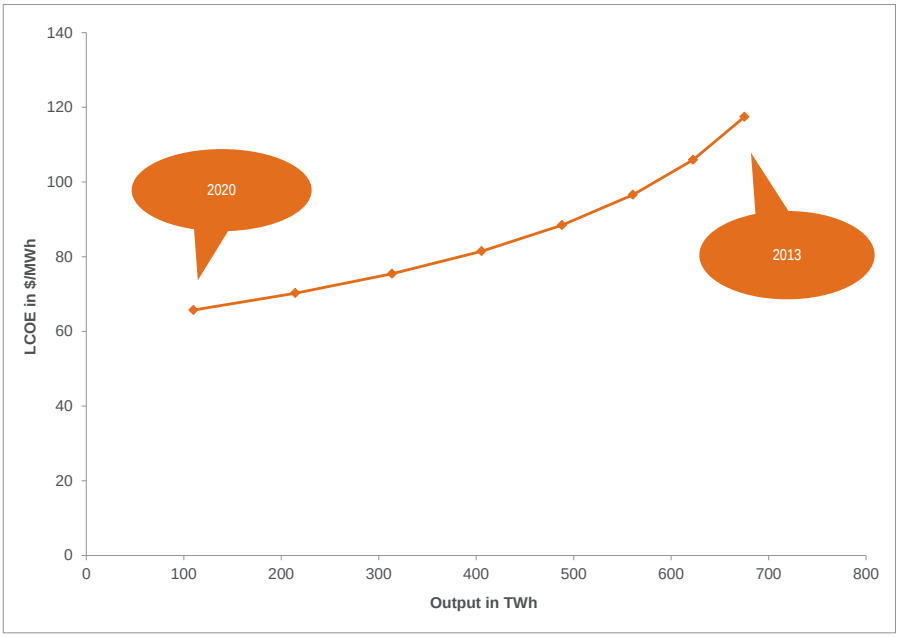
Solar financing is also evolving with the advent of solar leasing and green bonds

It is not just the technology that is evolving in the solar industry; the financing of solar projects, both residential and utility-scale is evolving quickly. The most notable development here has been in the form of solar leasing, whereby the rooftop panels are owned by a third party who effectively leases the rooftop from the home/factory/office owner, the latter receiving payment normally through a reduction in electricity bills paid for by the lessee. This provides the benefits of cheaper and cleaner solar electricity to the homeowner, whilst negating the need for the significant initial capital outlay. The panel owner or lessee earns their return via incentive mechanisms such as the U.S. Investment Tax Credit, and via the sale of the electricity back to the local utility. This financing mechanism has proved particularly successful in the U.S. and is gaining traction in the UK, with companies in other countries looking to follow suit.

At the utility scale level, the emergence of innovative financing vehicles such as green bonds is also facilitating deployment of the technology. The predictable and low-risk nature of solar generation means that it is ideally suited to debt finance. Green bonds are essentially a pooled investment which is then invested in the debt of many different projects, potentially in different countries or jurisdictions, thereby reducing technology, political, regulatory and other risks via the portfolio effect. The long-dated nature of solar farms with their (relatively, depending on location) predictable revenue streams, low risk (no moving parts, maintenance) and attractive returns relative to bond yields make them especially attractive to certain types of investor such as pension funds or insurance companies, as well as companies looking to boost their green credentials while earning an attractive return on capital.

Plotting the technological learning rates discussed earlier onto the cost of solar in different years produces the solar cost curve shown in Figure 65 which will later be combined with those for other generation technologies.

Figure 65. Solar LCOE cost curve showing cost reductions over time – best case



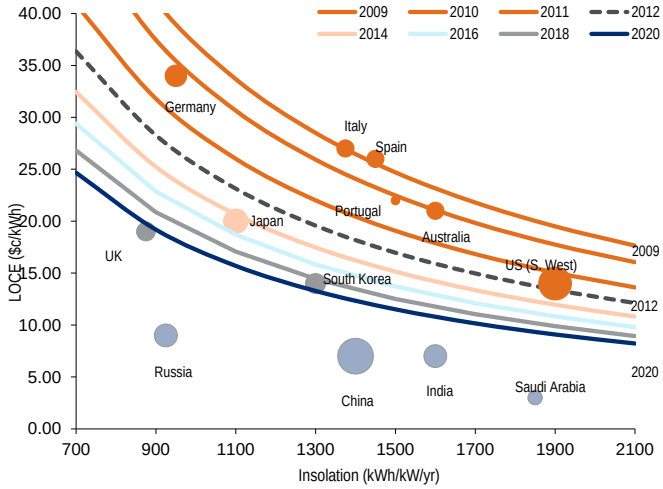
Source: Citi Research

The relative economics of generation

Already cost competitive in an increasing number of regions

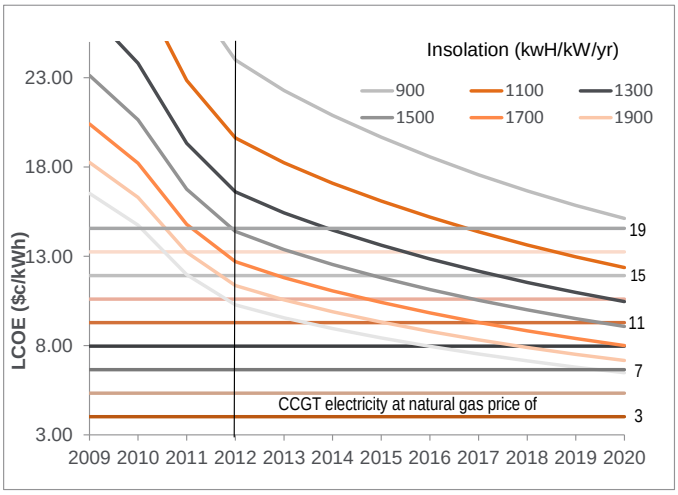
These dramatic cost reductions mean that solar is already competitive in many regions at a domestic level (Figure 66), and even at utility scale vs. combined cycle gas turbines (CCGT's) in some higher priced markets (Figure 67). As discussed, the fact that solar keeps getting cheaper as technology advances and manufacturing becomes more efficient means that 'parity' will be achieved in an increasing number of markets in a relatively short timeframe. We would also note that Figure 66 and Figure 67 are calculated using the lower 22% overall learning rate; clearly if we were to use the 40% more recent learning rate (or even the mid-range 30%), then parity would arrive more quickly in broader range of markets.

Figure 66. Domestic 'socket' parity has already been reached in German, Italy, Spain, Portugal, Australia and the SW states in the U.S/



Source: Citi Research

Figure 67. Utility scale solar is already at parity with CCGT's in higher priced gas, sunny markets



Source: Citi Research
Note: Curves show cost of solar, dotted lines cost of CCVGT electricity burning gas at the price show in RHS))

Wind: Old as the mills but still evolving

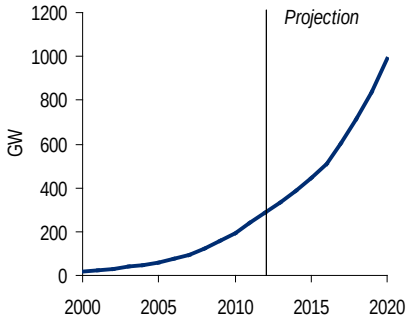
While wind technology is evolving, it is doing so much more slowly than solar. However, it has the advantages of offering more 'base-load'-like characteristics in running more of the time, and perhaps most importantly is lower cost than solar, allowing the technology to compete against conventional generation at lower wholesale prices. In this chapter we examine its evolutionary rate, its cost competitiveness and finally derive our wind cost curve.

Wind turbine costs can be forecast by propelling forward the 'experience curve'…

Wind turbine costs represent ~70% of total wind system costs. We forecast future wind turbine costs by projecting our estimates for future wind capacity production onto a similar historically observed 'experience curve' for the costs, which assumes that turbine costs decline by a constant percentage for every doubling of production.

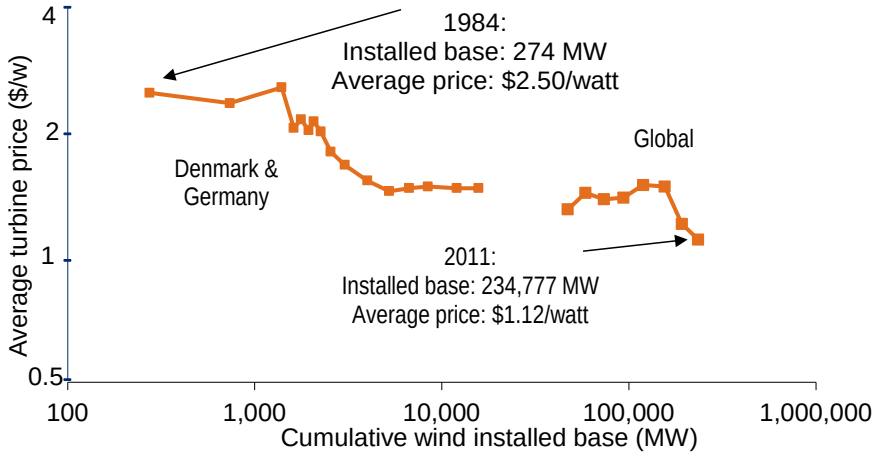
This decline is borne out by the price data, which pre-1999 covers Danish and German manufacturers and post-2004 covers global manufacturers (Figure 69).

Figure 68. Forecast for future cumulative wind installed base



Source: Citi Research

Figure 69. Historical average turbine costs against cumulative installed capacity

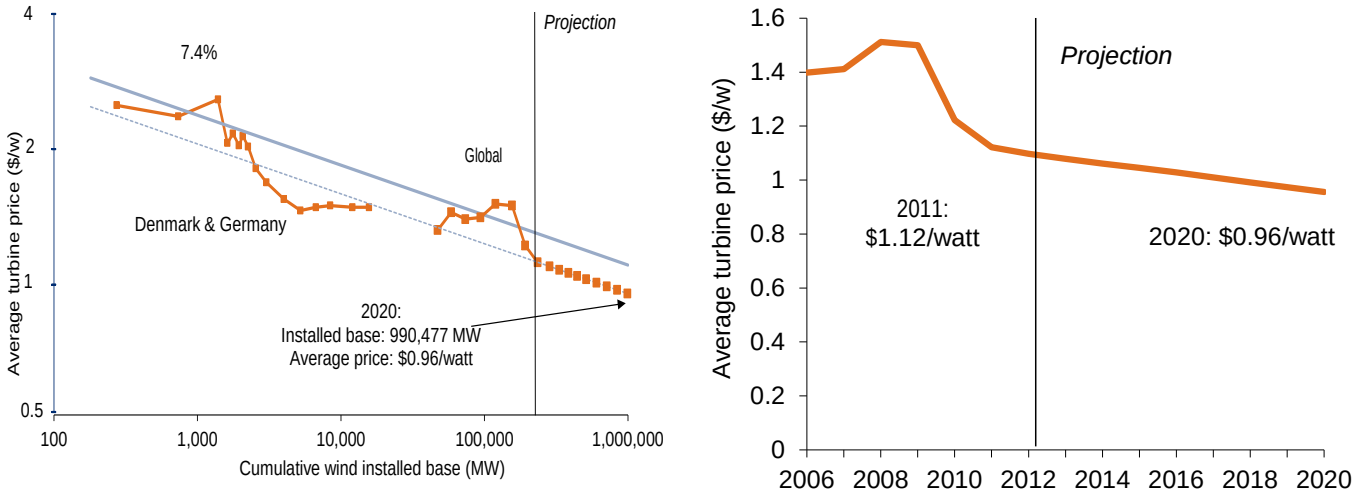


Source: Bloomberg New Energy Finance, Citi Research

…using a 'learning rate' of 7.45

On this data, wind turbine costs are driven by a 'learning rate' of 7.4% (Figure 70). To project future prices, we apply this rate to the current turbine price. On this analysis, we expect average wind turbine costs to be at $96c/watt by 2020.

Figure 70. Forecast for average wind turbine costs



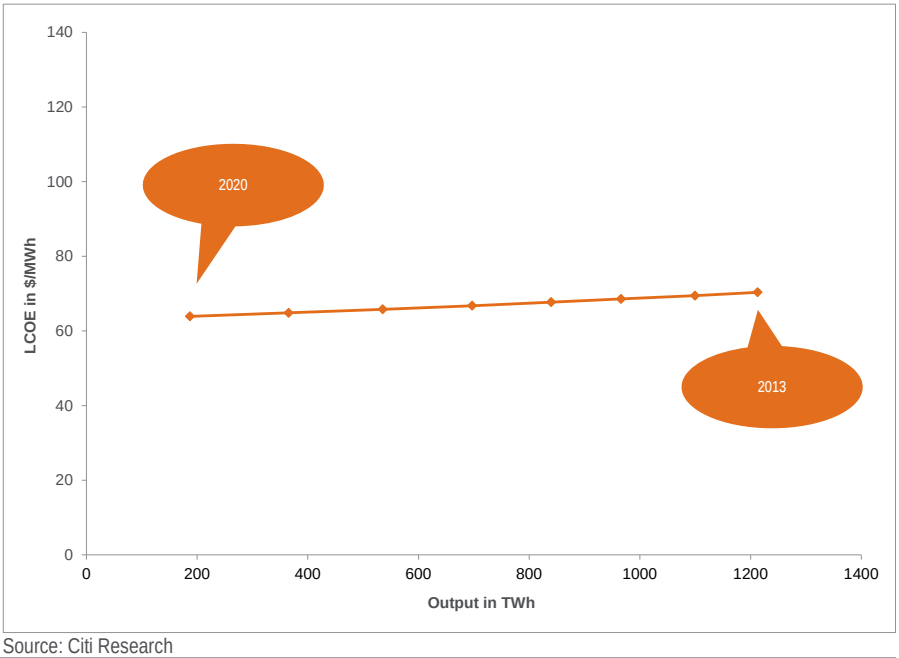
Source: Bloomberg New Energy Finance, Citi Research

Wind exhibits significantly slower learning rates than solar

It is interesting to note the significantly lower learning rates exhibited by wind vs. solar. We put this down to the fact that a wind turbine is a mechanical item made up of many thousands of individual components, and hence improvements are via a more physical piecemeal process vs. the technology and lab-based nature of solar advances.

Plotting these learning rates onto the cost of wind in different years produces the wind cost curve shown in Figure 71 which will later be combined with those for other generation technologies.

Figure 71. LCOE curve for wind generation showing cost improvements over time – best case



Source: Citi Research

Utility-scale wind is already competitive with gas-fired power

Wind can already compete with gas and coal in the right markets and conditions

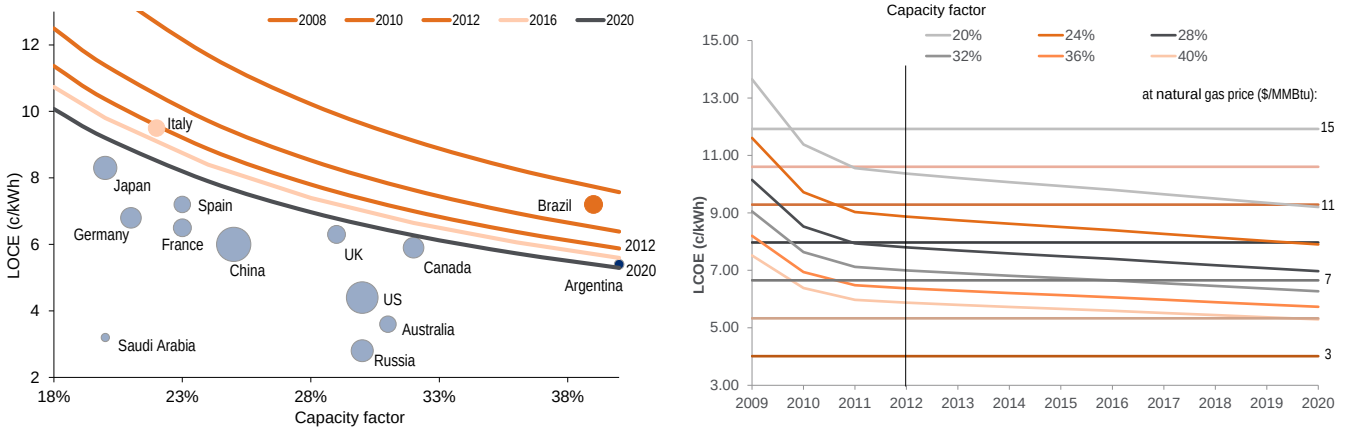
Wind power is significantly cheaper than solar power, and in most countries wind delivers electricity at a far lower cost than the residential electricity price. However, even at the more relevant utility scale, wind power is already competitive with gas-fired power in many regions. In the best U.S. sites, for example, wind power would be cheaper than gas-fired power at a natural gas price of ~$6/MMBtu.

Wind power LCOE is approaching the average wholesale electricity price in a number of large markets – including Italy, Spain, the UK and China – and has already attained and surpassed parity in Brazil.

Wind power is also already competitive with gas-fired power for a broad range of capacity factors and natural gas prices (Figure 73). At a capacity factor of 21% – achieved in Germany – wind power is currently competitive with gas-fired power for natural gas prices under $10/MMBtu. At a capacity factor of 24% – achievable in some regions of Southern Europe – wind power is currently cheaper than gas-fired power at gas price of under ~$9/MMBtu. At a capacity factor of 30% – attainable in the UK, U.S. and Australia – wind power is cheaper than gas-fired power for natural gas prices of under ~$7/MMBtu.

We expect the competiveness of wind power to increase further due to cost reductions and increases in efficiency. Our analysis is that, by 2020, wind power will be competitive with gas-fired power at a natural gas price of roughly ~$1/MMBtu less than today. For the U.S., for example, this means that wind power will be competitive with gas-fired power for a natural gas price of under $6/MMBtu.

Figure 72. Utility-scale wind LCOE compared to wholesale electricity prices and gas-fired LCOE for various natural gas prices



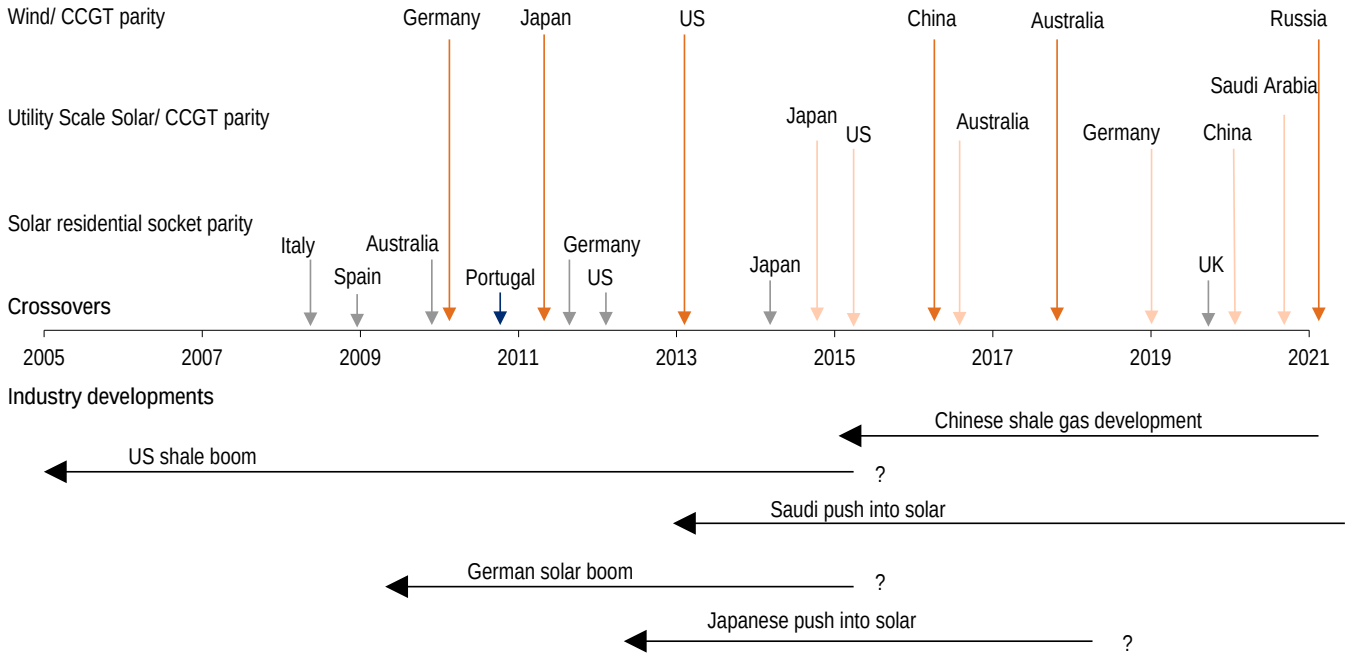
Source: Citi Research

The parity timeline

Parity for renewables is already a reality in some market, and will become more widespread in a short timeframe

There are an enormous number of variables in calculating socket and grid parity in differing markets, not least what happens to fossil commodity prices which can vary dramatically between regions. However, Figure 73 shows our estimate of a parity timeline, showing residential 'socket parity' already having been achieved in many markets, with utility scale solar achieving parity vs. CCGT's potentially from the middle of this decade and wind already there in some markets. These issues are examined in much greater detail in our recent report: Shale & renewables: a symbiotic relationship - A longer-term global energy investment strategy driven by changes to the energy mix

Figure 73. The parity timeline, showing cost competitiveness of residential and utility scale solar in various countries, with reference to wind generation and the development of shale resources.



Source: Citi Research

Transporting energy units

The advent of shale gas and the corresponding rise in LNG projects is transforming the transportability of energy, with knock-on effects on pricing differentials of certain commodities between different markets. In this chapter we examine the transportability of energy, the impact of the costs on pricing, how they are changing, and how they should be considered when using our integrated global cost curve.

The provision of power to end consumers involves five broad steps: the energy source, some form of transport to the power generation facility, followed by transport in the form of a grid to the final consumer. For example coal is mined then transported via a train, truck, ship, or conveyor, or combination of all these to the power station where it is converted into electricity and then transported via a grid to the consumer.

Figure 74. The stages of energy transportation

Source: Citi Research

Energy transportation is vital to the process of energy substitution and arbitrage

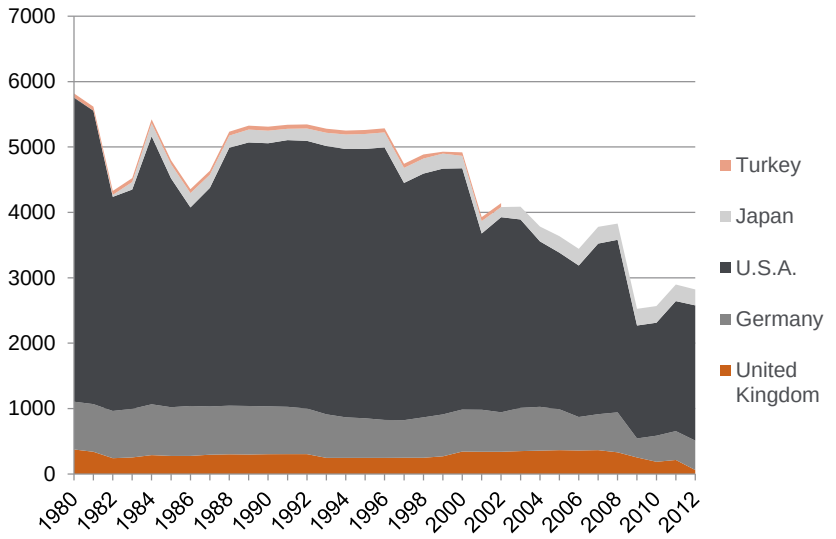
The ability to transport energy has a large bearing on the ability to arbitrage different energy sources, and in turn impacts the costs and efficiencies achievable. Infrastructure is a key determinant in this process be it a pipeline, LNG facility or port into the power generation location, alongside how developed the local grid is in transporting the energy to the final consumer.

Some commodities such as aluminium allow energy transportation by proxy

Historically commodities such as aluminium have also been used to arbitrage energy differentials, effectively providing energy transportation by proxy. Aluminium could be viewed as solid energy, with one tonne of aluminium requiring ~14,000 Kwh to produce; in comparison, an average western family consumes around 3,300kwhr a year. In 1980 Germany was producing around 6m tonnes of aluminium, equivalent to the current energy usage of around 32million people per annum today. Accordingly by using local cheap energy (which could not otherwise be transported) to produce aluminium at a lower cost than elsewhere, those lower power prices can effectively be 'sold' overseas in the form of cheap aluminium, even if the infrastructure to move the energy or power in its raw form did not exist.

The industrial developments in Europe, the U.S. and Japan all involved aluminium smelters being built around power generation acting as initial baseload demand. Once the transportation grid and the economy grew, the aluminium smelters were shut and power was sold at a higher price to an end use consumer.

Figure 75. Developed world aluminium production ('000t)

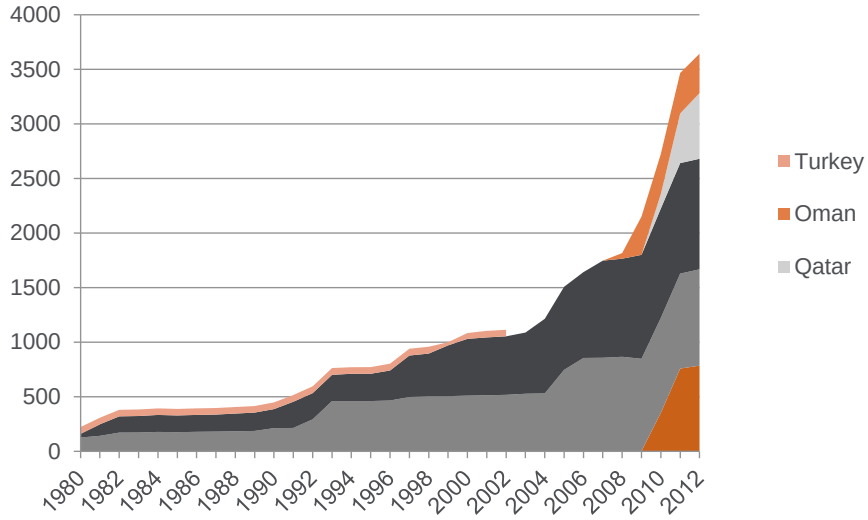


Source: Citi Research

Commodities and now transport allow the monetisation of stranded energy sources

The energy arbitrage in aluminium has also occurred where there has been stranded energy sources such as the Middle East, where gas has been exploited by building a power station coupled with an aluminium smelter, as highlighted in Figure 76.

Figure 76. Aluminium production in the Middle East



Source: Citi Research

LNG has increased the transport and arbitrage potential for gas

However, the surge of natural gas production and in particular the rise of LNG has resulted in gas rich countries being able to exploit pricing differentials without building an aluminium smelter.

Other developments in the energy industry have also served to change the transportation chain; solar has effectively condensed the chain between the energy source (e.g. on the roof of the house) to where it is consumed (in the house). This gives the technology a cost advantage in that residential solar competes with socket electricity prices (which include transmission and distribution costs) rather than much lower wholesale prices (i.e. at the exit of the power station).

Cost of liquefaction and transportation

The LNG process is an expensive one…

The costs of liquefying, transporting and regasifying gas as LNG are all expensive and are expected to stay so because of the energy-intensity of each process. This has meant that significant regional pricing divergences have persisted, as highlighted by the differential between the U.S., Europe and Asia in recent years.

…which combined with transport costs allows regional pricing differentials to remain

The friction in the market which allows these differentials comes from the transport costs. To illustrate, transporting a ton of coal from a mine in the U.S. (e.g. Central Appalachia) to China's Qinhuangdao port costs about $60/ton at present, or $2.67/MMBtu; the cost of transporting a ton of oil is negligible; but a ton of LNG should cost between $5 to 6/MMBtu to ship, including liquefaction, boil-off losses and regasification.

So why is the cost of "transporting" gas so expensive? The U.S. Sabine Pass LNG export terminal, currently under construction, serves as a good example. Although US natural gas might cost $4 to $6/MMBtu by the time the U.S. begins exporting gas in 2015, the delivered cost of the same gas to Asia could be between $10 to $12/MMBtu, as shown in Figure 77.

Figure 77. Potential delivered prices of US gas to Japan and Europe, showing the impact of transportation and related costs

Japan		Henry Hub Prices ($/MMBtu)		
Unit cost ($/MMBtu)		4.00	5.00	6.00
Fee (Variable)	115%	4.60	5.75	6.90
Fee (Fixed)	3.00	7.60	8.75	9.90
Shipping (Panama)	1.70	9.30	10.45	11.60
Regas	0.40	9.70	10.85	12.00

Europe		Henry Hub Prices ($/MMBtu)		
Unit cost ($/MMBtu)		4.00	5.00	6.00
Fee (Variable)	115%	4.60	5.75	6.90
Fee (Fixed)	3.00	7.60	8.75	9.90
Shipping (Panama)	0.75	8.35	9.50	10.65
Regas	0.40	8.75	9.90	11.05

Source: Citi Research

Liquefaction is itself an energy intensive process…

Part of the cost comes from the extra energy needed to liquefy the gas, which could take as much as 15% of the total gas volume. Hence, if the gas cost is $4/MMBtu, then an extra $0.6/MMBtu would be added because of fuel cost. This percentage could change due to efficiency of a liquefaction plant. Plants located in very hot climate tend to have lower efficiencies while plants in more temperate climate have higher efficiencies.

Liquefaction plants are also expensive to construct because of the various components needed, including pipelines to take gas to the liquefaction facility, the liquefaction plant itself, specialised storage tanks to keep the gas in liquid form and the loading terminal. Sabine Pass is a brownfield facility and it only charges capacity holders $3/MMBtu for the use of the liquefaction facility, as the capital cost of phase 1 of the project was only ~$5 billion. This is near the low end of the cost range for new liquefaction facilities, as the Sabine Pass terminal is originally a regasification terminal. Much of the site preparation, pipelines, storage tanks and dredging have already been done. The largest cost component for this terminal is the liquefaction plant.

…with high capital costs…

In contrast, greenfield facilities would have to build all of these components from the ground up. The high capital cost translates into higher "capacity charges." Some Australian projects cost more than $50-billion to construct. Challenging upstream exploration and production conditions also add to the total cost that includes the construction of other components which make up a liquefaction facility.

…and proportionately high transport costs

Another cost component is the actual transport of LNG cargoes from liquefaction facility to regasification facility, which includes the rental cost of an LNG tanker and the fuel used. In the Sabine Pass example, it takes ~$1.7/MMBtu to ship LNG from the U.S. Gulf Coast to Japan. With the surge in LNG production starting in the middle of this decade, the number of tankers on order has risen, leading to falling "dayrates," or the daily rental cost of a tanker. However, note that tanker rates are only a subset of the total cost that so far is being dominated by the capacity charge of the liquefaction terminal. Hence, a collapse in tanker dayrates, if it happens at all, may only take the total "transport" cost down by a relatively small amount. The fuel cost is essentially the price of the prevailing LNG price, as the boiled-off gas used as fuel would not be sold as delivered LNG. Some tankers still use fuels other than LNG as their energy source.

Finally, the cost of regasification once a LNG tanker reaches shore and unloads could be in the range of ~$0.5/MMBtu. This essentially is the capacity charge of using the regasification facility. The cost of building a regasification plant is much lower, some costing in the low-hundreds of millions USD.

LNG becomes cheaper than gas pipelines for distances >2000km

Despite the high costs of LNG transport relative to coal and oil, LNG is still competitive vs. pipelines beyond a certain distance. The general rule of thumb is that for distances shorter than 2000-km, then gas transport via pipelines is more competitive vs. LNG. In addition to the cost of pipes, compressor stations have to be scattered along the pipe to "push" the gas forward. This also requires additional cost for fuel.

Summary

The competitive advantage enjoyed by energy-rich nations is exacerbated by transport costs

This examination of transport costs highlights the advantage of countries that have direct access to inexpensive domestic gas production. This explains the energy cost advantage enjoyed by companies in the U.S. and in Middle Eastern gas producing countries, for example. In particular, petrochemical plants, which use both natural gas and natural gas liquids (e.g. ethane, propane and etc.) as fuel sources and feedstock, have been expanding in the Middle East and are migrating back to North America. Refineries are also increasingly using natural gas as a fuel source and agent to make hydrogen.

Perhaps most importantly though is to consider the impact of transportation costs on the Citi global integrated cost curve which we derive in the next chapter.

While we do not explicitly include transportation costs on the LCOE curve, their impact should be considered

The curve is derived from the costs and volume of output from each primary energy 'asset', be it a particular gas field or coal mine coming on stream between now and 2020. Clearly that commodity could go anywhere in the world, depending on price and demand. Accordingly adding transport costs is extremely difficult, given that we do now know where each asset will ultimately be used (or indeed whether it will be used for power generation, heat, or transportation).

Accordingly it is not possible to adjust the curve for transportation costs, and hence these are not included in our calculation of LCOE. However, when looking at the curve in more detail (for example at the position on the curve and relative competitiveness of a specific asset) it will be important to consider who, what and where that commodity or the energy that it produces will ultimately be sold to; this will be the final element in the assessment of the viability of projects, and the calculation of their likely lifetime returns.

Global energy competitiveness

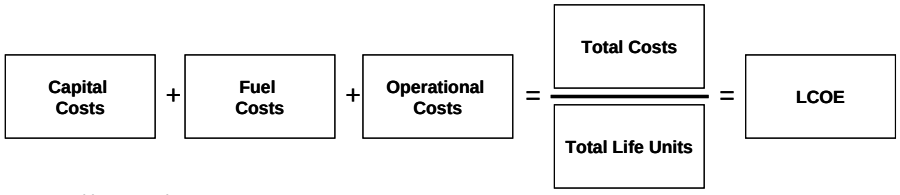
So, innovation and technology are changing the competitive landscape of the global energy markets. The consensus view is that coal and to a lesser extent nuclear will remain the backbones of energy usage for the coming decade, however this is being tested by the innovation-led shale gas boom and technology changes in renewables. The question of which energy source will be used is likely to be a function of the relative cost advantages of each fuel source, the associated risks of each energy source, combined with other more subjective drivers such as a desire for increased energy independence. In this chapter, we combine the previously derived cost curves to create our integrated global energy cost curve which allows us to compare the cost of energy derived from different fuel sources, right down to individual gas fields or coal mines, and hence assess the competitiveness of those assets, their potential returns and the associated risks.

Our view is that coal is likely to experience a negative structural shift, gradually losing its competitive advantage as a fuel source. Gas-fired power is likely to be the main beneficiary; while utility-scale renewables will be completive with gas-fired power in the short and medium term, gas with its flexibility and attractive economics is likely to be needed to offset the intermittency of renewables. The exact crossover is largely country-dependent. The risks associated with nuclear are likely to preclude investments without solid state assurances of prices to be received, and/or state backing.

Assessing competitiveness

To assess competiveness of energy sources we have used the 'Levelised Cost Of Electricity' (LCOE) as the comparator. The LCOE quantifies the average cost of producing a unit of electricity from different sources of power.

Figure 78. Levelised Cost of Electricity (LCOE)



Source: Citi Research

How is LCOE calculated?

The LCOE is a measurement of the average cost of producing a unit of electricity over the lifetime of the generating source — in this case a coal-fired power plant, a gas-fired power plant or a solar/ wind installation.

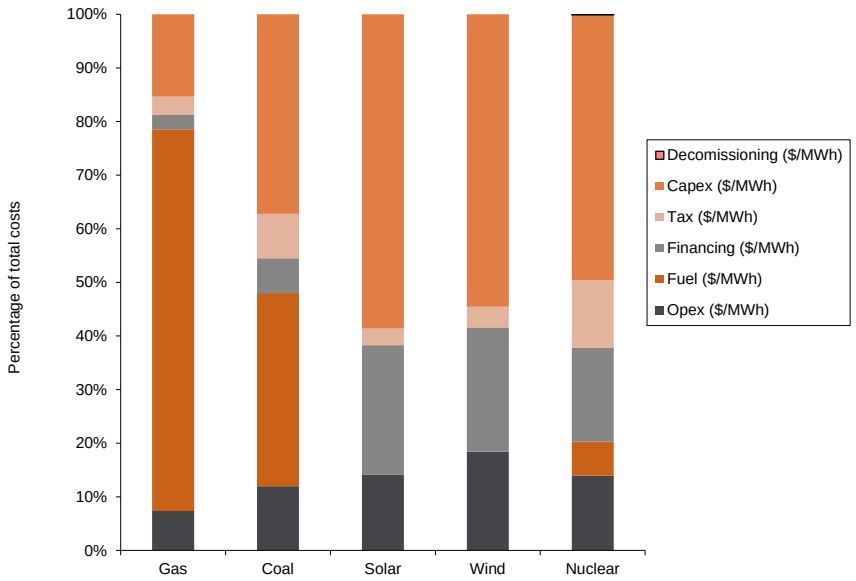
The LCOE considers, on the one hand, the total quantity of electricity produced by the source, and on the other, the costs that went into establishing the source over its lifetime, including the original capital expenditure, ongoing maintenance costs, the cost of fuel, transport and any carbon costs.

The LCOE also takes into account financing costs of the project, both deducting the cost of debt (For an appropriate level of debt-financing) and ensuring that the project generates a reasonable internal rate of return (RR) for the equity providers.

LCOE breakdown varies significantly by generation type

The LCOE varies significantly between fuel sources, depending on the capex required, financing, and fuel source along with operational costs. Figure 80 breaks down the relative components as a % of the overall LCOE cost.

Figure 79. LCOE breakdown by cost component



Source: Citi Research

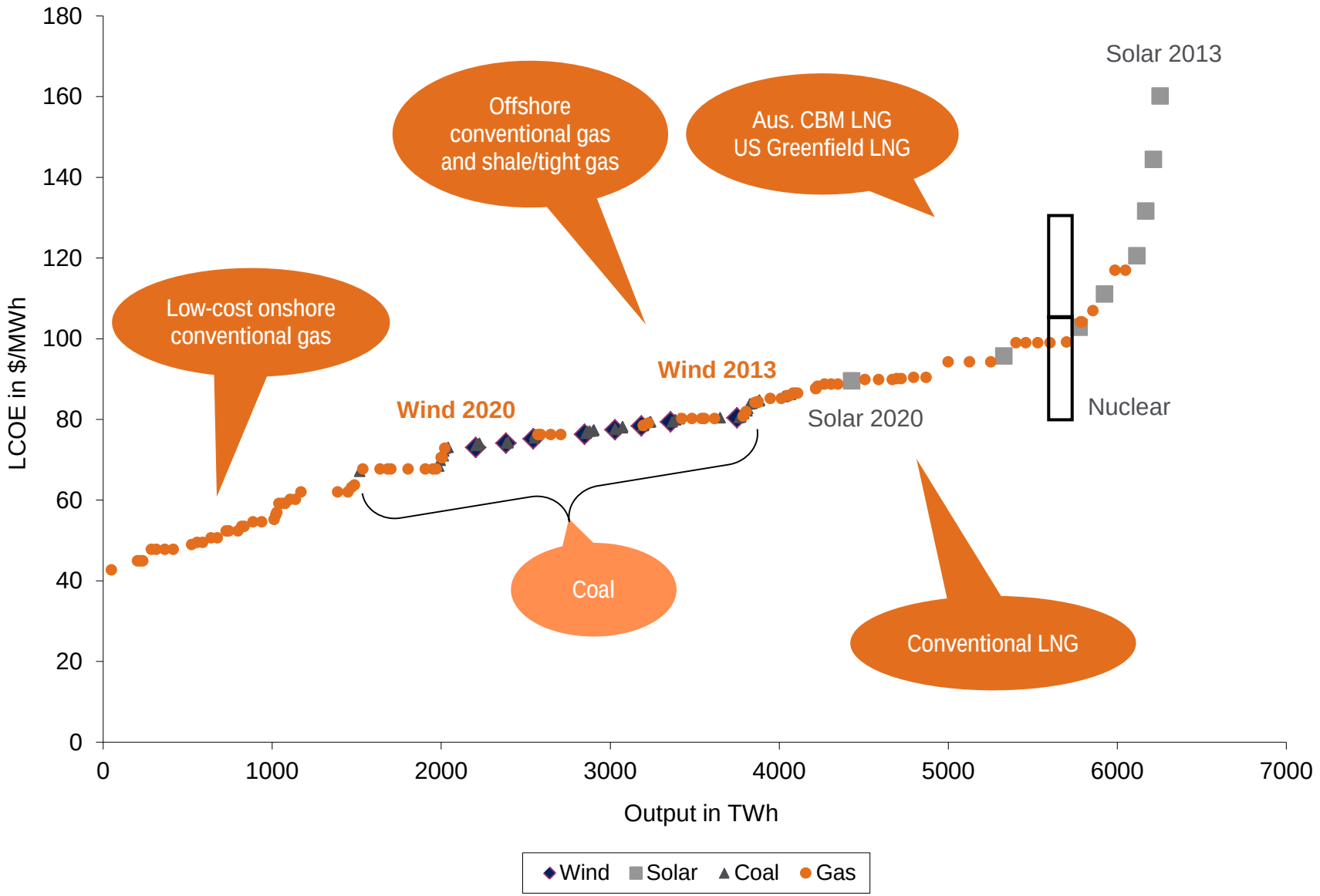
The integrated LCOE cost curve

Having derived the respective LCOE curves for the individual fuels and technologies in the preceding sections, combining them into the Citi integrated energy cost curve provides the focus of this report.

The Citi integrated energy cost curve allows examination of the risk to specific upstream investment in a more holistic manner than we believe has been attempted before

Citi has undertaken a detailed analysis of all incremental future projects and across fuel sources; the curve takes into account all potential new coal mines (or extensions) and new gas fields along with solar and wind cost evolutions by year with estimated volume of build-out. A detailed list and projects considered is given in the appendix for each commodity. We have then run each project, by fuel source, through the corresponding LCOE model and plotted the outcome on a single integrated LCOE curve.

Figure 80. LCOE curve for energy importers – base case to 2020



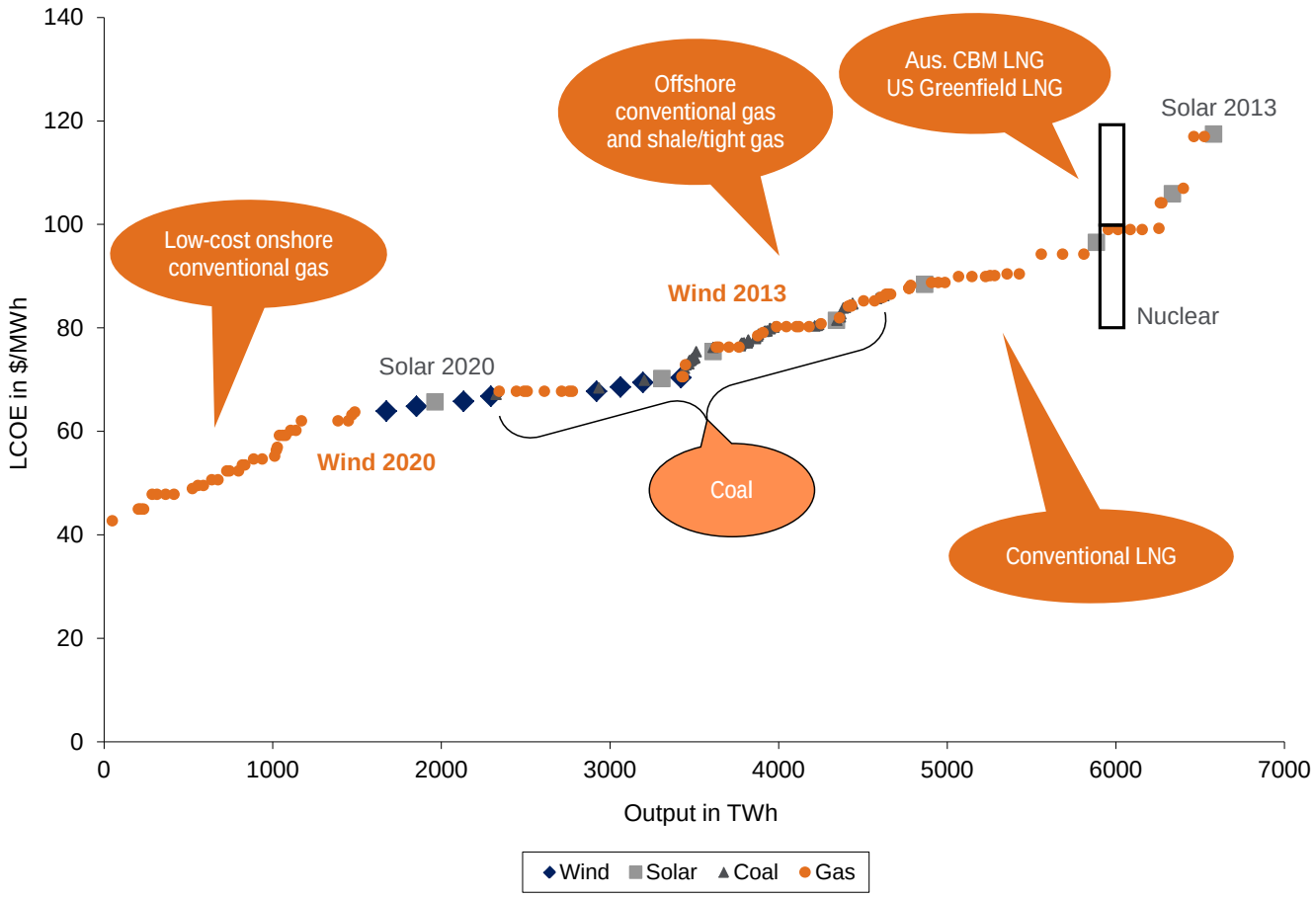
Source: Citi Research

A more optimistic case for solar and wind sees them start to push coal further up the cost curve

The curve in Figure 80 assumes current capacity factors for wind and solar, though we also model a more optimistic capacity factor where we increased the wind capacity factor from 28% to 32% (for comparison the best U.S. sites currently have 40% capacity factors). For solar we increased capacity factors from 12.5% (1,100 sunshine hours per annum) currently to 17% (1500 sunshine hours per annum); for comparisons the UK solar is currently 10.8%, Japan 12.5%, China 13-17% and Saudi Arabia 22%.

As can be seen under this scenario in Figure 81, gas would continue to dominate the bottom quartile while wind and solar would largely displace coal in the second quartile.

Figure 81. LCOE curve for energy importers – best case to 2020



Source: Citi Research

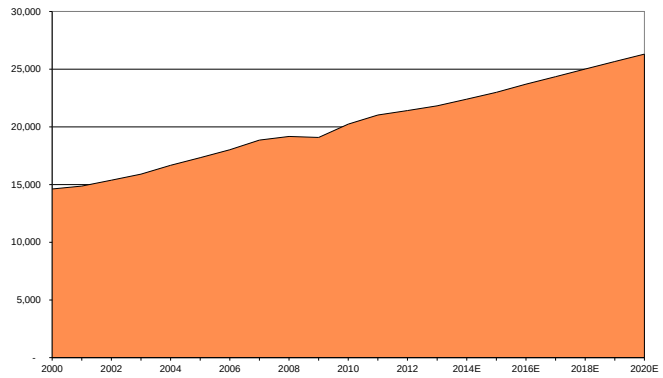
Power generation demand impacts the cost curve at the top of the second quartile

In terms of global generation demand, Citi forecasts globally an incremental demand growth of 3,903TWh between now and 2020 at an average growth of 2.6% globally, which is broadly in line with other agencies such as the EIA and IEA. If we plot the expected incremental global power demand it would intercept the end of the second quartile on the cost curve (Figure 83). We are quick to point out that this analysis has been aimed at the energy importers level which is more akin to the globally traded or seaborne market and therefore excludes domestic or closed loop systems; as such for an actual standpoint the intercept is likely to significantly shift to the left of this curve.

Only around 40% of gas is used for power generation

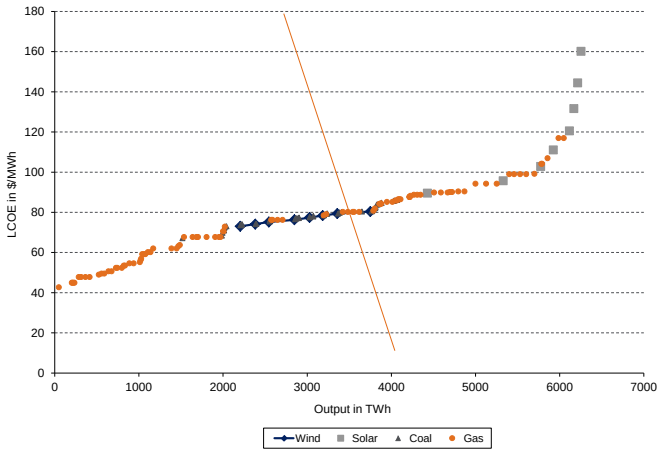
We would also note that in this analysis we have included all gas fields projected to come onstream pre-2020. Currently only about 40% of gas is used for electricity generation, the remainder being used for heat, industry and to a lesser (but increasing) extent transportation. However, this does not negate the analysis; gas for heat and energy purposes could withstand higher upstream pricing due to the lack of conversion costs and losses, and moreover utility purchasers are likely to be amongst the most sophisticated, and hence assuming that the best assets are used for electricity generation provides an interesting picture (clearly if this is not the case, the cost curve moves up and to the right, meaning that other fuels in particular become more attractive in relative terms).

Figure 82. World generation capacity (TWh)



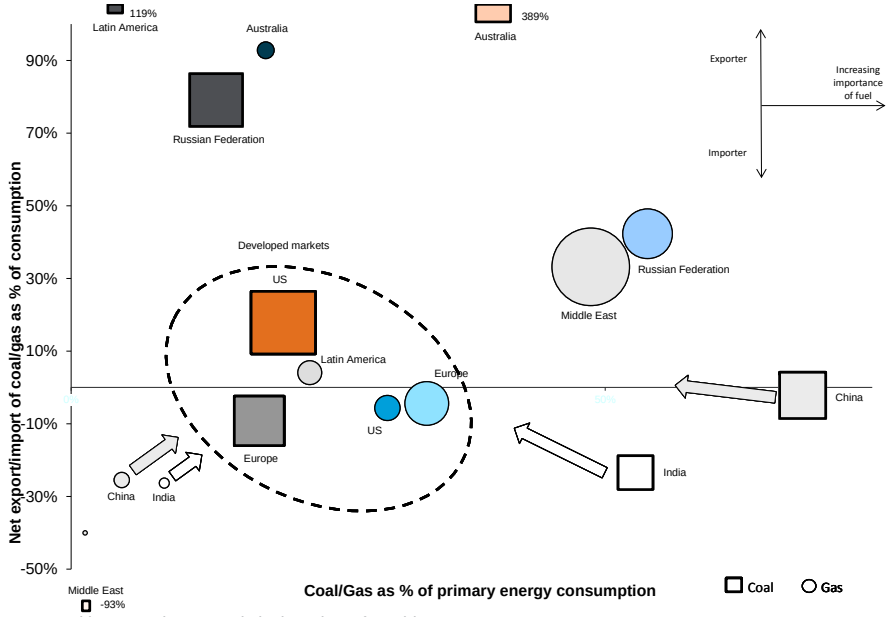
Source: EIA, Citi Research

Figure 83. LCOE intercept curve for energy importers – best case



Source: Citi Research

Figure 84. Converging energy usage



Source: Citi Research, BP Statistical Review of World Energy

Figure 84 is designed to show the potential future impact of the integrated cost curve on different nations depending on their energy mix and their status as importers/exporters. It is apparent that most developed markets have clustered around a more balanced energy mix (as they transition further). The US gas 'circle' will continue to move higher as it moves from importer to exporter, and coal exports are also likely to increase. However, developing markets show two key characteristics: 1) their typical focus on one key fuel, and their nature as energy importers (e.g. coal in India and China). However, over time we would expect these countries to move to more balanced energy mixes as they also transition, and moreover that their level of imports will reduce, most notably in the case of coal in China. These transitions will clearly have implications for the exporters of commodities positioned higher up on the chart.

Fuel cost provides one of the largest risks to utility operators

Arguably, the largest risk components for utility operators are security of supply and the volatility of input prices, once the capital has been committed. In Figure 84 we plot the cash flow for the life of a new power plant at a various input costs. We have excluded solar and wind from this analysis, given their lack of fuel use.

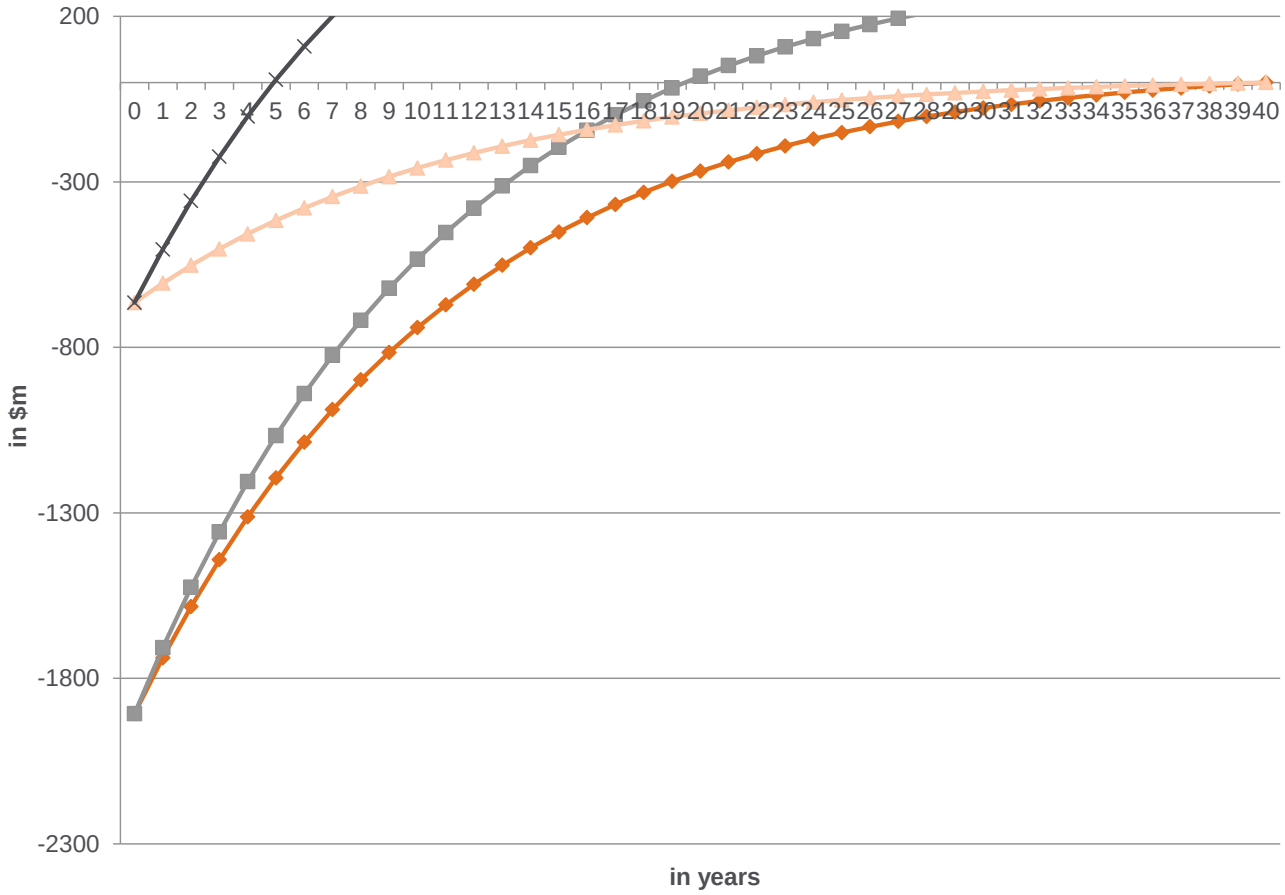
We have taken the upper quartile projected costs for 2020 for gas and coal and then fixed the power price needed to result in a break even after 40 years. We have then dropped the fuel input costs to the lowest quartile for each fuel source by 2020. On a delivered basis for coal the two scenarios are $95/t real delivered price (assuming ~$15/t transport costs) and at the lower end $60/t delivered. For gas, we have assumed $10/MMBtu delivered (including assumed transport costs of $3/MMBtu) at the bottom end of the curve $6/MMBtu delivered.

Power station payback periods can vary by a factor of 2 to 6 times between first and fourth quartile fuel costs/LCOE competitiveness

The payback differentials between the two fuels sources are stark, arguably on a best case scenario for coal the payback period would drop from 40 years to around 20 years. In contrast for gas the payback period would drop from 40 years to around 6 years, thereby demonstrating the extreme sensitivities for project returns from fuel input costs.

This perhaps highlights best the purpose of this report in producing an integrated energy curve. The energy mix is transitioning faster than anyone expected 5 years ago, and price positions on the curve, be it for shale gas, wind or solar are very different to what might have been expected. Moreover, these positions are likely to continue to evolve, with an impact on the relative economics of generation using those fuels (with demand having a feedback loop influence on pricing).

Figure 85. Coal and gas breakeven – cashflow in years

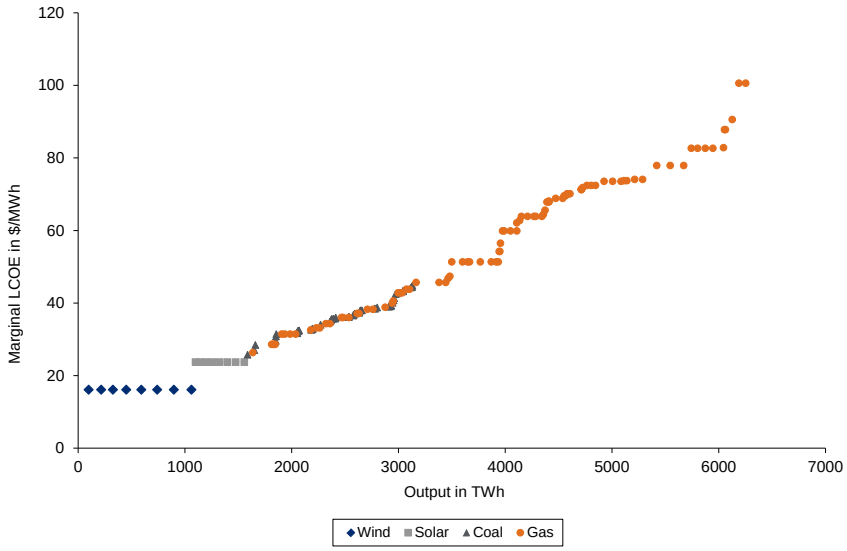


Source: Citi Research

Coal and renewables unsurprisingly beat gas for existing capacity, given lower fuel costs

Another way to use the LCOE model is to exclude the capital cost component and therefore assess the competitive position of currently installed capacity. The following chart excludes capital costs and assesses solely on fuel source costs. Unsurprisingly solar and wind dominate the bottom quartile but what is interesting is coal displaces most of the gas projects. In essence, we believe this explains the existing consensus view that coal, for the most part, is a more competitive fuel source than gas and partly explains why for example in Europe electricity generators continue to operate coal fired power stations at or close to maximum capacity. Nevertheless, this excludes a growth component and our analysis suggests that particularly energy importing regions are unlikely to build new coal fired power stations. Moreover, coal demand could fall as coal fired power stations close at the end of their useful life.

Figure 86. LCOE curve for energy importers (base case) assuming no capital costs



Source: Citi Research

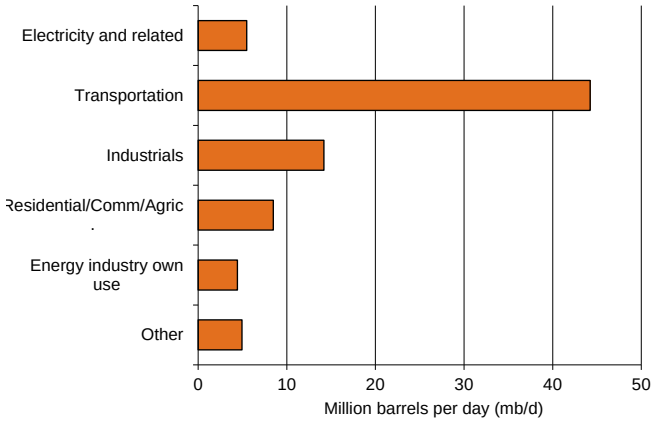
Transport and oil – not immune

While the main focus of this note is on the power generation market as the largest and fastest growing user of primary energy, there are early-stage substitutional processes at work in the transportation segment. As well as the advent of electric and hybrid vehicles, oil to gas switching is also already taking place in every aspect of transportation, be it by road, rail, sea or air. While small currently, the pace of this substitution is likely to increase.

The bulk of oil usage is in transportation…

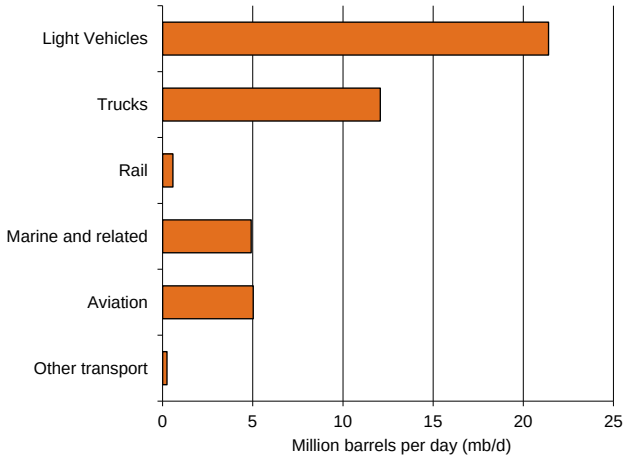
We have not added oil onto our integrated LCOE curve as very little of it is used for power generation, the vast bulk being used for transportation purposes, as shown in Figure 87 and Figure 88.

Figure 87. World oil demand by sector (2010)



Source: IEA, Citi Research

Figure 88. World oil demand for transportation (2010)



Source: IEA, Citi Research

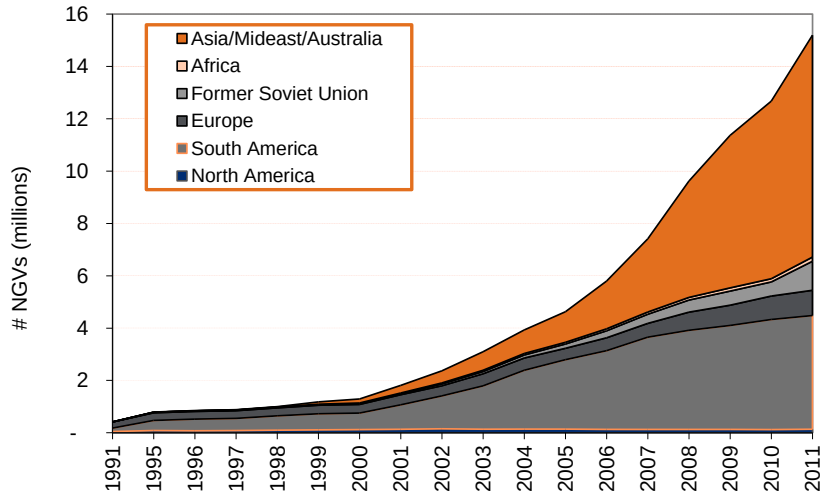
…where it dominates with 95% market share

Oil dominates the transportation usage segment of energy demand, accounting for 95% of primary energy use in transport. However, as in power generation, new technologies and fuels are starting to interfere with that dominance, most notably via natural gas vehicles, hybrids and electric vehicles, although we would stress that the level of substitution is as yet dramatically lower than in power generation, due to either far less compelling economics or a lack of infrastructure, to name but two reasons.

Substitution effects are small, but gathering pace

However, while the substitution effect is as yet small, it is beginning to gather pace, most notably in the area of natural gas vehicles (NGVs) as shown in Figure 89.

Figure 89. Number of natural gas vehicles by region (1991-2010)



Source: NGV Global, Citi Research

Substitution effects in transport are not the main focus of this note, the level of fungibility being far greater in power generation, hence our focus there. However, the transportation theme is examined in far greater detail in a previous Citi GPS report: Citi GPS: ENERGY 2020: TRUCKS, TRAINS & AUTOMOBILES - Start Your Natural Gas Engines!

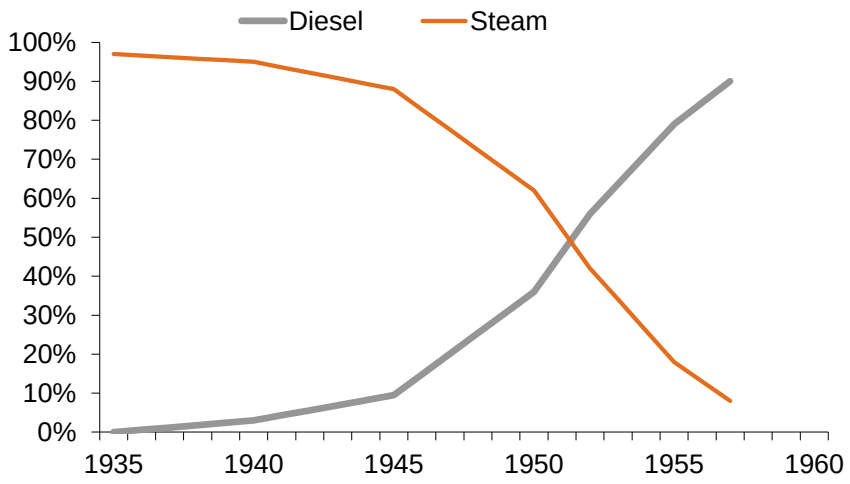
Oil to gas substitution in transportation

Rail

Transportation fuels have also suffered substitution, most notably in the switch from steam to diesel locomotives, essentially a complete switch from coal to oil.

As highlighted in that publication, in the same way as the energy consumption mix tends to shift over time in terms of primary energy (Figure 4), the same has been true historically in transportation, as demonstrated in Figure 90. This shows a similar effect, where the advent of diesel locomotives did not lead to a balanced mix with the previously dominant steam engines, rather that the latter was ultimately fully substituted by newer, more efficient and more powerful engines. This was essentially a direct coal to oil switch.

Figure 90. Diesel powered locomotives in North America (1935-1965)



Source: Ayres-Ayres-Warr, Westport, Citi Research

Many more nations are now examining the potential for LNG-powered rail transport

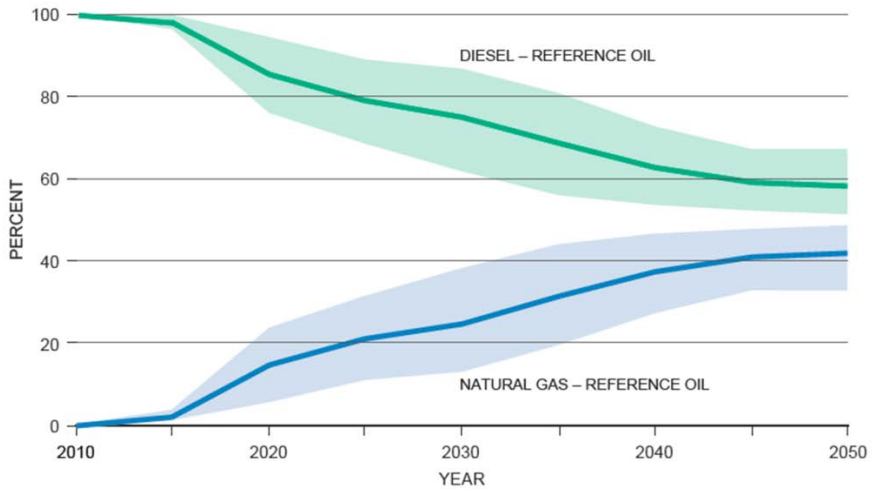
The U.S., Canada, Russia and India are all starting to test liquefied natural gas (LNG) powered locomotives. The costs of modifying a diesel-electric locomotive to running on LNG reportedly run at $600,000 to $1 million, but as one locomotive can burn 400,000 gallons of diesel in a year and on an energy equivalent basis natural gas is more than $1/gal cheaper, payback periods can be quick. Both Caterpillar and engine manufacturer Westport have announced plans to make natural gas powered locomotives, albeit no formal timetables are available as of yet.

Canadian diesel demand for powering railways is ~40-kb/d, in India it is ~50-kb/d. Canada is currently testing two LNG fuelled locomotives in northern Alberta. India is reportedly to tender for LNG powered trains, with Russia reportedly interested in supplying them. Russia itself is planning an LNG locomotive prototype that, if tests go well starting in 2013, should be followed by 39 more for delivery by 2020.

Road: natural gas vehicles

A similar process is forecast to gradually happen in road transportation by the National Petroleum Council (a powerful advisory committee to the U.S. Secretary of Energy), which recently completed a two-year study of the future of transportation fuels. The NPC assessed the economics, obstacles and the possibility of technological advancement and commercial availability of various vehicle technologies. It studied the fuel/vehicle supply chain pathways and supporting infrastructure.

Figure 91. Changes in market share of diesel and natural gas-powered trucks (Class 7&8; Reference price only



Source: NPC

In a high oil price scenario, natural gas vehicles could reach nearly 40% penetration of the U.S. heavy-duty truck segment by 2020

In its reference case the NPC projects that NGVs market penetration in the heavy-duty truck segment could reach around 15% by 2020 and just under 40% by 2040, as shown in Figure 91. Even more dramatically, in its high oil price scenario the NPC postulates that NGV's could capture just under 40% of the heavy duty (Class 7 and 8) trucking market by 2020, and nearly 50% of the market by 2040. The main driver of this abrupt substitution from oil to natural gas is fuel economics and the continued improvement in refueling infrastructure, with the switch starting from the LNG side.

Many companies are now starting to switch heavy truck fleets from diesel to LNG

This is not crystal ball gazing, but has started to become a reality. Many companies have already taken action to capitalise on the spread between oil & gas prices: Shell, FedEx, UPS and Waste Management have all announced measures to shift large parts or all of their heavy truck fleets to compressed natural gas (CNG) and/or LNG.

Citi is now forecasting that as much as 30% of the U.S. heavy truck fleet could shift to natural gas away from diesel by the end of the decade, substituting 3.6 Bcf/d of natural gas demand for 600-kb/d of diesel demand. Fuel economy mandates in the US give heavy duty vehicle (HDV) manufacturers credits for alternative-fueled vehicles based on their greenhouse gas (GHG) emissions. Carbon emissions from natural gas vehicles are about one-third lower than their diesel-powered counterparts meaning that HDV manufacturers could meet their fuel economy standards by selling natural gas rather than diesel fuelled trucks. The major truck manufacturers are moving into natural gas HDVs, with Navistar planning to offer a full range of NG HDVs by the end of 2013. The cost differential for their long haul sleeper truck should be about $70,000, so 70% higher than their current diesel

equivalent, but the bulk of the cost differential is the LNG storage tanks – an area in which substantial reductions in costs are expected once economies of scale kick in. Refueling infrastructure is coming, with Shell announcing plans for 100 LNG filling stations along the US highway system and Clean Energy Fuels announcing plans for another 150 stations.

China is also encouraging the use of NGV's

China is also undergoing the beginnings of a transformation of its trucking fleet with central and local governments encouraging the use of CNG and LNG for trucks in their gas producing regions in Xinjiang and areas around the Yangtze River Delta, which include some significant population centers such as Shanghai.

Sea: marine transportation

Bunker fuel for shipping is another area in which natural gas is expected to make inroads into oil demand in the coming years. Saudi Basic Industries Corp recently became the first chemical company to order transport carriers running on LNG. EU regulations that take effect on 1 January 2015 should mandate sulphur reductions in marine fuel used in EU waters that will require either costly scrubbing equipment or very low sulphur fuel oil or marine diesel. LNG powered ships emit no sulphur and ~20% less carbon while maintaining a healthy running cost advantage, hence their appeal.

Air: aviation

The last refuge of oil as a transportation fuel may be in the air, though even here Boeing has submitted a proposal for an LNG powered aircraft with a stretched fuselage that makes room for two LNG storage tanks. Safety and design issues should keep the plans purely theoretical for many years though, with 2040 being floated as a tentative timetable.

Transforming gas to liquids as fuel can be done, though it is expensive. Sasol's announcement that it is planning a 96kb/d gas-to-liquids (GTL) plant in Louisiana, which could come online in 2018, is yet another indication of how the huge spread between gas and oil is getting corporate attention. The $21 billion project will join a small group of others – a 32kb/d plant in Qatar, a 15-kb/d plant in Malaysia and Shell's 140-kb/d Pearl project in Qatar is reportedly running at full capacity.

Indeed, commercial passenger flights have already been undertaken using 50/50 blend of GTL fuel and conventional oil-derived kerosene jet fuel, so once again, while it is a small beginning, substitutional effects are present in every area of transportation.

Oil to gas switching outside of transport

Tight/shale oil production

The tight/shale oil production process in the U.S. is a very diesel-centric activity and producers have a robust economic incentive to shift to gas rather than diesel and this is gaining pace. EnCana estimates that producers in the US use 1.2 bn gallons of diesel each year for pressure pumping and another 1.6 bn gals is used to power the drilling rigs themselves according to Baker Hughes. This 180-kb/d of oil demand is probably the lowest hanging fruit and is not expected to be left hanging for long. One fracturing job can use as much as 185 bbls of diesel, with natural gas about $2 cheaper on an energy equivalent basis to diesel; if a well has 30 fracks then switching to natural gas could save almost $0.5 million from the cost of the well.

Petrochemicals

The petrochemicals industry is an area in which there is huge scope for substitution of natural gas for oil, and the volumes of oil consumed by the sector are significant. In 2011 global demand for naphtha was 5.9-mb/d and for liquefied petroleum gas (LPG)/ethane it was 10-mb/d. Much LPG demand is for transportation and heating, but if we assume that one-third of the IEA's reported LPG/ethane demand is for the petrochemical industry along with all of the naphtha demand, that indicates that over 9-mb/d of oil demand or over 10% of global demand is under the beginnings of a siege.

Power generation

The other area which has enormous potential for oil to gas substitution is in power generation in the Middle East. Saudi Arabia has been burning as much as 900-kb/d of crude and fuel oil for power generation in the summer, when demand for power for air conditioning is at its peak. Kuwait and Iraq have also been burning substantial volumes as their power generation demand surges past their natural gas supply capacity. Saudi Arabia has turned its upstream focus firmly to gas to address its gas needs, partly because this should free up more oil to export. Over1-mb/d or 5-Bcf/d of power generation demand in the Middle East in total can be switched to natural gas by the end of the decade. In addition, Saudi Arabia announced in May 2012 a $109 billion programme to install 132GW of new generation capacity by 2032, 71GW of which (i.e. more than half) is clean technologies such as solar PV, CSP (concentrating solar power, or 'solar thermal') and wind.

Summary

Oil is under attack from gas in all areas of transportation: rail, road, sea and air

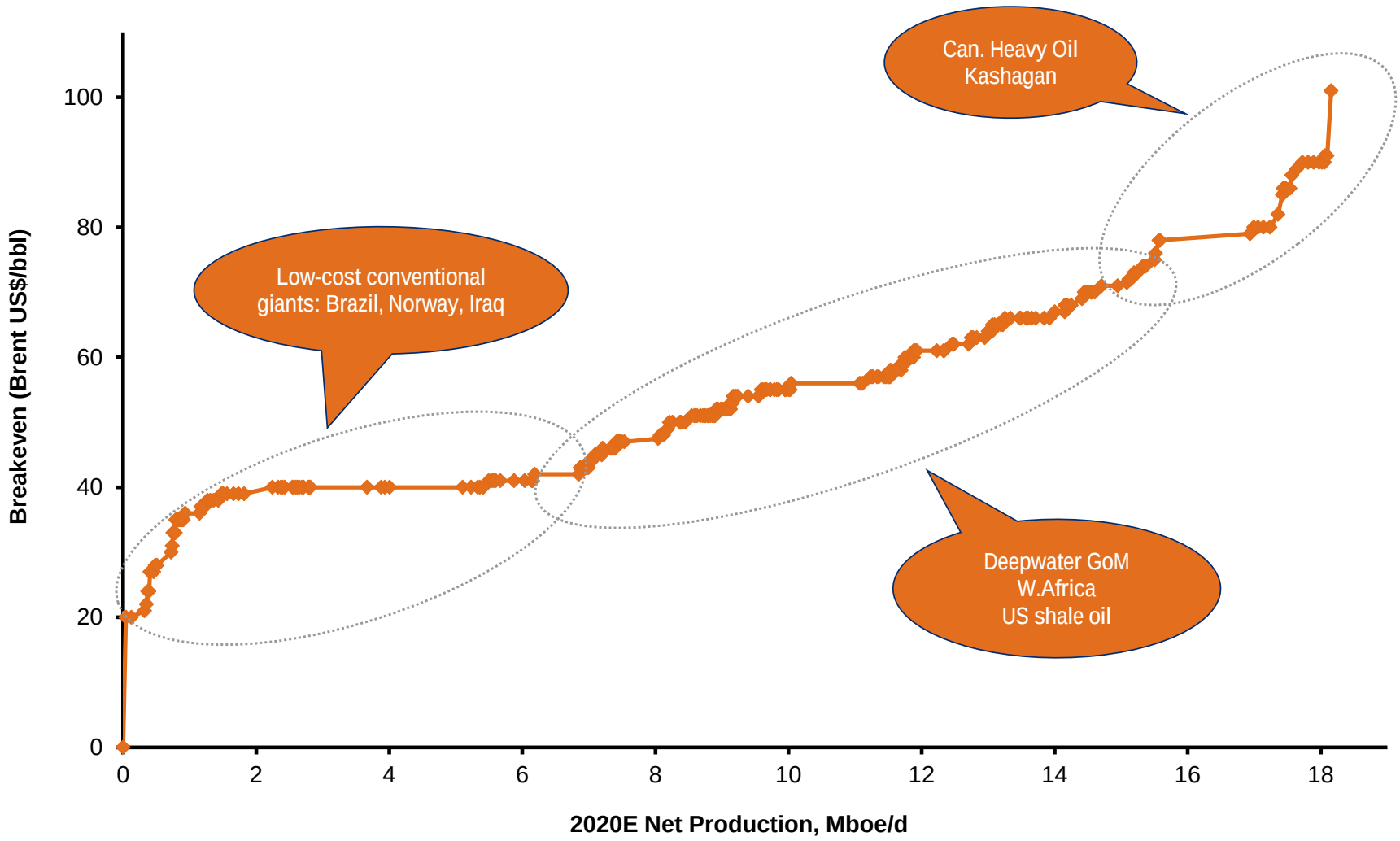
The substitution of gas for oil is a contributing factor to our bearishness on longer-term oil prices. The key drivers of this bearishness are supply side factors - the ramp up in shale/tight oil production in the US and elsewhere by end decade, Iraqi production climbing rapidly over the coming years and deep and ultra-deep water production adding an incremental 3.5-mb/d to global supplies, a 50% increase from their current supply volumes.

Demand, however, is also very much in play as the fuel economy of US cars and trucks continues to improve; at end-August 2012 the Obama administration finalised fuel efficiency standards for U.S. cars and light-duty trucks that mandates 54.5 mpg by Model Year 2025, which would more than double the fuel economy of new cars and light trucks from the October 2012 level – itself an all-time high – of 24.1 mpg. China, Japan and Europe are all mandating significant improvements in light duty vehicle (LDV) fuel economy.

Economics and lack of infrastructure suggest the pace of energy substitution in transport will be slower than in power generation, but it is beginning to happen

Transportation remains the one part of the energy complex in which oil still reigns supreme as a fuel source, but even that is now under attack in every area, be it road, rail, sea or air. Demand is being reined in by much higher fuel economy mandates, and now natural gas and other technologies are becoming increasingly viable substitutes, a process which should accelerate from here on out. Economics and the lack/cost of alternative infrastructure (for example electric vehicle charging points) suggest that oil's dominance of transport will continue far longer, while the power generation market is evolving more quickly. However, while it is earlier stage, the evolution of the transportation industry is underway, and we should be mindful of the early stage similarities, and the likely ultimate outcome. For reference purposes, we include a copy of the Citi Oil Cost Curve (Figure 92), though clearly as yet there are no other 'alternatives' shown on that curve.

Figure 92. The Citi oil-only cost curve



Source: Citi Research

Implications for utilities

Uncertainty makes for tough investment choices

The evolution of energy markets will have profound implications for utilities across the globe. Do they build must-run renewable capacity, peaking gas power plants or baseload? And if they do, how much of the time will it run, and what will fuel costs be? The challenges vary wildly by region, but are most acute for developed market utilities. Indeed, the very nature of developed market utilities is likely to change, and companies face a choice of evolving themselves within this new energy framework, or gradually regressing to become effectively state funded, rate-of-return asset-based businesses.

The implications of the evolution of energy markets for utilities are once again different in developed markets and emerging markets.

- Developed markets will see demand for electricity from traditional utilities reducing due to energy efficiency and supply from new technologies such as renewables. The latter will also lead to lower utilisation rates of conventional generation which is likely to require a change of remuneration structure. This makes new investment in conventional generation hard to justify, yet existing fleets are ageing and becoming inefficient.
- Emerging market utilities will be largely focused on expanding generation fleets to cope with increasing energy demand and the associated grid investment to accommodate this new supply and demand, as well as incorporating the nascent but rapidly growing levels of renewable energy on their systems.

Developing markets must facilitate growth, while developed markets must manage declining volumes and increased competition

Accordingly while for developing markets the challenge for utilities is managing the expansion of the generation fleet, in particular the associated grid expansion, the challenge for developed market utilities is much tougher; it is once again this issue of energy substitution, in particular the uncertainty created by the sheer pace of change in their energy mix. Large, capitally intensive, long-life conventional generation assets are in our view unlikely to be built (under current remuneration systems) given developed market utilities can have little confidence in either the utilisation rates of those facilities, or indeed the price which they will receive.

However, with change comes opportunity, and the evolution of the developed market utility sectors does present new avenues for investment and growth in terms of grid expansion, smart grid, storage, and downstream services; the question is whether utilities grasp that opportunity and evolve themselves.

Halving of the addressable market over the next 2 decades

Energy efficiency could reduce utility demand by 20% in both electricity…

Our developed markets utilities research teams at Citi continue to link gas and electricity demand to economic activity and population growth, although with a weaker link than before, a view which is in line with the utilities' medium-term financial targets. However, on top of this base case assumption, it is rapidly becoming evident that the potential for demand reduction is substantial and overall electricity consumption could decline by more than 20% across Europe through energy efficiency.

…and gas

Energy efficiency should also have a big impact on gas consumption for residential use, but overall gas demand is affected by multiple factors. Indeed, in recent years, the squeeze that natural gas demand has been under could reverse when more competitive gas supply enters the market, accelerating the drop in gas prices. Gas demand has been squeezed by declining power demand and the rising amount of generation from renewables. Low coal and carbon prices have also made gas-fired generation uncompetitive in Europe.

To tap this energy efficiency potential fully, a substantial amount of renovation needs to occur in the housing stock and office space, which will take time. This presages a prolonged period of slowly declining electricity demand, which could last more than a decade. This would be consistent with the experience of the water industry, which in the Western world through changes in consumer behaviour and consistent tariff increases has been declining by 0.5-1% per annum.

50% reduction potential in volumes sold by traditional utilities through energy efficiency and more distributed energy

The move to more distributed energy and micro-generation will also take volume market share away from centralised generation and utilities. According to the European Photovoltaic Industry Association, 15% of European electricity demand will be covered by solar PV by 2030. Adding other forms of distributed energy such as CHP, the size of the European decentralised market could grow to ~1/3 of the overall utility market within the next couple of decades.

We analyse the potential for renewable installations in both developed and emerging markets in more detail in a recent report, Citi Climate Change Universe - The $5.7trn Renewables Opportunity That Still Remains.

The proliferation of must-run renewables technologies in general has taken away material market share from traditional technologies. Figure 93 shows how the utilisation of non-renewable technologies in Europe has dropped by 7% in the last 6 years; as renewable penetration is growing in-line with EU targets and as power demand stays lacklustre, this trend is likely to persist over the coming decade.

Figure 93. Load factor of traditional technologies has been steadily declining in Europe

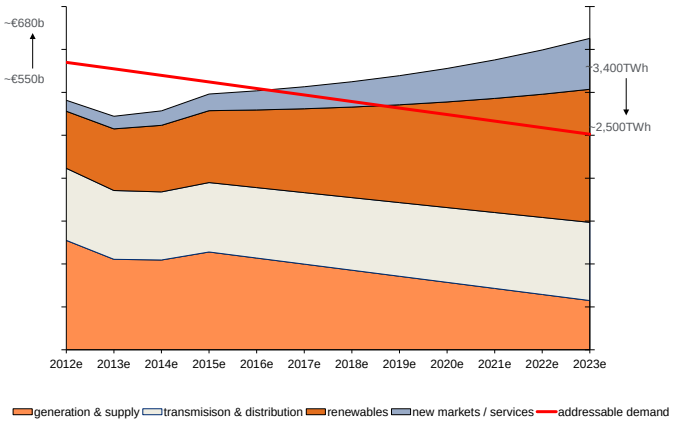
Source: ENTSO-E, NORDEL, Eurostat, NG SYS, Bloomberg, Citi Research

Developed utilities could see their addressable market halve, while emerging markets experience strong power demand growth

Combining the declining size of the electricity market in terms of volumes with the declining market share for conventional generation, we could see utilities in their current form suffer a 50%+ decline in their addressable market.

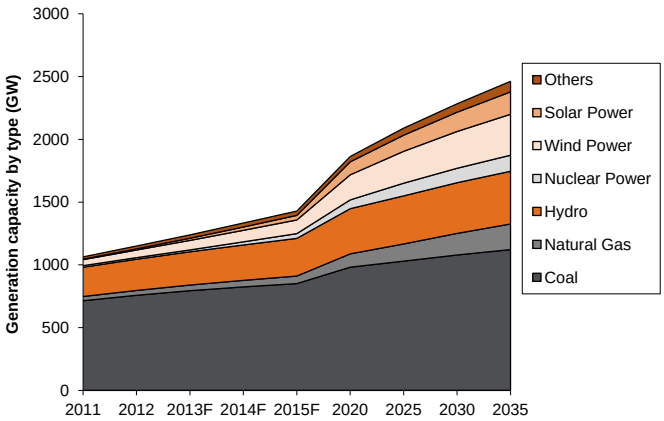
Contrast this declining trend (Figure 94) with the situation in a developing market such as China (Figure 54) where burgeoning demand for both renewable and conventionally-generated power shows the diverse issues facing utilities depending on their location.

Figure 94. The addressable market for utilities in Europe could reduce by 50% over the next two decades



Source: Citi Research

Figure 95. New power generation capacity in China by type



Source: Citi Research; BP Statistical Review of World Energy, IEA

So, in summary, while utilities in developing markets are enjoying growth via new capacity driven by increasing energy demand driven by GDP growth (and higher levels of energy intensity per unit of GDP), utilities in developed markets are seeing the size of their addressable markets shrink dramatically due to a combination of energy efficiency and competition from new technologies, which collectively could impact their addressable markets by 50% over the next two decades.

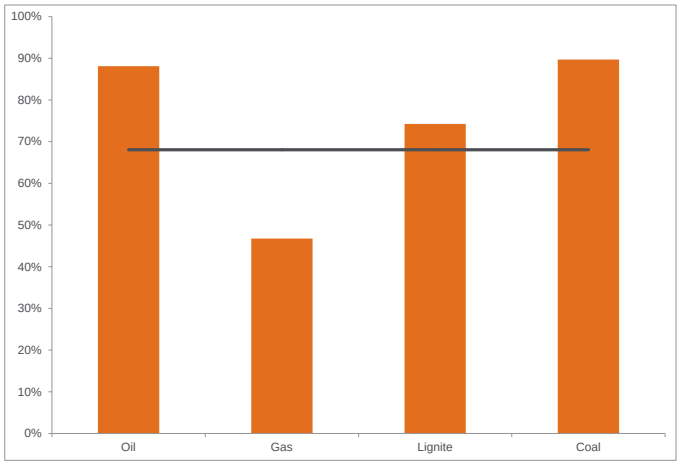
Ageing generation fleets

Generation fleets in developed markets are ageing, and need replacing

What makes this particularly problematic for utilities in developed markets is that while a reducing addressable demand makes investment in new plant hard to justify, the existing fleets are ageing and in many cases approaching the end of their useful economic lives.

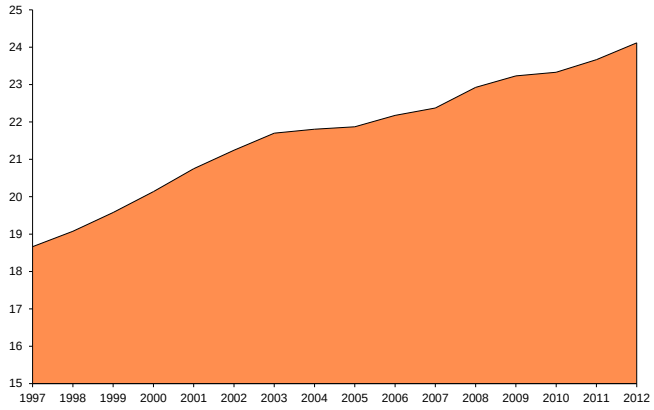
For example, the conventional thermal generational fleet in Europe has gone through more than 2/3rd of its life, as Figure 96 and Figure 97 show. So, although demand is not growing, the maintenance investment on the fleet is rising as the plants are getting older. Citi's European utilities research team estimates the average annual maintenance investment for thermal generation across Europe at ~€5.5b and for the nuclear fleet, including work done for life extensions in countries where it is allowed (e.g. UK, France), at another ~€5.8b.

Figure 96. Average used life of conventional thermal fleet in Europe



Source: Company reports, Platts, Citi Research

Figure 97. European generation fleet average age has been rising over the last 15 years



Source: Company reports, Platts, Citi Research

Towards the end of the upcoming 10 years, as more plants reach the end of their life, a significant portion will need to be replaced or upgraded, even if only to be mainly run as a back-up to renewables. In total we estimate that up to 95GW of capacity will be shut in Europe during the coming decade, the majority of which will be during the coming 2-3 years as part of the Large Combustion Plant Directive (LCPD). There are already concrete plans to replace ~1/3 of that capacity, but we estimate that ultimately about 50% would need to be replaced. The rest of the closed capacity can be replaced by renewables and the increased availability of new plants vs. the ones they replace. Plant replacement at this scale would require almost €14 billion of investment per annum over the coming decade. However, around 60% of that relates to nuclear plants, which are everywhere in Europe being built out with government support.

In order to avoid this scenario of new and little-used conventional generation, governments have two choices:

- Grid expansion to export excess (solar) electricity generated at midday; or
- Battery (or other) storage solutions, as discussed earlier

Utilities industry faces major structural challenges

It is a structural challenge to the sector's financial model when an industry with such a high fixed cost and capital cost base, which is remunerated on a volumetric basis, is seeing its market share of volumes in steady decline. It is also a structural challenge to the sector's operating model as the core purpose up until now — to generate and supply electricity — is taken up by decentralised entities or even the consumers themselves in the case of solar or CHP. Renewables and decentralised energy are impacting not only how utilities can earn money, but also what they do to earn this money.

Reinventing utilities in developed markets

Remuneration structures also need to evolve to reflect this new world

Against this backdrop remuneration structures also need to change — across the utility value chain. We see scope for more capacity payment and return-on-asset remuneration structures in generation vs. marginal plant pricing currently and flat (but ladder) tariff structures downstream vs. per MWh charging currently. Many parallels can be drawn with the experience of the Telecoms sector where revenues have switched from 'per minute' landline tariffs to line rental charges with broadband and other services offered on top.

Change brings opportunity

Change also brings opportunity, most notably in the areas of grid expansion, battery storage solutions and new downstream services. However, in the case of the latter traditional utilities, with little experience of business model innovation, will face intense competition from other industries and available returns are unlikely to match those historically delivered by conventional generation.

Evolutionary options

So, with falling addressable markets, increased competition, ageing plant and changing remuneration structures, utilities in developed markets are also likely to have to evolve into a new type of company, their options being dictated by their positioning within the value chain:

- Upstream: Decentralised energy and independent power producers (IPPs)
  - Distributed resources (solar, CHP, wind) both for households and industry that could cover 30-40% of the eventual demand
  - Renewables (onshore wind, offshore wind, biomass, hydro) to constitute a big portion of centralised energy that could cover 30-40% of eventual demand
  - Conventional generation (nuclear, CCGTs, coal) to cover some of the baseload demand as well as provide back-up to the system covering 20-40% of eventual demand
- Midstream: Super-Smart Grid
  - "Common interest" projects such as interconnectors
  - Expansion of e-mobility infrastructure
  - Local distribution and district heating networks
  - Grid stabilisation projects such as battery storage. This topic is examined in more detail in our recent report Battery storage – the next solar boom? - Germany leads the way with storage subsidies
  - On the gas side, LNG terminals, gas interconnectors and storage
- Downstream: Services
  - Energy solutions, i.e. design / planning, installation and/or operation & maintenance of energy produces both for residential and industrial use
  - Installation and maintenance of distributed generation
  - Maintenance of e-vehicle charging points
  - Contractor roles to manage energy efficiency

New business models for the Utilities industry: Revolutionary outcome, evolutionary pace as the full transformation could take 2 decades

Although we believe the trends in the direction of change for the business models are clear and have enough momentum behind them due to technological advances and consumer behaviour, the pace of change will vary substantially from country to country depending amongst other things on:

- Existing technology bias — e.g. France's reliance on nuclear (~75% of production) is so substantial, which means centralised energy should continue to cover at least 50% of demand by 2025-30.
- Natural resources — e.g. Austria covers its electricity demand with ~60% hydro generation and therefore the need for more renewables is limited.
- Level of economic activity — e.g. the relatively stronger economy of Germany can afford to go through a wholesale transformation of its energy system sooner rather than later.

Therefore while the end result in 2025-30 will most probably look revolutionary vs. the utilities market of the '00s, the trajectory of transformation will almost certainly be evolutionary from here.

For a more detailed discussion of the effects of energy evolution on utilities in developed markets, see the following recent reports:

Europe:

Pan-European Utilities - The Lost Decade: Where Next?

US:

Rising Sun: Implications For US Utilities - Solar's "Perfect Storm" A Reality, But Are US Utilities Believers?

Nuclear Shutdown - Depressed power prices, lack of heat rate expansion and low natural gas will bring more retirements in 2014 and beyond

Implications for equipment manufacturers

The choices made by utilities and upstream energy companies will have serious implications for equipment manufacturers. Some technologies and hence manufacturers will benefit at the expense of other, and moreover these effects will vary by region, with potential implications for the location of manufacturing bases and levels of competition within the industry.

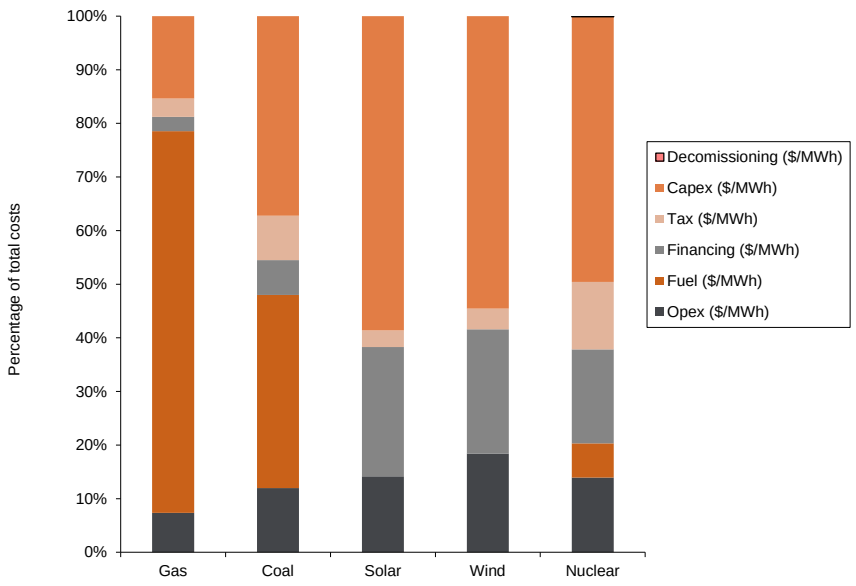
Equipment orders will be affected by changes in the generation mix

The investment decisions taken in global power generation will inevitably ripple down to the equipment manufacturer via a choice of technology. The impact of the shift in the energy mix on conventional generation is highlighted in that only 29% of the $9.7 trillion of investment in power generation forecast by the IEA out to 2035 is expected to be in 'fossil fuel technologies (coal, gas & oil), with the remainder being in renewable or clean energies.

Cost breakdowns differ markedly between technologies

Within power generation equipment, each of the four major 'mechanical' primary energy sources — Coal, Gas, Nuclear and Wind — that are viable alternatives to meet the world's growing electricity needs have different cost breakdowns. Moreover, the predictability of each of the cost categories varies over time and between different types of plant, all of which influence investment decisions, as highlighted in Figure 98. What is starkly demonstrated is the differences in upfront capex between the technologies, with gas exhibiting markedly lower upfront investment costs (proportionately) than the alternatives, all of which clearly drives the revenue line of equipment manufacturers.

Figure 98. LCOE breakdown by cost component



Source: Citi Research

A number of important points can be made in relation to each type of plant:

- Combined-cycle gas-turbine (CCGT) plants have the lowest capital cost but have the highest fuel costs by some margin. This means that their overall cost structure is sensitive to changes in the natural gas price. CCGT plants are however very flexible and can be started up quickly if necessary in order to meet peak demand. At low gas prices they are an ideal technology choice for base load generation. Construction times are relatively short for CCGT plants, typically 2 years and the low carbon content of natural gas means that they have the lowest carbon dioxide (CO2) emissions of the fossil-fuelled generation technologies. Natural gas is also free of sulphur dioxide (SO2).

- Coal-fired plants have higher capital costs than gas fired plants but generally have lower fuel costs especially when located in coal producing regions. They take significantly longer to construct than gas plants and have historically had an unattractive environmental profile from a CO2, SO2 and particulate pollutant perspective.

- Nuclear plants have high capital costs and high operating and maintenance costs. Fuel costs are very low compared to coal and gas which makes their generation costs relatively insensitive to the price of uranium. Figures from providers here previously suggested that a 50% increase in the price of natural Uranium increases total generation cost by only around 3%. This factor allows nuclear plant operators greater certainty about long-term operating costs. The high construction cost means that total costs of generation are very sensitive to discount rate assumptions.

- Wind turbine generation costs are almost entirely related to capital costs. It follows that areas of high average wind speed lead to the lowest production costs. However, as many of the most suitable locations for wind energy are remote from population centres, wind generation can require significant transmission investment and it has the disadvantage of potentially needing supplemental back up capacity.

Gas turbine technology

The IEA has estimated that 11% of the total $9.7 trillion global investment in power generation will be made into gas fired generation.

Gas turbine orders peaked in 2007

Global gas turbine ordered capacity has averaged 56GW per annum over the past decade which is considerably higher than the average of about33GW per annum ordered capacity from 1990-1999. The market trends since 2003 have remained somewhat varied with 2007 being the peak year for ordered capacity at about83GW (893 units) which dropped to 57GW (595 units) in 2012.

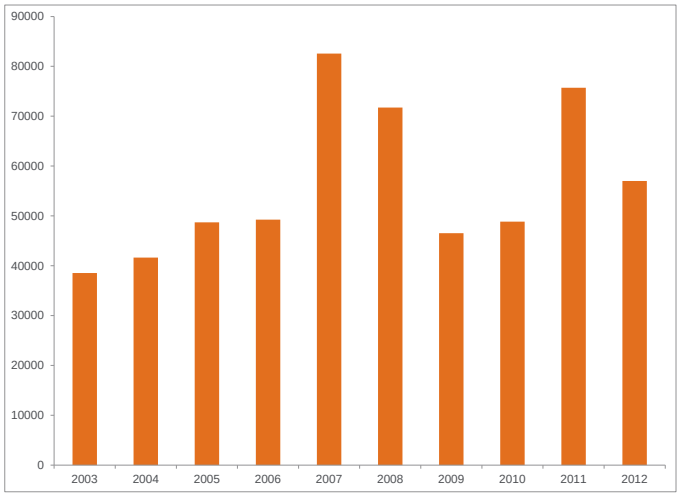
China is the world's largest market…

Geographically, China became the biggest market for ordered capacity in 2011 and ordered 18% of the total ordered capacity in 2012. From 2003-2012 ordered capacity from China has totaled nearly 52GW, i.e. around 9% of the total global capacity, of this nearly 22GW was in the last two years.

…with the US in second place, driven by shale

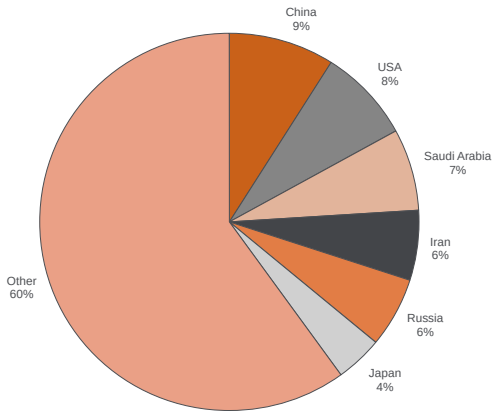
Post the surge in demand in China the US is now second largest market for ordered capacity accounting for 8% of total orders over the past decade. Despite this, ordered capacity in the US still grew 11% year-on-year to 6.2GW in 2012 of which 64% was accounted for by utility providers in the region.

Figure 99. Gas turbine ordered capacity, 2003-3012 (MWe)



Source: McCoy

Figure 100. Geographical distribution of ordered capacity of gas turbines, 2003-2012

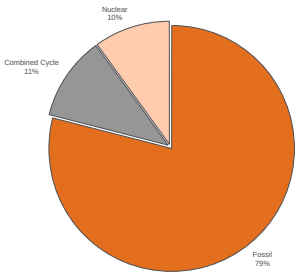


Source: McCoy

Based on cost curve analysis, it seems that at least in the US market where gas prices are considerably lower than in Europe, improving thermal efficiency alone could be enough make CCGT the low-cost generating choice. The shale gas boom has meant that margins in gas fired generation are attractive and this is likely to result in merchant investment in gas-fired plants that typified the late 1990's early 2000's U.S. 'gas boom'. However, in a world market context there are many geographies and specific market situations where gas fired generation is, and could remain, unattractive. Germany remains a prime example of this situation where some gas stations have been running for less than 10 days a year due to the high price, and the 'theft' of peak demand by solar.

Steam turbine technology

Figure 101. Steam turbine applications, 2003-2012

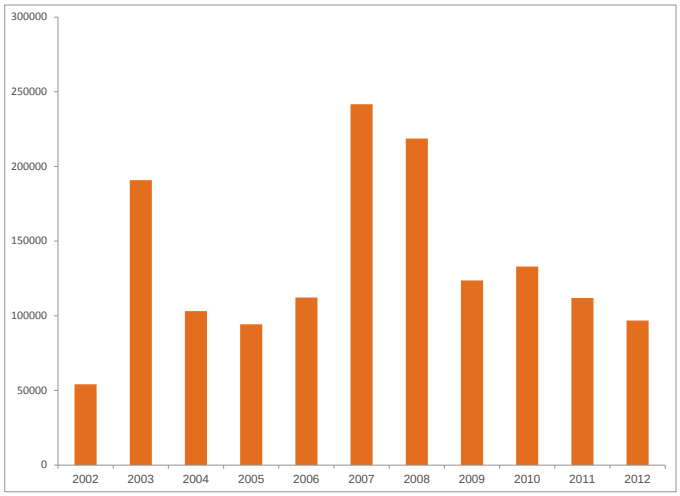


Source: McCoy

The steam market over the past decade has experienced a significant shift with China and India dominating the global market. A steam boom in China resulted in China alone accounting for nearly 60% of total ordered capacity form 2003-2012. India, the world's second largest market for steam turbines, has ordered nearly 15% of total global capacity since 2003.

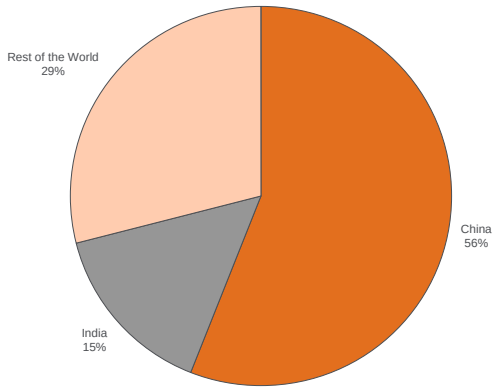
From an application perspective there are three key uses for steam turbines: coal-fired generation (where the steam turbine through steam created as water is heated from the combustion of coal), CCGT generation (where the steam turbine is powered by the hot gases after they have passed through the gas turbine) and the conventional island of a nuclear plant. Fossil powered generation is the largest application accounting for 78% of steam turbines since 2003. However, the use of steam turbines in CCGT has been increasing and CCGT accounted for 16% of the total global ordered capacity versus 9.1% in 2008. Given the relative unattractiveness of coal on the cost curve combined with the effect of possible peak coal demand in China could mean that CCGT's continue their growth as a bigger application for steam turbines.

Figure 102. Worldwide ordered capacity (MW), 2002-2012



Source: McCoy

Figure 103. Steam turbine – Worldwide ordered capacity (2003-2012)



Source: McCoy

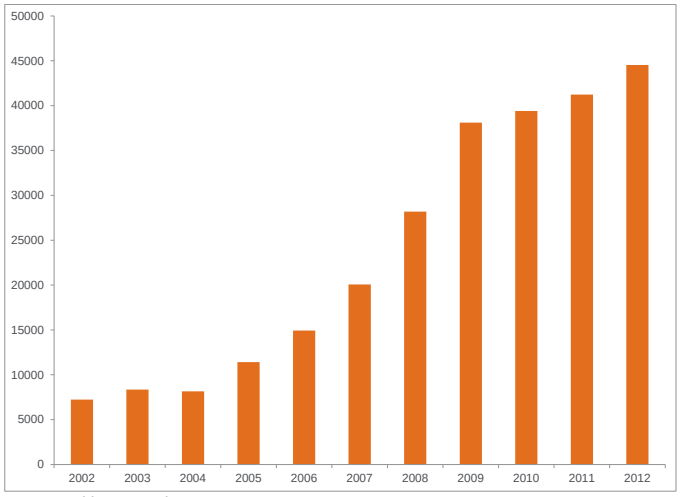
Wind Turbine Technology

China once again drives global demand

The past decade has seen considerable growth in wind turbine installations. The sudden surge in demand from 2007-2009 was largely driven by China which more than doubled new wind installations over the time and the region alone accounts for 78% of the total Asian market (itself the largest market) since 2003.

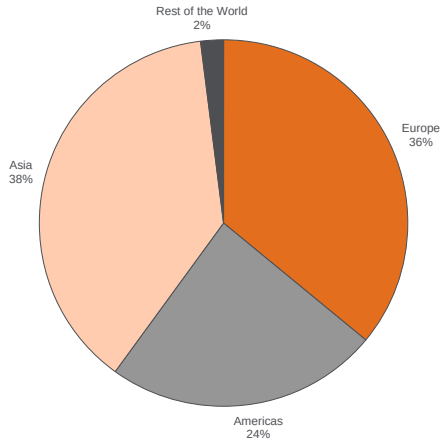
New installations within Europe have grown at just over 6GW per average from 2002-2012 but the growth has mainly been largely skewed to 2002-2008 before both the global financial crisis and the European debt crisis.

Figure 104. New installations wind power (MW) 2002-2012



Source: Citi Research

Figure 105. Geographical split of new installations, 2002-2012



Source: Citi Research

Summary

The uncertainty facing utilities translates directly into similar uncertainty for equipment manufacturers; if their customers are unable to commit to new large scale conventional power generation projects, the orders will simply not materialise.

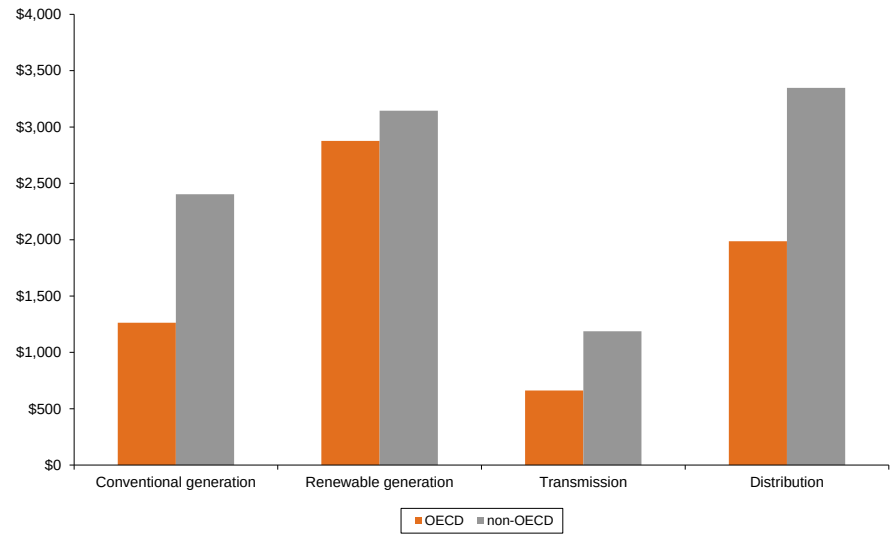
Demand shift has implications for manufacturing location and level of competition

However, what we do need to remember is the differential between developed and emerging markets; while demand for centrally generated power is set to decline in developed markets, it is still growing rapidly in emerging markets. In addition, as the bulk of new generation capacity in developed markets is in the form of renewables, developing markets remains largely dependent on new conventional generation to meet that demand growth.

Accordingly, there are several key takeaways for equipment providers:

- The geographic mix by technology is over the longer term likely to become even more polarised than it already is, with more limited demand for conventional turbines in developed markets, but strong demand continuing in emerging markets.
- This clearly has implications for the location of 'conventional' manufacturing facilities given transport costs, combined with the variation in manufacturing costs by location.
- The emerging market demand for conventional generation plant is potentially at odds with the location of many of the leading global power generation equipment manufacturers such as Siemens and GE. As we have seen in markets previously, local manufacturers are often favoured (not least due to price/cost advantages, although product life, reliability etc. is not necessarily comparable), and this is likely to mean that given the geographic shift, levels of competition and hence downwards pricing pressure are likely to increase over the longer term for developed market equipment manufacturers.
- We would also note that while emerging markets are dominated by conventional, their voracious appetite for power means that demand for renewable technologies will still exceed that in developed markets, as shown in Figure 106. This implies that, cost differentials aside, there is more flexibility in terms of manufacturing location for renewables than there may be for conventional.

Figure 106. Split of investment in generation, transmissions and distribution by OECD and non-OECD



Source: World Energy Outlook 2012© OECD/ IEA 2012

Conclusions

So why does any of this matter? Quite simply the sums of money at stake in terms of investment in energy over the coming decades are staggering, and getting a choice of fuel or technology 'wrong' could have dramatic consequences for both countries and companies, be they upstream oil & gas companies, utilities, industrial consumers, renewable developers of power generation equipment providers. Understanding the evolutionary forces at work and their interplay in a holistic manner will prove vital for anyone exposed to the energy markets.

Sums of money related to this substitutional change are vast

As discussed earlier, the IEA estimate that some $37 trillion of investment will be required in global energy supply infrastructure between 2012 and 2035. Of this $37 trillion, $16.9 trillion will be in the power industry (i.e. electricity), with $9.7 trillion of this latter figure being in power generation, the remainder thereof being accounted for by transmission and distribution. This leaves $20 trillion to be invested in 'primary energy sources such as upstream coal, oil and gas.

Even small swings have profound financial implications across the energy industry

Accordingly, a 5% swing from one fuel source to elsewhere in power generation would equate to a swing in capex of $500 billion over that period; depending on the fuel sources involved, the impact on the upstream industry in terms of demand could be at least as big again, if not multiples thereof (for gas fired generation capex is around 15% of the cost of a unit of electricity, with fuel being 70%, whereas for coal the figures are around 35% and 30% respectively).

These substitutional changes are happening now

This is not a 'tomorrow' story, as we are already seeing utilities altering investment plans, even in the shale-driven U.S., with examples of utilities switching plans for peak-shaving gas plants, and installing solar farms in their stead. The same is true for other fuels, for example the reluctance on the part of utilities to build new nuclear in the UK, or the avoidance of coal in some markets due to uncertainty over pricing, likely utilisation rates and or pollution. Even in China, we believe that coal demand is likely to peak this decade as its generation mix starts to shift. If we look at the situation facing European utilities, the future looks particularly challenging, given a potential halving of their addressable market, an ageing fleet, and deeper questions about what a utility will look like in 5, 10 or 20 years' time. In transportation, the emergence of electric vehicles, and more importantly the rise of oil to gas switching show that evolution is not restricted to the power generation market.

The impact of the energy decisions taken by companies and governments will have impacts on equipment suppliers, as well as the upstream providers of the fossil fuels on which these plants do (or don't) run. It will affect the demand for these commodities, as well as the price and hence the likely returns on upstream investments.

Emerging markets are different…

As we examined earlier the impact is undoubtedly different in developed vs. emerging economies. However even in emerging economies new technologies are taking enough of incremental energy demand (and an increasing amount going forwards) that it will have an impact on demand for conventional power generation.

…but even small shifts in focus have a material impact on incremental energy demand

For the purposes of this note it is **incremental** energy demand and supply which are important. Hence even small movements in relative economics, i.e. the positioning on the integrated cost curve, could result in a switch in customer choice which will have an important impact on the economics of some upstream projects, particularly those towards the upper end of the cost curve.

Energy markets are evolving quickly, and long term investment decisions must bear this in mind

In summary, we believe that the global energy mix is shifting more rapidly than is widely appreciated, and most importantly that consumers face economically viable choices and alternatives in the coming years which were not foreseen 5 years ago. Accordingly, we believe that long term investment into some conventional fuels must be considered in the context of at worst the risk of substitution, or more likely lower demand than might otherwise be expected, with implications on prices and hence returns of those upstream projects. Moreover, the further up the cost curve conventional fuels are, the higher these risks associated with that investment. Investing in a project with an assumed 25 year life, when new technologies will be competing with that fuel in the first quarter of that project's life entails significantly more risk than we believe is widely recognised. There will always be more subjective choice factors involved such as fuel diversity and energy independence that may offset cold, hard economics, but investors, companies and governments must consider the sea change that we believe is only just beginning.

Risks to project returns at the upper end of the integrated cost curve should not be underestimated

The shale gas boom is now widely understood and accepted, and it is notable that gas now dominates the bottom quartile of our integrated cost curve. In the second and third quartiles, however, coal is being impinged upon by both wind (now) and solar (in the coming years). Perhaps most important is that expected energy demand intersects the curve at the upper end of the second quartile, meaning that the level of risk associated with upstream projects to the right of this intersect (i.e. third and fourth quartiles) is enhanced. We should obviously remember the demand from both industry and heat related markets which also take significant elements of gas and coal supply, and hence we are not saying that these fuel sources will not be used. However, their relative attractiveness may change, their position on the cost curve is likely to move given the different evolutionary speeds of the fuel choices, all of which will have an impact on demand and hence pricing, and therefore the returns of the upstream extraction industries.

Accordingly we believe that an understanding of these dynamics and the pace of this evolutionary change is crucial for any investor, owner, producer or customer of energy; in short, just about anyone involved in or exposed to the energy industry.

Appendix 1 – Construction of LCOE curve

Aim of study is to compare the relative economics of nuclear, coal, gas, solar and wind projects commissioned by 2020

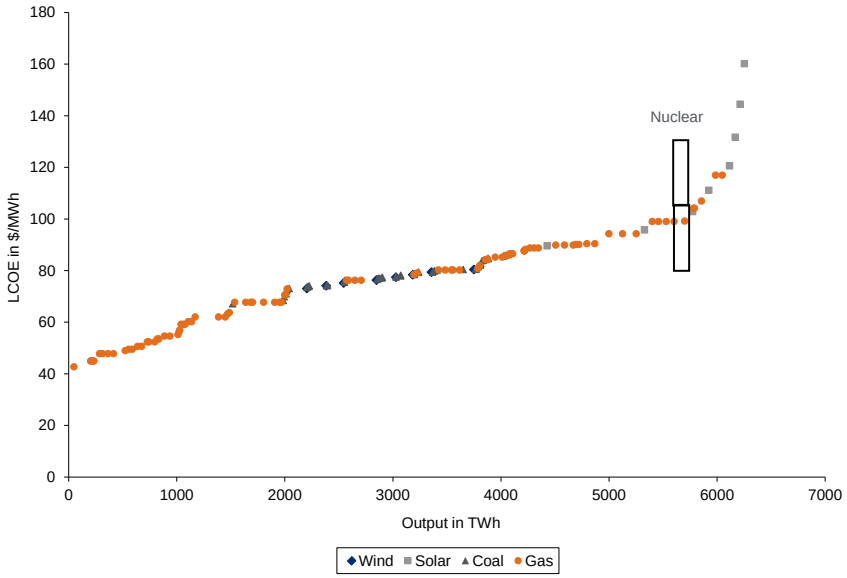
The aim of the LCOE analysis is to identify nuclear, coal, gas, solar and wind projects that come online by 2020 and contrast the relative economics of those projects when generating electricity. By considering the incremental volume of electricity generated by these projects we can estimate which projects are at risk given incremental electricity demand by 2020. It further allows us to compare the competitive dynamics of each of these fuels to explain current global consumption behaviour and forecast consumption behaviour in the future.

Relative economics measured with LCOE ($/MWh)

In order to quantify competitiveness, we compare different fuel types on the basis of levelised cost of electricity (LCOE). This allows us to compare electricity generation plants with different lifetimes – for instance a nuclear plant is likely to have a useful life of potentially ~60 years while a solar plant is likely to have a useful life of ~20 years. To quantify the incremental volume of electricity generated by 2020 we use terawatt hours (TWh), an electricity content measure that ensures comparability across all fuel types.

Volume measure with TWh

Figure 107. Incremental LCOE curve by 2020



Source: Citi Research

The key inputs into the LCOE model are

1. System costs **(these are considered as sunk costs once plant is constructed)**

2. Fuel costs **(these are considered variable costs, but only apply to coal, gas and nuclear)**

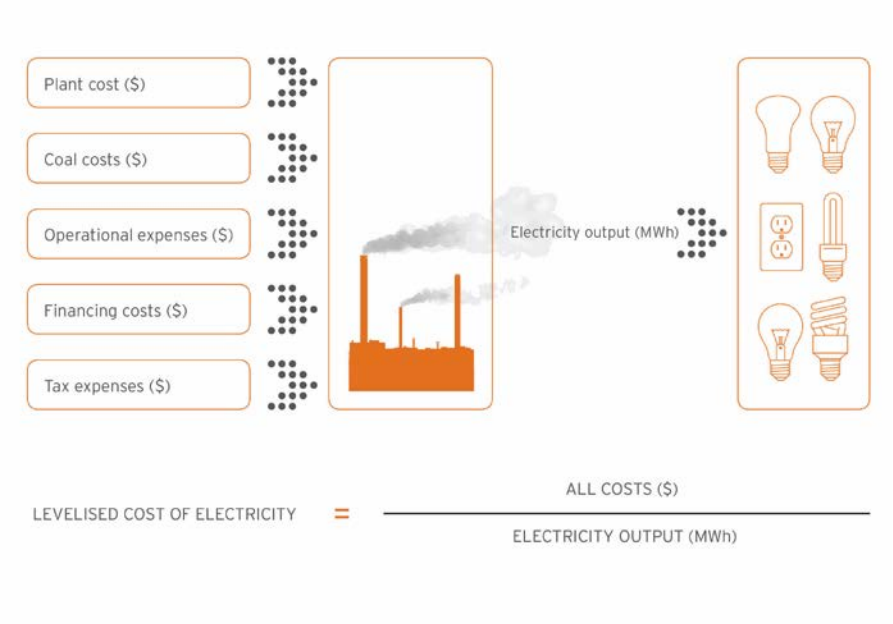
3. **Operational expenses** (these are split into variable and fixed operational expenses; however, these expenses are only incurred when then plant is running. Therefore, they are considered variable costs)

4. **Output** (this is dependent on the load factor. For renewables the load factor is a very important measure and quantifies the amount of solar and wind resource available at a specific site)

Additional expenses (a) financing costs and (b) tax expenses

On top of these expenses all electricity generating plants will incur financing costs (depending on capital outlay and financing mode) and tax expenses from the revenue generated through the sale of electricity.

Figure 108. Levelised cost of electricity calculation

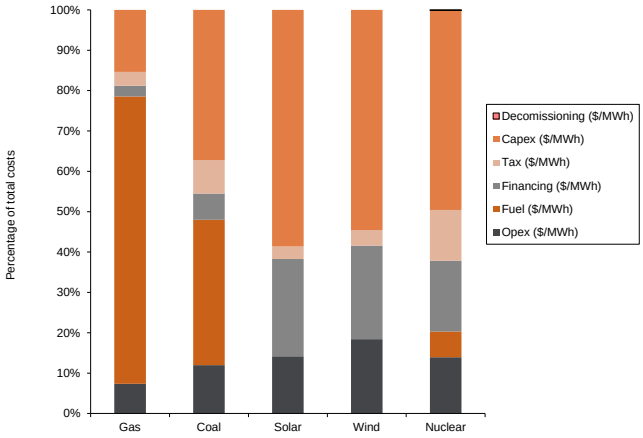


Source: Citi Research
Note: This calculation is conducted over the lifetime of the plant

Each technology geared differently to cost factors; understanding these risks is vital for an investment decision

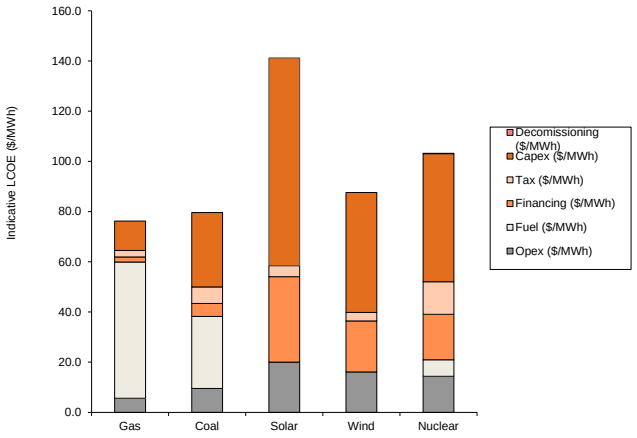
Each of the electricity generating technologies considered are geared differently to the input costs described above and hence carry idiosyncratic risk towards different external factors. Understanding these risks is vital to investing into the energy space. Figure 109 and Figure 110 show the breakdown of cost for electricity generated by gas, coal, solar, wind and nuclear resources.

Figure 109. Percentage breakdown of costs



Source: Citi Research

Figure 110. Breakdown of costs



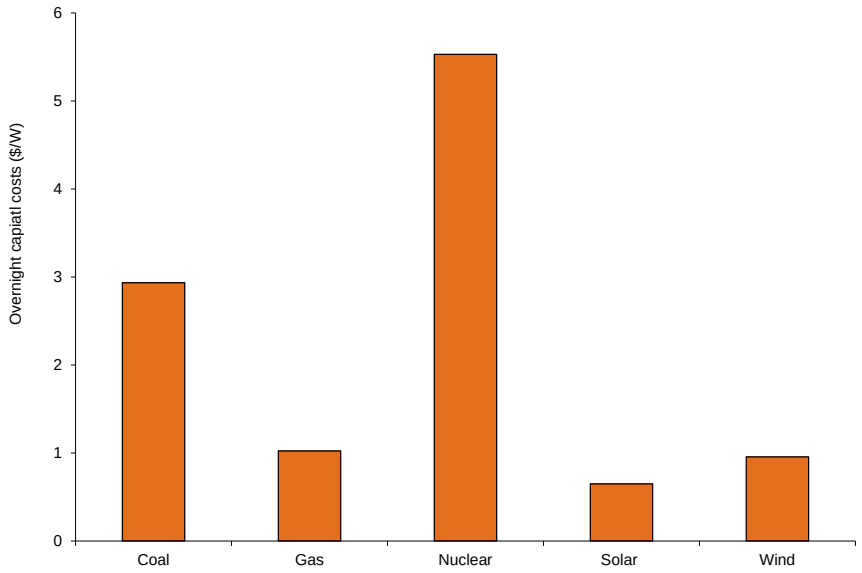
Source: Citi Research

System costs

Gas plants require low capex, while nuclear plants require over 5 times as much capex as gas plants

Figure 111 shows that the capital costs to construct an electricity generating plant vary significantly across technologies. Gas for instance requires a relatively small upfront capital investment and hence carries less capex risk than other resources. On the other hand, nuclear requires a very large upfront investment, over 5 times as high as gas on a per W basis, which makes nuclear very risky from an operational leverage point of view.

Figure 111. Overnight capital cost comparison (2020)



Source: Citi Research, EIA

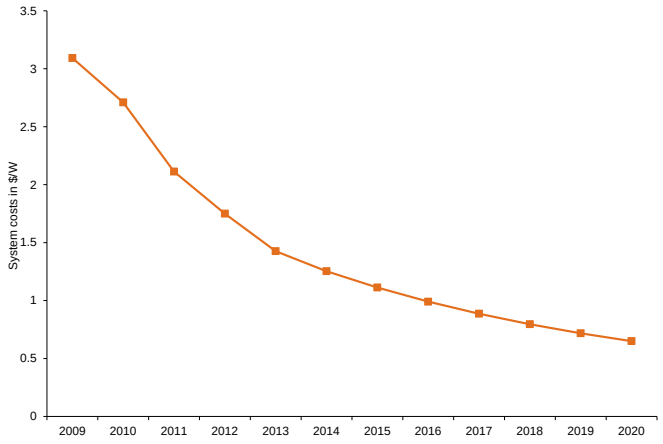
Learning rates of 2% per annum for wind and 9-11% per annum for solar

For renewables we are assuming certain learning rates which bring capital costs ($/W) subsequently down. These improvements are associated with cost reductions for solar panels, inverters and balance of system components for solar and cost reductions of wind turbine design, gearbox design and balance of system costs for wind. In comparison with solar, wind is a rather mature technology and therefore we are forecasting lower learning rates of 2% per annum for wind and 9-11% per annum for solar.

On a log scale these learning rates translate into 40% for solar and 7% for wind

Renewables specialists often plot module and wind turbine learning rates on a log scale vs. the cumulative installation base. In these terms, our forecasts imply a learning rate of 40% for solar and 7% for wind (Figure 114 and Figure 115).

Figure 112. Solar system (ex inverter) learning rates of 9-11% per annum

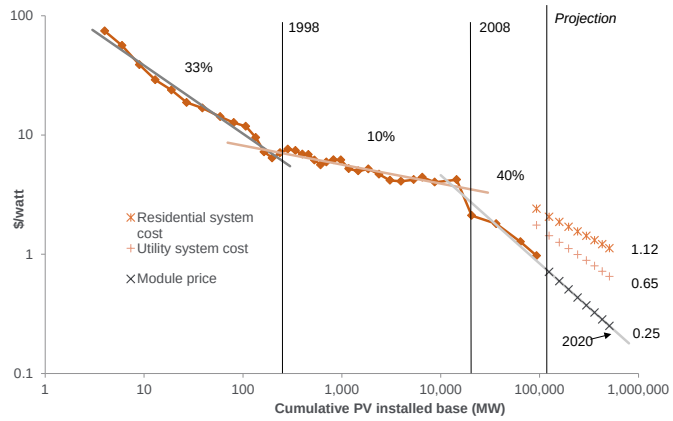


Source: Citi Research

Figure 113. Wind turbine learning rates of 2% per annum

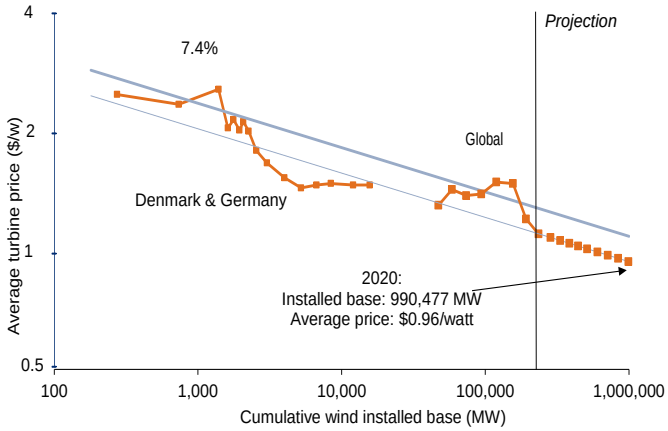
Source: Citi Research

Figure 114. Module learning rates of 40% per doubling of installation base



Source: Citi Research, Bloomberg New Energy Finance

Figure 115. Wind turbine learning rate of 7% per doubling of installation base



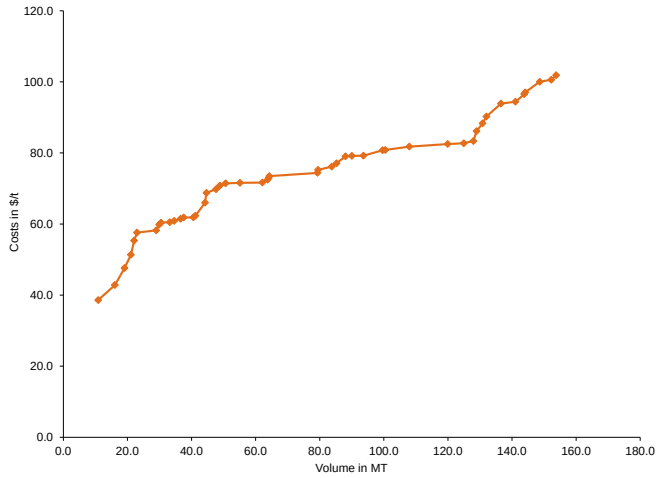
Source: Citi Research, Bloomberg New Energy Finance

Fuel costs

Consideration of over 150 coal and gas projects with individual cost and volumetric data points

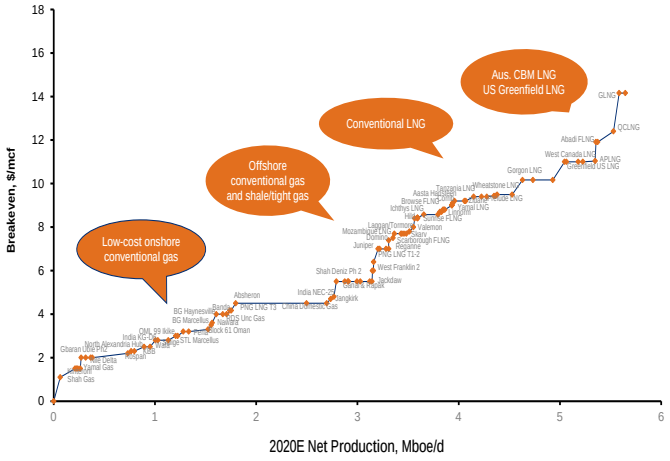
Since solar and wind do not incur fuel costs, we only consider incremental gas and coal projects. Cumulatively, we model about 150 projects that are likely to produce incremental gas and coal by 2020. The following cost curves (Figure 116 and Figure 117) show these coal and gas projects on a cost and volumetric basis.

Figure 116. Incremental coal cost curve - 2020



Source: Citi Research

Figure 117. Incremental gas cost curve – 2020



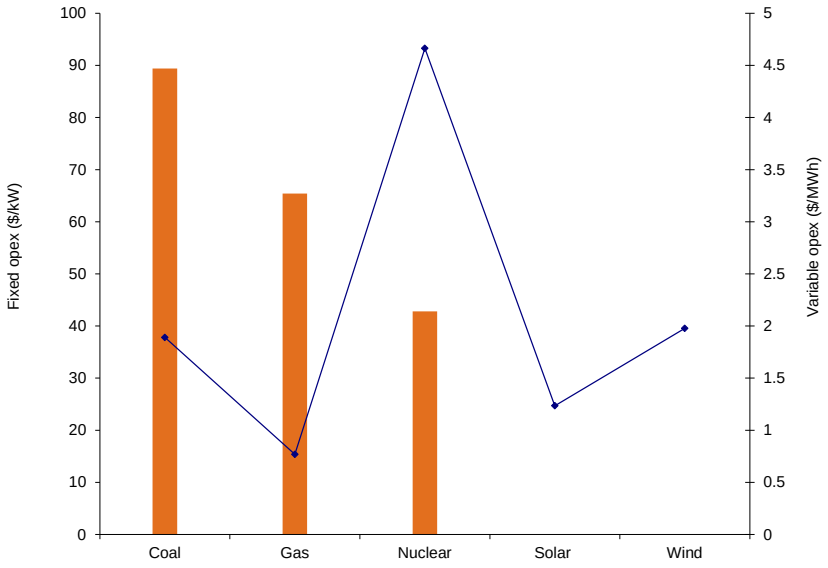
Source: Citi Research

Operational expenses

Renewables have a negligible variable opex, while nuclear has a large fixed opex component

In terms of operational expenses, conventional fuels and nuclear spend more than renewables on a variable ($/MWh) basis. However in terms of fixed opex (per kW basis) the $ amount spent for renewables is comparable to conventional generation, while nuclear shows a heavy spending pattern on fixed opex.

Figure 118. Fixed and variable operational expenses



Source: Citi Research, EIA

Output

Heat rates

Thermal efficiency for coal is projected 45%, gas is projected 60% by 2016/17

In order to model incremental electricity generation in 2020 we are assuming that best-in class heat rates today (coal and gas) will become the standard for 2020. For gas this is 60% or 5.69 MMBtu/MWh and for coal this is 45% or 7.58 MMBtu/MWh. This is a reasonable assumption given that construction periods for coal and gas stations vary between 3-4 years. Essentially we are implying that by 2016/17 these heat rates will become standard for new built coal and gas plants

What is a heat rate?

The heat rate (MMBtu/MWh) expresses how much thermal energy content (MMBtu) is required to produce a MWh of electricity. Therefore, the higher the heat rate the lower the efficiency. In order to convert a heat rate into thermal efficiency, we divide the heat rate by the equivalent MMBtu content of a MWh (3.412MMBtu/MWh)

Capacity factors

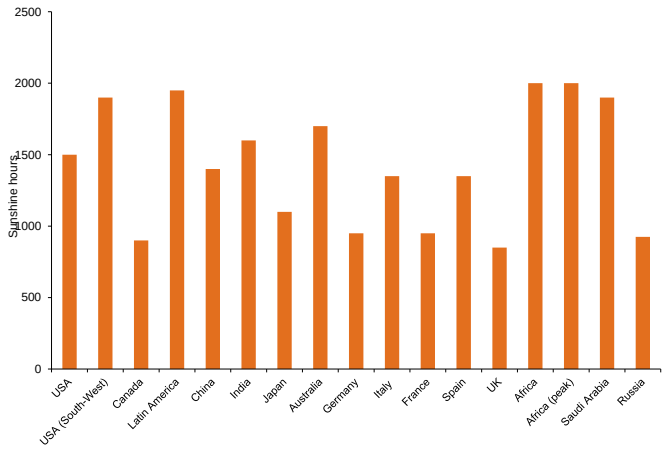
Load factor of 85% for gas, and close to 100% for coal and nuclear assumed

For conventional generation the load factor is driven by demand for consumption rather than by resource availability. Theoretically, conventional and nuclear plants are run as close to 100% as possible with the exception of gas peakers. The major factor limiting electricity production to levels below 100% is the fact that electricity demand has to be matched to electricity supply in order to avoid frequency fluctuations that jeopardise the stability of the grid system. Since gas has a relatively high marginal cost of generation (Figure 110) it is often used a transitory fuel and hence many regions do not run gas flat out. For the purpose of our 2020 electricity curve, we are assuming a load factor of 85% for gas and close to 100% for coal and nuclear.

Resource availability limits renewables capacity factors. Sunshine hours and wind capacity factors vary by region

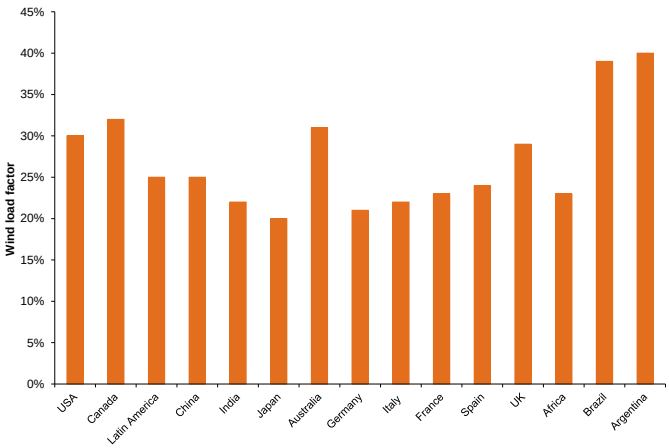
For renewables, the limiting factor is the availability of sunshine and wind resources. These resources vary across different countries. The sunniest regions (Africa and the Middle East) have around 1,800-2,000 equivalent sunshine hours per year (capacity factor: 20-22%) while less sunny regions such as the UK and Germany have 900-1,000 sunshine hours (capacity factor: 10-11%); see Figure 119. In terms of onshore wind resources, windier regions such as Brazil and Argentina have capacity factors of close to 40% while less windy regions, such as Japan, only have 20% (See Figure 120).

Figure 119. Solar sunshine hours per annum



Source: Citi Research

Figure 120. Wind capacity factors



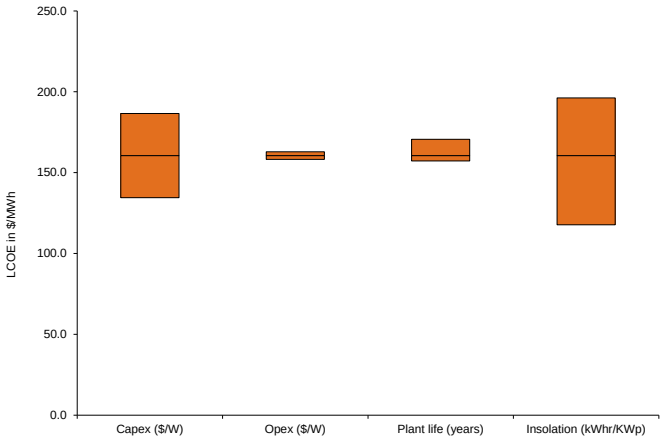
Source: Citi Research

Appendix 2 – Base case and optimistic case

Solar and onshore wind are very sensitive to the load factor assumption

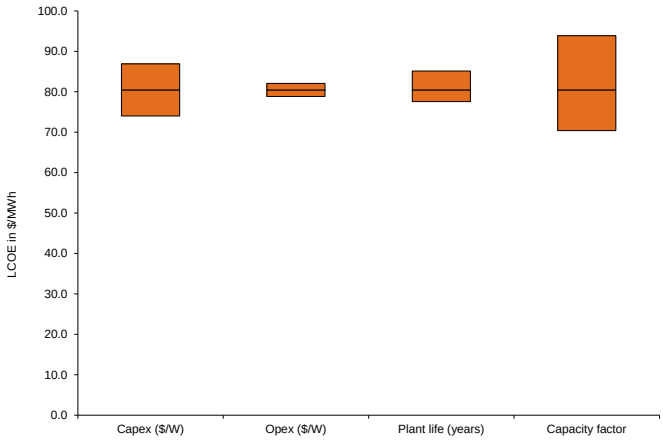
As shown in the sensitivity analysis the load factor on renewables has a very big impact on cost and competitiveness of solar and onshore wind (Figure 121 and Figure 122). For this reason we consider two cases: 1) one where we use standard to pessimistic assumptions about solar/onshore wind load factors and 2) one where we use optimistic assumptions for solar/onshore wind load factors.

Figure 121. Solar LCOE is highly sensitive to insolation/sunshine hours



Source: Citi Research

Figure 122. Wind LCOE is highly sensitive to capacity factor



Source: Citi Research

Figure 123. Base and bull case assumption

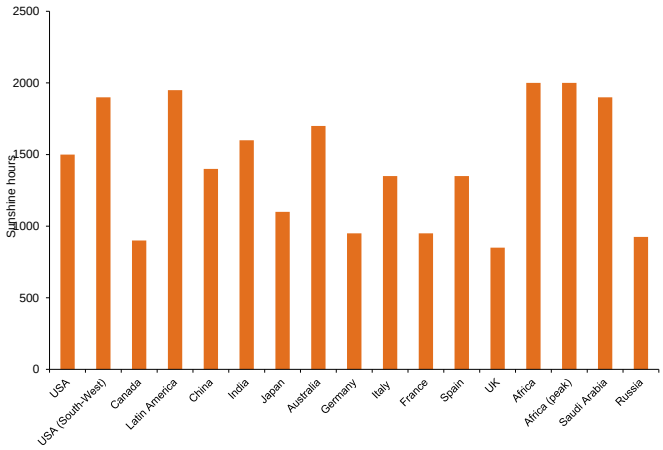
	Solar	Onshore wind
Base case	12.5% (1,100 sunshine hours)	28%
Bull case	17% (1,500 sunshine hours)	32%

Source: Citi Research

For the base case we assume a capacity factor of 28% for onshore wind and 1,100 sunshine hours for solar (12.5%) while for the optimistic case we assume a capacity factor of 32% for onshore and 1,500 sunshine hours for solar (17%).

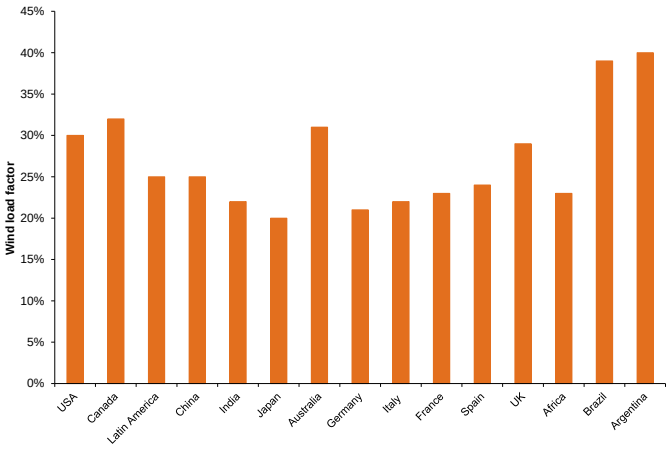
To ensure our assumptions are reasonable we compare them to country specific resource availability in Figure 124 and Figure 125. For solar we see most incremental installations occurring in Japan (1,100 sunshine hours), China (1,400 sunshine hours) and the U.S. (1,500-1,900 sunshine hours) while wind will see the bulk of installations spread across the U.S. (30%), China (25%), India (22%) and Latin America (Brazil: 39% and Argentina: 40%). Because we aggregate the capacity factor weighted by incremental installations to 2020, a base case of 12.5% for solar and 28% for onshore wind seems reasonably conservative. The bull case is also in line with the geographical location where we see the majority of incremental solar and onshore capacity being added.

Figure 124. Solar sunshine hours per annum



Source: Citi Research

Figure 125. Wind capacity factors



Source: Citi Research

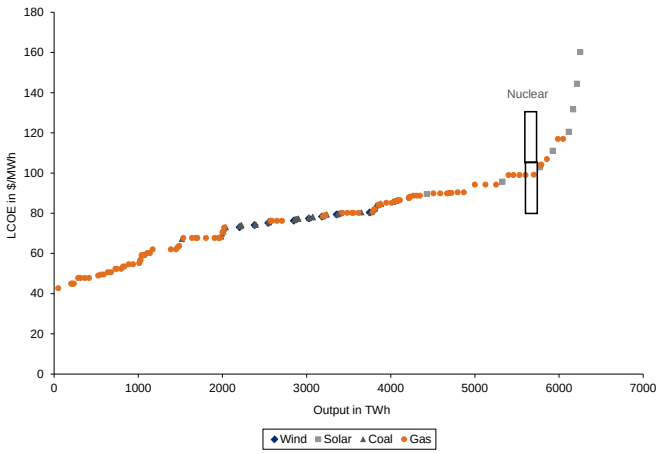
In the base case, solar threatens 3rd quartile gas, in the bull case solar has the potential to threaten 2nd quartile gas by 2020

With these capacity factor assumptions, we arrive at a base case and an optimistic case (Figure 126 and Figure 127) where the difference lies in the competitiveness of renewables. In an optimistic world we would see onshore wind and especially solar become competitive at a much faster rate threatening 2nd quartile gas when we reach 2020. In the base case, solar starts off uncompetitively above $100/MWh and gains competitiveness as capex costs reduce over time. In 2020, the base case assumes solar to be able produce electricity at a cost of $90/MWh threatening 3rd quartile gas.

Wind already threatening 3rd and 2nd quartile gas and in both bull and base cases competitive with coal

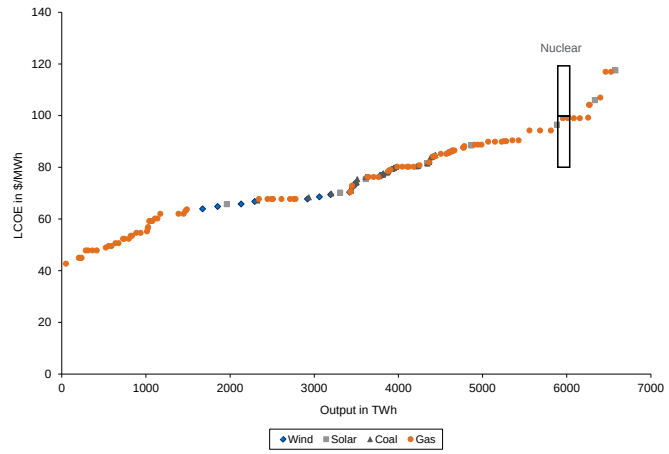
The gains for wind are somewhat less impressive because wind starts off at a better competitive position. In the base case, wind will be able to generate electricity at $75/MWh while the bull case assumes a generation cost of $70/MWh. However we note that wind is already threatening 3rd and 2nd quartile gas, and is highly competitive with coal.

Figure 126. Base electricity curve



Source: Citi Research

Figure 127. Bull case electricity curve



Source: Citi Research

Appendix 3 – Marginal electricity generation curve

Marginal electricity curve to offer insights into current consumption patterns

To understand current consumption patterns we construct the electricity curve on a marginal basis for the case that capex has already been spent on generation plants. This analysis rationalises current consumption trends and can be used to contrast short-term consumption behaviour (marginal curve, Figure 126) with long-term investment decisions (full electricity curve, Figure 128).

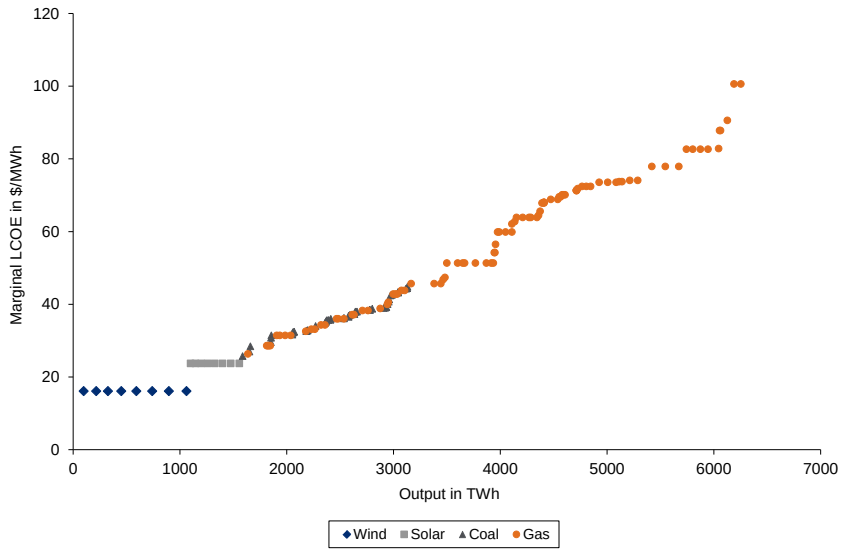
Coal more competitive than gas on a marginal basis, explains preference of coal over gas in Europe

The marginal electricity curve shows a very different picture than the full electricity curve and helps us explain current consumption behaviour. Currently, coal is considered more competitive than gas (exception is U.S. where shale gas exploration has reduced gas to $3-4/MMBtu). Since current competitiveness and consumption decisions are based on marginal cost of electricity generation, we observe that most countries (especially Europe) that have access to both coal and gas prefer to consume coal in existing stations.

Full electricity curve reveals structural long-term challenges of coal value chain

However, from a reinvestment point of view, we argue that gas has a competitive edge and the risk that future coal plants (particularly in developed markets) are not built is greater, with clear implications on the whole coal value chain from upstream coal extraction downwards.

Figure 128. Marginal electricity curve



Source: Citi Research

Appendix 4 – Sensitivity analysis

Sensitivity analysis allows investors to understand upside and downside risk of each resource type

In order to understand the risks associated with investing along the value chain of any of the resources under discussion (nuclear, coal, gas, solar and onshore wind) we assess LCOE sensitivity with respect to specific factors. For each resource we assume a high (cautious case) and a low (optimistic case) scenario under which the LCOE ($/MWh) will turn out higher and lower, respectively, to our base case.

For instance, gas competitiveness is very contingent on gas prices; hence investment along the chain (from exploration to distribution) only recommended when the view is that gas prices will remain low

This analysis allows investors to understand which factors will make the largest impact on competitiveness of each resource. In the case of gas for instance we find that the LCOE is most sensitive to gas prices (Figure 128). Hence an investor can overlay their own assumption that gas prices will be low in the US (due to shale gas exploration for instance) and therefore come to the conclusion that this factor will materially impact the competitiveness of gas – and with this the competitiveness along the value chain from gas exploration to gas distribution. This upside risk scenario can also be applied to the downside.

On the other hand gas competitiveness is not materially contingent on capex

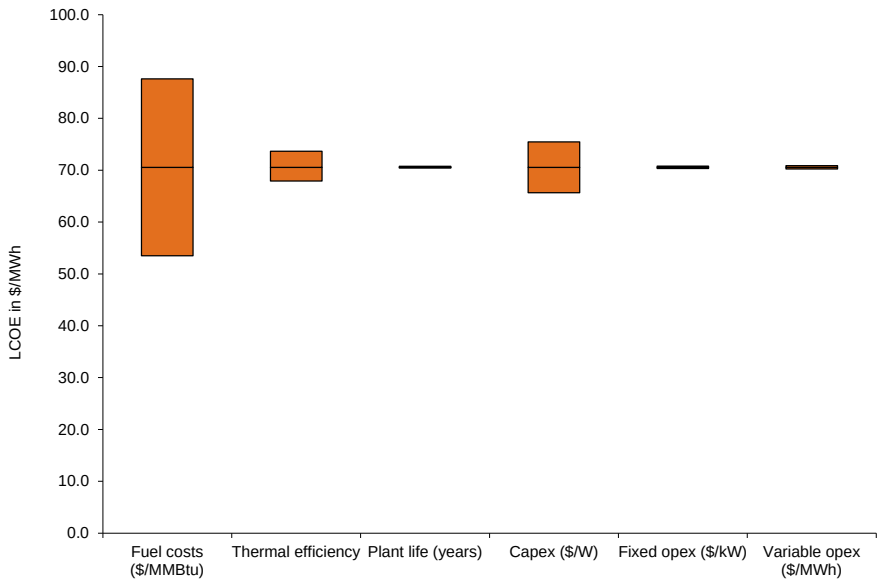
Conversely an investor might have a view on the thermal efficiency of gas plants and assume that we will see significant improvements in the next few years which could bring efficiencies up to 65% (overnight construction with a construction period of 3-4 years). In this case the impact on LCOE and competitiveness of gas projects is only marginal (see Figure 129).

Figure 129. Low and high case assumption for gas sensitivity analysis

	Low	Base	High
Fuel costs ($/MMBtu)	3.0	6.0	9.0
Thermal efficiency	65%	60%	55%
Plant life (years)	45	40	35
Capex ($/W)	0.7	1.0	1.3
Fixed opex ($/kW)	13.8	15.4	16.9
Variable opex ($/MWh)	2.9	3.3	3.6

Source: Citi Research

Figure 130. Gas LCOE sensitivity



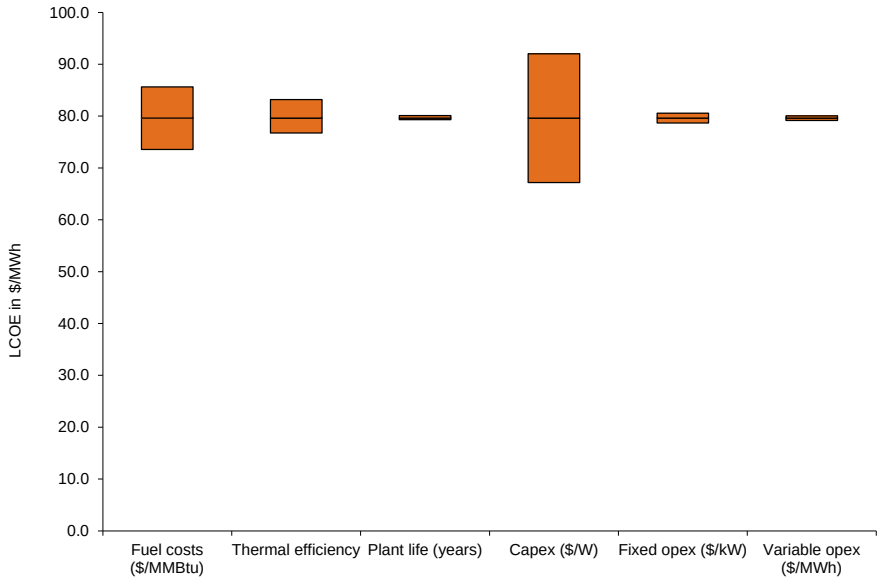
Source: Citi Research

Figure 131. Low and high case assumption for coal sensitivity analysis

	Low	Base	High
Fuel costs ($/t)	60.0	80.0	100.0
Thermal efficiency	50%	45%	40%
Plant life (years)	45	40	35
Capex ($/W)	2.1	2.9	3.8
Fixed opex ($/kW)	34.0	37.8	41.6
Variable opex ($/MWh)	4.0	4.5	4.9

Source: Citi Research

Figure 132. Coal LCOE sensitivity



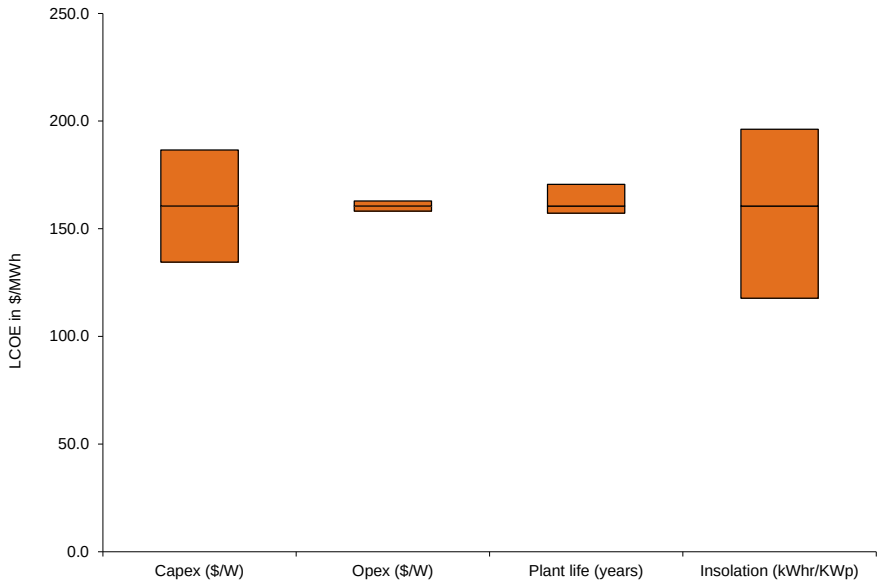
Source: Citi Research

Figure 133. Low and high case assumption for solar sensitivity analysis

	Low	Base	High
Capex ($/W)	1.14	1.43	1.72
Opex ($/W)	0.022	0.025	0.027
Plant life (years)	22.5	20.0	17.5
Insolation (kWhr/KWp)	1500.0	1100.0	900.0

Source: Citi Research

Figure 134. Solar LCOE sensitivity



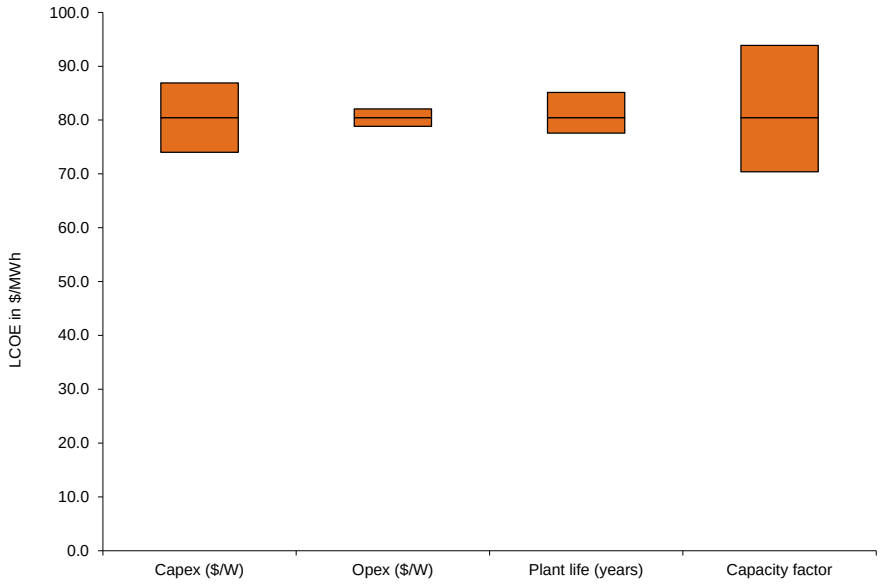
Source: Citi Research

Figure 135. Low and high case assumption for wind sensitivity analysis

	Low	Base	High
Capex ($/W)	1.50	1.66	1.83
Opex ($/W)	0.036	0.040	0.044
Plant life (years)	22.5	20.0	17.5
Capacity factor	32%	28%	24%

Source: Citi Research

Figure 136. Wind LCOE sensitivity



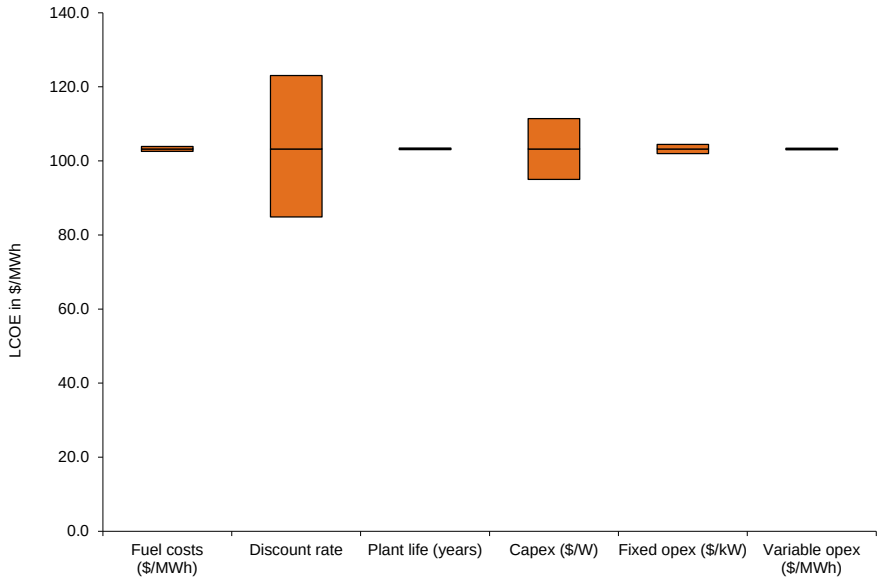
Source: Citi Research

Figure 137. Low and high case assumption for nuclear sensitivity analysis

	Low	Base	High
Fuel costs ($/MWh)	5.9	6.6	7.3
Discount rate	8%	10%	13%
Plant life (years)	65	60	55
Capex ($/W)	5.0	5.5	6.1
Fixed opex ($/kW)	84.0	93.3	102.6
Variable opex ($/MWh)	1.9	2.1	2.4

Source: Citi Research

Figure 138. Nuclear LCOE sensitivity



Source: Citi Research

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Key Insights regarding the future of Energy

NATURAL RESOURCES

History tells us that typically in the world of energy we don't tend to move gradually to a more balanced energy mix as new fuels or technologies come along, rather we tend to over embrace those new technologies at the expense of incumbent technologies or fuels. / We are currently in the midst of a more balanced energy mix but as conventional fuels become gradually more scarce and expensive and as new technologies improve, the long term transformation becomes more inevitable.

INFRASTRUCTURE

Infrastructure spend has been centered on "conventional" technologies (coal, oil and gas) keeping risks to upstream projects lower. / Energy substitution away from conventional towards renewables and the pace of evolution is vitally important to understand as the value at risk from a plant or the fuels that supply them becoming uneconomic in certain regions — both in terms of upstream assets and power generation — is enormous.

COMMODITIES

While coal usage was replaced in transportation by oil, it continues to play a dominant role in power generation while the falling price of gas in some markets has made gas-fired electricity more favourable. / The impact of energy decisions taken by corporates and governments in power generation will have an impact on the upstream providers of the fossil fuels on which these plants will (or won't) run, affect the demand for these commodities, as well as the price and the likely returns on upstream investments.