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It is time to slam on the brakes.

—Felipe Calderón, President of Mexico

Pricing Climate Change Risk Appropriately

CFA charterholders are well positioned to understand the economics of climate change, which is fundamentally a problem of risk management. The key conclusion of recent scientific and economic research is that in our risk-averse society, carbon emissions should be priced at high levels *immediately* because of the real risk of catastrophic damages. The appropriate price is the expected present value of the uncertain future damages those emissions will create.

But that simple statement hides a raft of hidden assumptions and complexities. For example, a price can be optimal only in the context of a plan because future damages are a function of the levels of greenhouse gases over time, not simply today's emissions. If society were to price emissions at a high level in the near term, we would expect the damages caused by today's emissions to be less than if society failed to price emissions for an extended period. Complexities aside (I will return to them later), the optimal policy today can be summarized as setting the tax on emissions equal to the present value of the future damages that the emissions are expected to cause. Under this policy, nature's emissions-absorbing capacity—a scarce resource—is used up appropriately over time.

Recent research has highlighted how the present value of future damages depends on societal risk aversion and low probabilities of disaster. We are all filling up a common reservoir of limited, if unknown, capacity to absorb emissions safely, and we need to decide how much to charge each other for filling it up. Any underpricing early on will inevitably be compensated through overpricing (relative to the optimal path) later on. If the reservoir overflows, a catastrophe could ensue. At last year's UN climate conference in Cancún, Mexico, Felipe Calderón, the president of Mexico, told the attendees that we should charge a high price; with respect to climate change, he said, "It is time to slam on the brakes."

It turns out, perhaps intuitively, that the optimal amount to brake—that is, the appropriate price for carbon emissions—depends critically on how risk averse society is. In this brief review of the recent literature on the economics of climate change, I attempt to relate some of the new findings to finance topics familiar to CFA charterholders—for example, the equity risk premium puzzle: the surprising degree of societal risk aversion as evidenced globally by the high historical returns to risky assets.

Uncertainty about Catastrophic Risks

Economists Frank Ackerman and Elizabeth A. Stanton offer the following summary:[1]

> Recent scientific research has deepened and transformed our knowledge of climate change. The Earth's climate is a complex, nonlinear system with dynamics that cannot be predicted in detail—including, among other hazards, the possibility of thresholds at which abrupt, irreversible transitions could occur. A range of feedback effects intensify the warming caused by rising concentrations of greenhouse gases, leading to a rapid, though perhaps irreducibly uncertain, pace of climate change. There is also a growing understanding of the numerous harmful impacts that are expected before the end of this century, even at the most likely rate of climate change, and of the additional, catastrophic outcomes that could result—with lower but non-trivial probability—if climate change proceeds more rapidly. (p. 64)

Economic theory tells us that the optimal policy is to price risk immediately and appropriately. Until recently, however, economists focused on the expected outcome and the uncertainty caused by economic growth and not on the uncertainty caused by climate impacts because they assumed that economic growth would dominate climate impacts over a long horizon. These models did not put much weight on catastrophic outcomes. According to the Ackerman–Stanton summary of recent research, "Long-term catastrophic risk is the

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subject of some of the most important recent developments in climate economics" (p. 6).[2] The latest economic research is drawing attention to the important role of worst-case climate change outcomes, about which there is tremendous uncertainty. Moreover, until very recently, economists assumed that society has a very high tolerance for risk—in fact, a value totally inconsistent with market risk premiums. The typical "reasonable" risk-aversion assumption used by economists would imply an equity risk premium in the range of 13–19 bps, not the 600–800 bps that we have seen in equity markets historically. In recent years, the combination of the recognition of uncertainty in worst-case outcomes and the need to incorporate risk aversion realistically has had a powerful impact—namely, to raise the appropriate price of emissions significantly.

Another important development has to do with discounting and the risk aversion embedded in utility functions. Appropriately, researchers have started to apply principles of risk pricing to climate risk. In particular, outcomes should be not only probability weighted but also weighted by the marginal utility in the state of nature in which they occur. In other words, the appropriate discount rate for cash flows depends on their risk profile. Equities should—and do—have low prices (and high expected returns) because their cash flows are discounted by society at high rates. The reason has to do with the anti-insurance aspect of equities: Their cash flows are highest in good states of nature whereby the value placed on the cash flows is low. In contrast, efforts to mitigate climate change by pricing carbon emissions will be most valuable to society if climate change turns out to have catastrophic consequences for society's well-being. Because of this insurance aspect, society should be willing to pay higher prices for climate change mitigation.

Until recently, economists assumed a very low level of risk aversion, a level too low to be consistent with the high rate of return on equities. Calibrating the curvature of the utility function in order to match both the equity risk premium and the risk-free rate implies a much higher societal risk aversion, which, in turn, implies lower discount rates for projects that have high payoffs primarily in bad states of nature (e.g., climate mitigation). Under this calibration, the appropriate price for carbon emissions is much higher than the values in earlier studies that assumed high risk tolerance.

CRRA Utility

The rather complex explanation of why economists typically assumed very high levels of risk tolerance has to do with their use of the standard constant relative risk aversion (CRRA) utility. This utility function uses one parameter—a degree of curvature—to try to capture two very different aggregate economic behaviors: intertemporal substitution and risk aversion. Intertemporal substitution (the willingness to postpone consumption today for consumption in the future) determines the risk-free interest rate. Risk aversion determines the willingness to accept risk and, therefore, the equity risk premium. Obviously, interest rates and equity risk premiums are two of the most fundamental economic phenomena, about which we have extensive historical observations. As is well known in the finance literature, however, CRRA utility cannot come close to simultaneously fitting both the low real market interest rates, which reflect a high degree of intertemporal substitution and thus a low curvature of utility over time, and the high equity risk premium, which reflects high risk aversion and a high degree of curvature across different states of nature. This well-known inability of CRRA utility to fit both phenomena at the same time—first recognized two decades ago in the financial economics literature—is called the *equity risk premium puzzle*.

The rigidity of CRRA utility is also a serious problem in climate economics because both intertemporal substitution and risk aversion are key determinants of the appropriate price for carbon emissions, which when emitted today create increased risk in the distant future. Under CRRA utility and typical assumptions about economic growth and damages, the interest rate effect of increasing curvature dominates. Thus, increasing the risk aversion in the context of CRRA utility generally implies higher discount rates and (counterintuitively) reduces the appropriate price for emissions. There is no good reason to impose the rigidity of CRRA utility. In the mid-1980s, economists developed a more general class of utility function (Epstein–Zin being the leading example) that allows calibration to realistic values for both interest rates and the equity risk premium. Calibrating utility functions to these market reflections of aggregate societal behavior suggests much higher risk aversion and higher prices for emissions than in previous economic models.

If governments were to price carbon emissions appropriately, the costs borne by society today would balance the potential benefits to future generations. But what is the appropriate price? No one knows. What we do know is that it is significant. A recent U.S. government study[3] suggested a range of values centered on $21 per metric ton of carbon dioxide. This study relied on models that use the CRRA utility function; in a section titled "Limitations of the Analysis," the authors list "incomplete treatment of potential catastrophic damages" and "risk aversion" and go on to point out that "a key question unanswered during this interagency process is what to assume about relative risk aversion with regard to high-impact outcomes" (p. 31). Significantly, the study also does not address the most obvious policy implication: If every ton of carbon dioxide emitted is expected to create some amount of damage, then the emission should be taxed at that level to balance that externality.

When governments fail to price climate risk at all, society fails to make appropriate investments in mitigation and the costs of future damages are wastefully magnified. As is well understood, not pricing risk appropriately can lead to disaster. And climate risk is a case in point. When risks are not priced appropriately, investment behavior creates the potential for the catastrophic—and unnecessary—future loss of society's well-being. Unfortunately, it is very difficult for governments to know—and even more difficult to explain to an uninterested public—how to price the unknown risks associated with increasing the levels of greenhouse gases in the atmosphere. The ambiguity in ascertaining the appropriate price, together with such well-known frictions as organized political opposition and the difficulty of enforcing global cooperation, has prevented climate risk from being priced at all in most countries.

Other Complexities

Beyond the need to calibrate risk aversion in a manner at least mildly consistent with the equity risk premium lie other complexities in computing the present value of future damages. As noted earlier, present value is a function of future policies. It represents the beginning of an optimal plan that must respond appropriately in the future to the resolution of uncertainty and to technological change. In order to decide how vigorously to press on the brake today, we must form an optimized plan for dealing with future contingencies—much like a cyclist racing down a mountain who, seeing a dangerous circumstance ahead, recognizes that he is going too fast and must brake appropriately while developing a plan for dealing with the situation.

Still other complexities must be addressed. The most obvious is the tremendous—many would say "fundamental"—uncertainty about the science of *what will happen*. It is not a simple exercise in probability weighting a known distribution of outcomes. Unknown risks doubtless exist.

Investors have relevant experience in making the required assessments, not only in terms of understanding discount rates and optimal planning but also in terms of dealing with uncertainty. When we make investments, we assign probabilities to various uncertain scenarios. Through experience, we learn to appreciate how difficult, but essential, it is to assign probabilities to scenarios that have never been experienced or perhaps even imagined. Investors have experience in pricing unknown risks.

In making an investment, we recognize that how much we should charge for exposure to unknown risks depends on how confident we are in the investment's performance. That degree of confidence will itself depend on how well we understand the investment's environment, how stable it is, and how much experience we have in operating in that environment.

Consider examples of systems that have small probabilities of catastrophic failure. On the one hand, we have such systems as commercial aircraft, in which experts have a very deep understanding of the environment in which they operate and vast experience in operating in that environment. Over time, the appropriate price for exposure to catastrophic failure on commercial aircraft has become quite low. On the other hand, when we push into less familiar territory, such as operating a spacecraft, even the experts have more limited experience and confidence. The appropriate price is higher.

Similarly, catastrophic events in less familiar environments have been observed recently—for example, deepwater oil drilling and operating nuclear reactors. The lack of experience with these kinds of investments has led to catastrophic failures due to unforeseen circumstances. Perhaps not surprisingly, the probabilities of such outcomes are now seen, with the benefit of hindsight, as higher than they were thought to be before the events. Most governments have responded to these catastrophic failures by indicating that they will raise the risk premiums for these types of investments.

This logic applies similarly to climate change, except that society cannot afford to wait to see whether truly catastrophic outcomes will result. Scientists do not understand climate sensitivities all that well. Despite our best efforts, the earth's natural environment remains, along many dimensions, a very uncertain system. For example, there is significant uncertainty about how large the ultimate temperature response will be to any given level of greenhouse gases in the atmosphere; there is even more uncertainty as to how ecosystems—and the human experience—would be affected by severe warming.

Because relevant experiments are extremely difficult to perform, the unknown risks are significant and will likely remain so for a long time. Whether catastrophic risks will be realized can only be determined decades from now, long after the time for taking appropriate preventive actions has passed. Clearly, however, scientists have become increasingly concerned as the evidence has confirmed earlier warnings about risks. Because the known and unknown risks of catastrophic consequences are significant, the risk premium for increased emissions today should reflect those risks. What we do know with virtual certainty is that increasing the level of greenhouse gases in the atmosphere increases the risk of catastrophic outcomes.

Conclusion

When investing in financial markets, investors must think carefully about risk premiums and whether those premiums properly reflect both known and unknown risks. In the case of carbon emissions, the risk premium for increased exposure to unknown risks is clearly not being set appropriately. In the United States and most of the rest of the world, the risk of carbon emissions is not being priced at all. In fact, fossil fuel costs are still being subsidized in the United States and many other countries. Investors—who generally develop long horizons and have extensive experience in dealing with uncertainty and unknown risks—are a natural constituency that should pull together globally to support government action on climate change and to educate the public about the benefits of pricing emissions.

Climate risk is not being priced. It should be priced immediately at a level that appropriately reflects fundamental uncertainty about catastrophic risks and a high level of societal risk aversion.

As President Calderón put it so clearly, it is time to slam on the brakes.

Without attributing any responsibility for the views presented, I thank Kent Daniel, Patrick Bolton, and Frank Ackerman for their efforts in educating me about the economics of greenhouse gas emissions and for significant improvements to this piece.

Notes

1. Frank Ackerman and Elizabeth A. Stanton, "Climate Economics: The State of the Art," Stockholm Environment Institute (30 June 2011). Dr. Ackerman is director of the Climate Economics Group and Dr. Stanton is a senior economist at the Stockholm Environment Institute's U.S. Center at Tufts University.
2. I highly recommend reading the entire summary at www.worldwildlife.org/climate/wwfbinaryitem23166.pdf.
3. U.S. Interagency Working Group on Social Cost of Carbon, "Appendix 15A. Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866" (www1.eere.energy.gov/buildings/appliance_standards/commercial/pdfs/sem_finalrule_appendix15a.pdf).

Citi GPS

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.

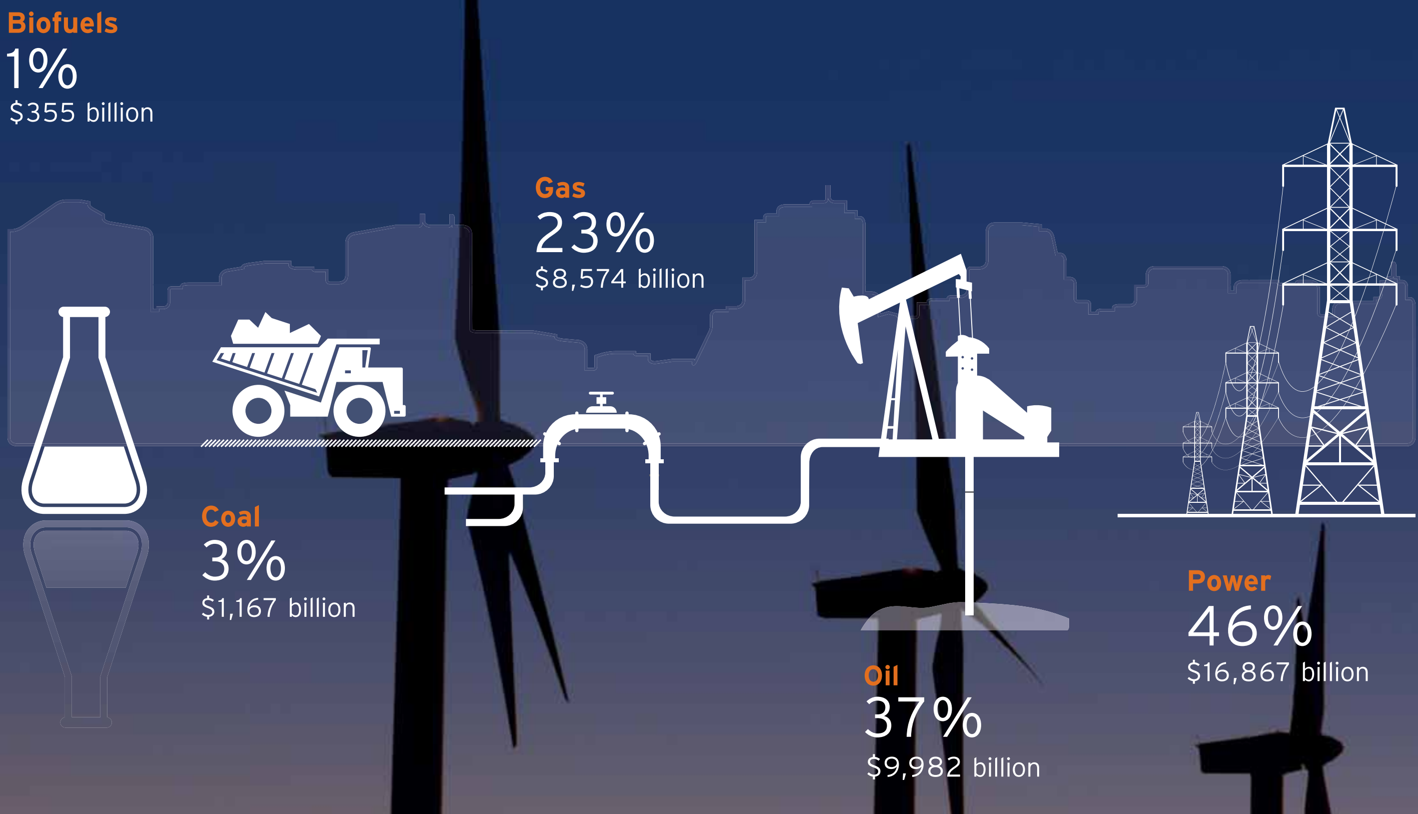
To make the comparison easier, we have focused on the power generation market, as this is by far the largest and fastest growing consumer of primary energy with the highest level of substitution risk. To do this, we have used the levelised cost of electricity (LCOE) concept which allows us to compare 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.



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.

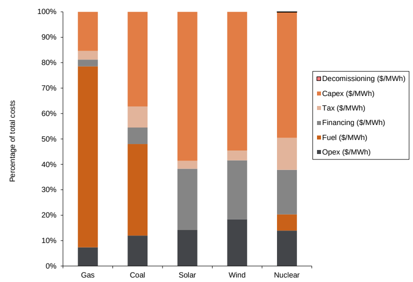
Construction of an integrated energy cost curve…

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.

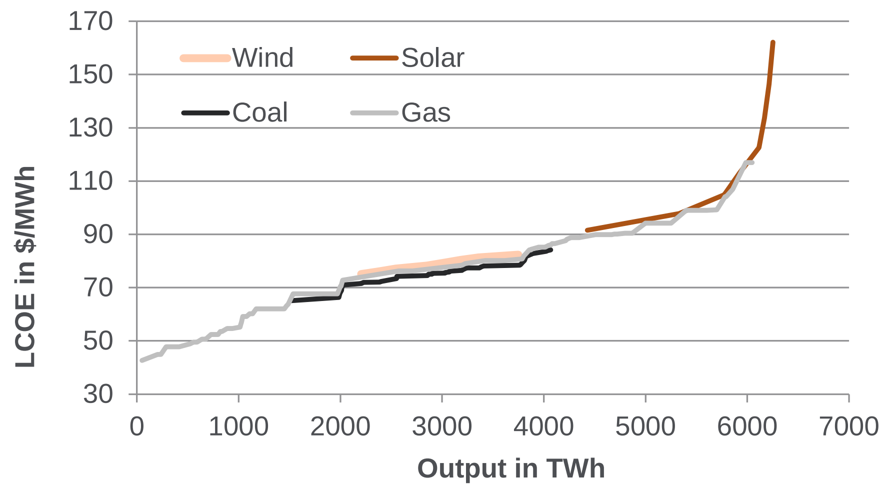
Investments being made now will be subject to relative cost transitions in the energy market which will affect the competitiveness of those fuels or generation technologies, and hence their success or failure. This fuel and technology risk can be witnessed at a customer level by the reluctance of utilities 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

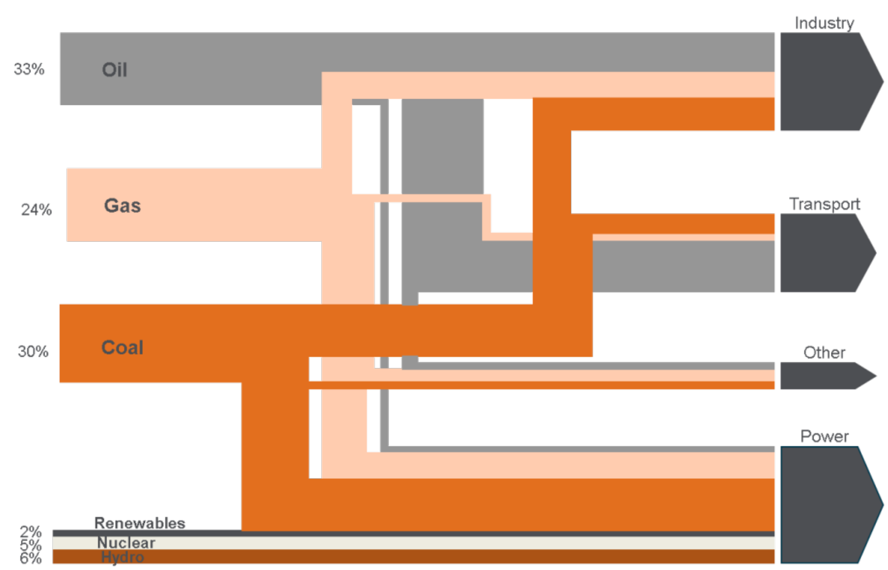
Different geographies are undergoing different changes in their energy mix; contrast the voracious appetite for power in emerging markets largely being met by conventional generation, with the reducing demand in developed markets where existing generation is being cannibalised by renewables. In this 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

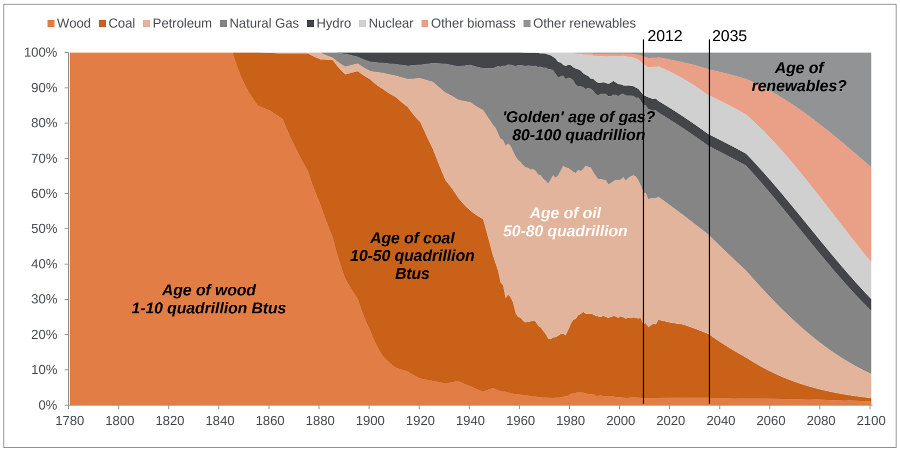
The industry is constantly evolving

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

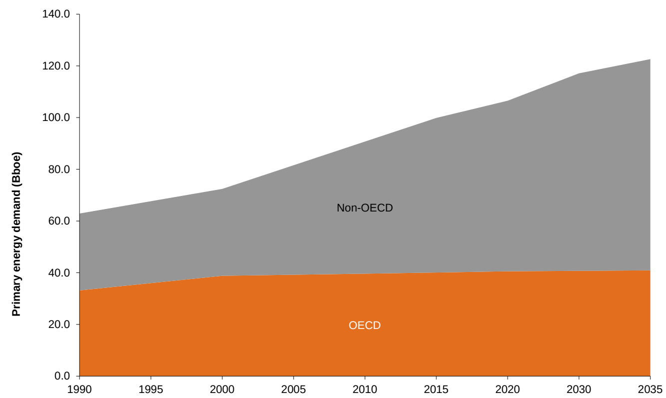
Germany provides a cautionary tale for the world in terms of how quickly the energy mix can change beyond all recognition, and how profound and wide-reaching the implications of that transition can be; this case study is examined in detail within this report.

Developed vs. Emerging markets

Dynamics are different for developed and emerging markets

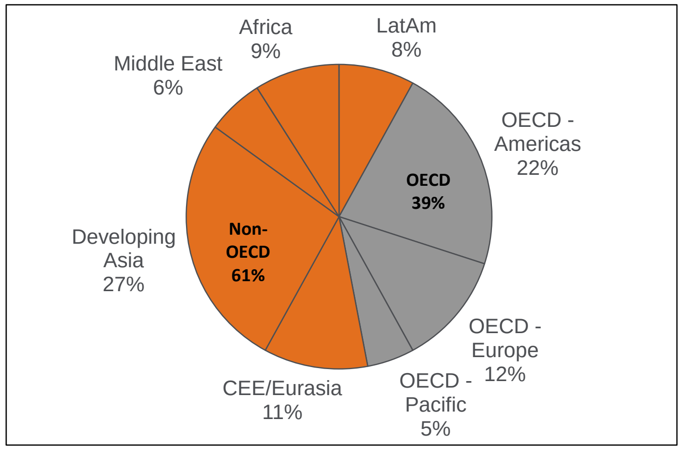
While a fast transition in energy markets might be possible for a highly developed market like Germany, does it provide an applicable template for the world, or only developed markets? Certainly it is worth looking at developed and emerging markets separately as the dynamics are indeed quite different. 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

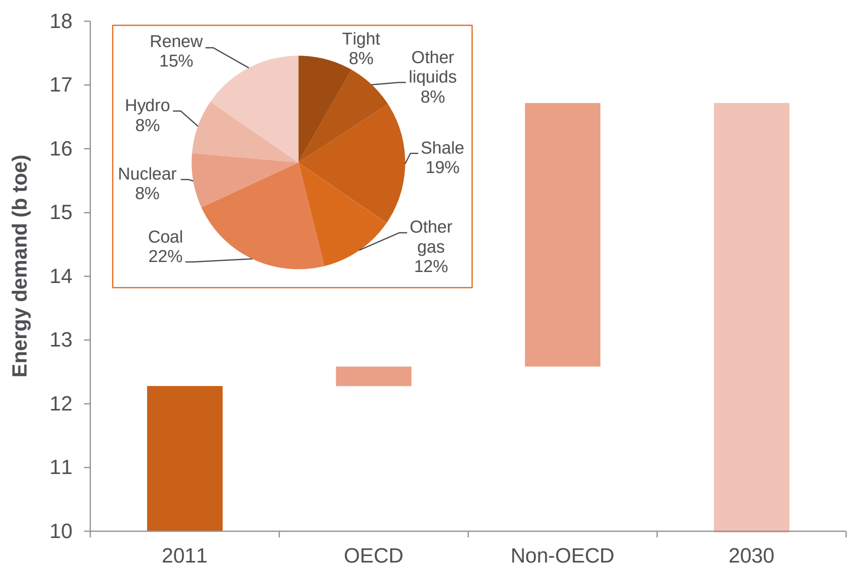


Source: World Energy Outlook 2012 © OECD/ IEA 2012

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



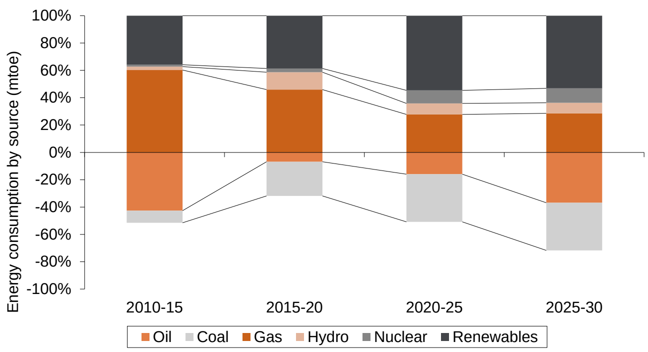
Source: Citi Research; BP Statistical Review of World Energy

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...

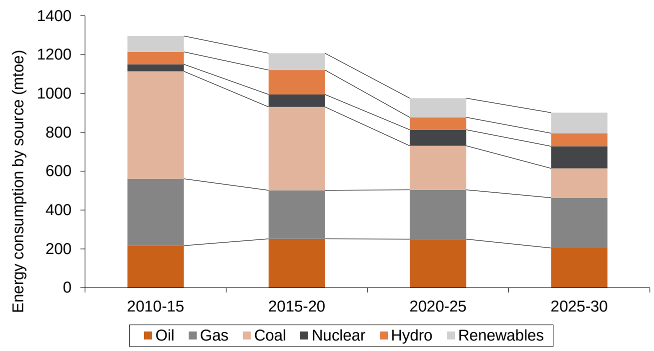
Figure 8 shows that, in developed markets, while net energy consumption will increase, this will consist of a reduction in usage of oil and coal, more than offset by increases in energy consumption from mainly gas and renewables. Conversely, while emerging market demands are much higher (Figure 9), the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



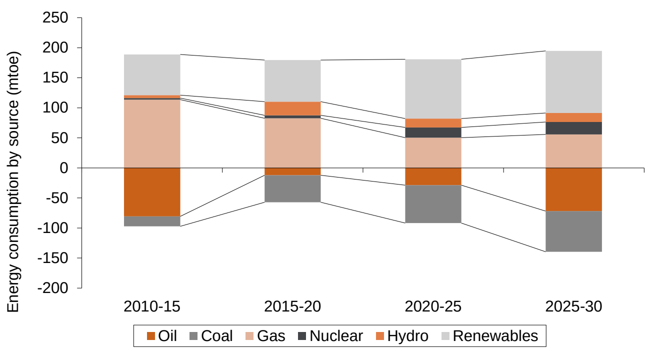
Source: Citi Research; BP Statistical Review of World Energy, IEA

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



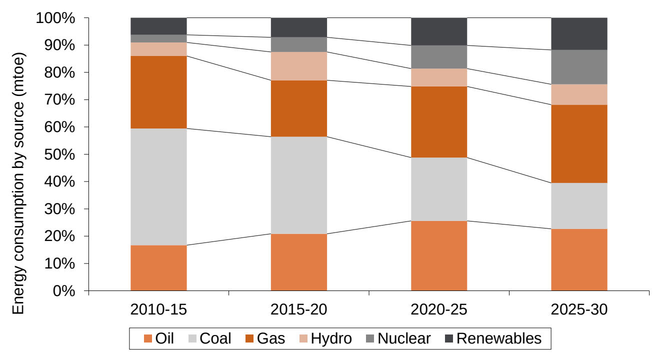
Source: Citi Research; BP Statistical Review of World Energy, IEA

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

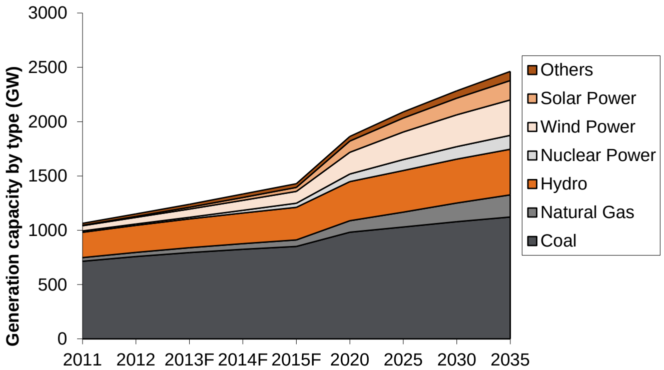
The integrated cost curve analyses incremental energy supply and demand, and hence even small swings are important

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

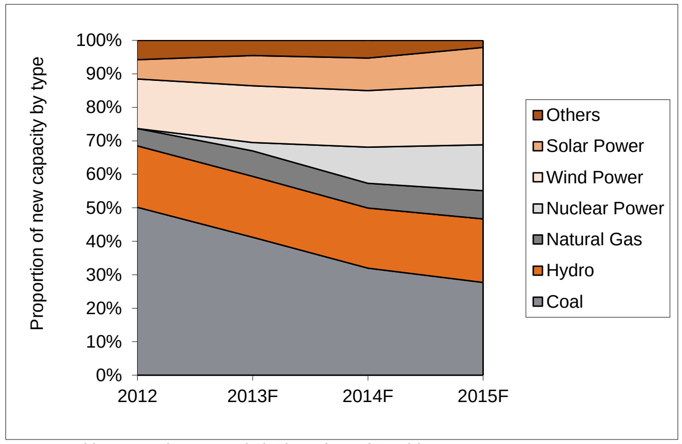
If we look at this issue in more detail for China, the most important growth market in terms of electricity generation capacity, the same picture is borne out. While demand for all energy sources is growing, (Figure 12), the decreasing importance of coal is notable, as is the increasing proportion of 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

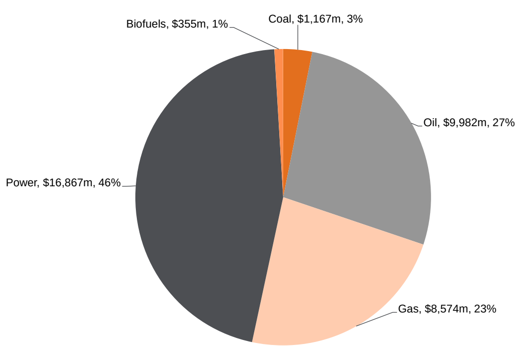


Source: Citi Research; BP Statistical Review of World Energy, IEA

Investment by energy source

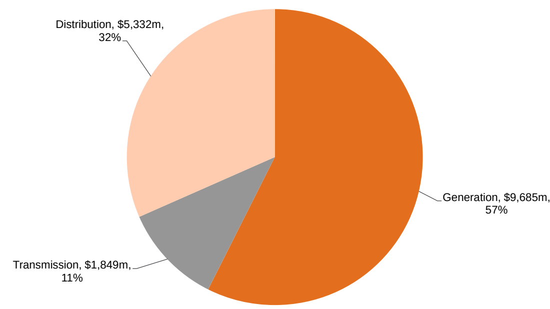
This investment of $37 trillion in primary energy forecast by the IEA out to 2035 can be broken down into requirements by energy use, and by fuel type.

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



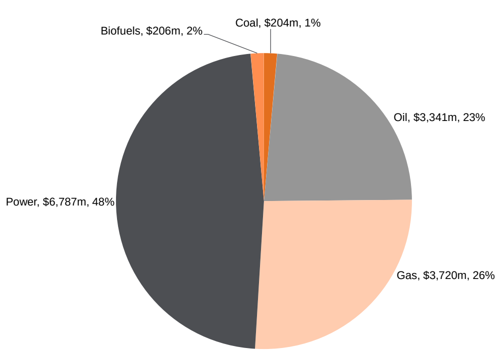
Source: World Energy Outlook 2012 © OECD/ IEA 2012

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



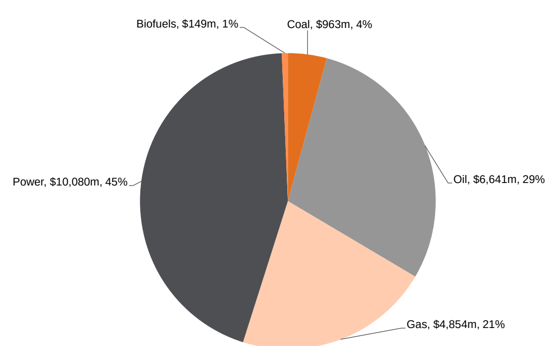
Source: World Energy Outlook 2012 © OECD/ IEA 2012

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



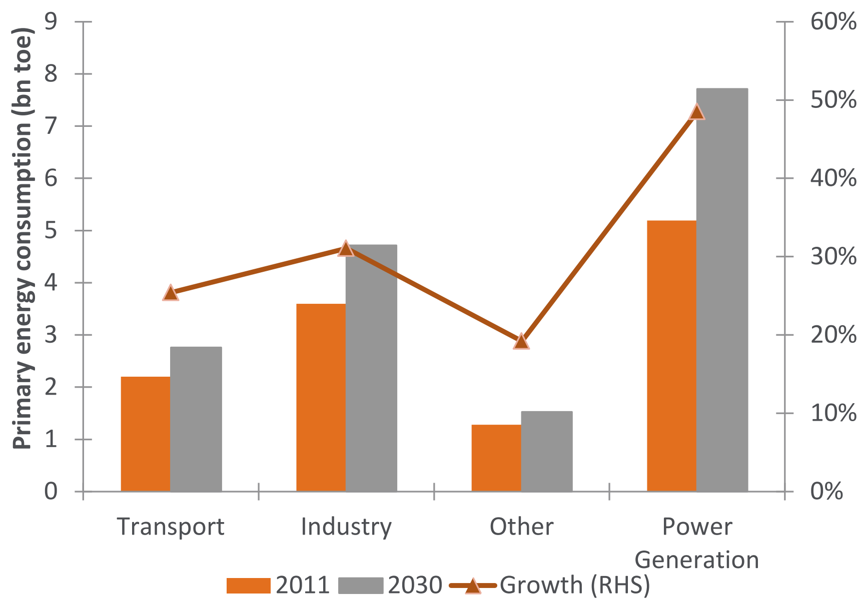
Source: World Energy Outlook 2012© OECD/ IEA 2012

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).

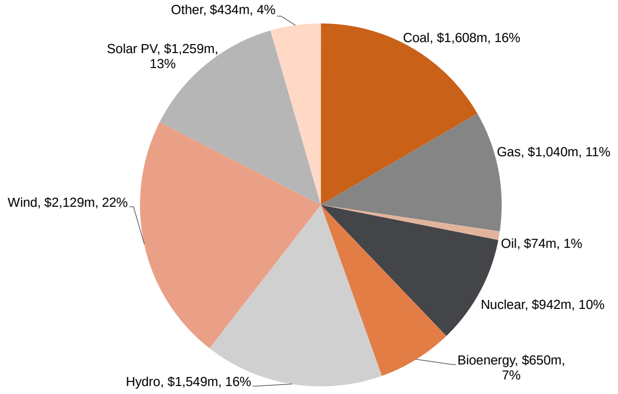
Moreover, it is worth stressing once again that the integrated cost curve analysis that is the crux of this note relates to **incremental** energy supply coming on between now and 2020, and hence although some technologies may be relatively small now, it is their applicability as a ‘choice’ which affects 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.

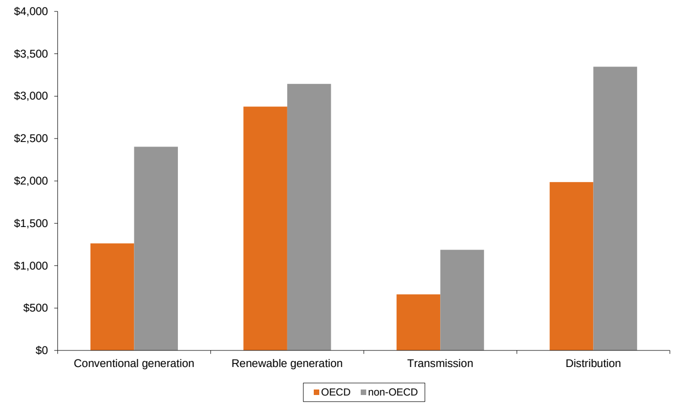
Figure 19 examines the split of the $9.7 trillion global investment in power generation by technology highlighted earlier.

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

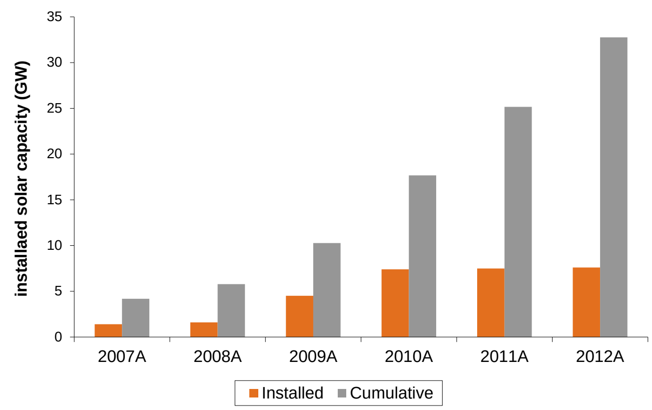
However, while these might be viewed as an impediment to installing new technologies, we would observe that in a majority of cases these costs are not borne by the developer of the renewable asset, but either centrally or indirectly by customers by means of a 'renewables surcharge' and hence are not 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

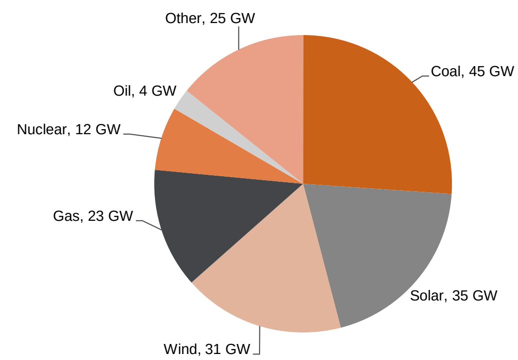
In just 6 years, there has been a fundamental shift in the Germany electricity generation mix, as highlighted in Figure 21 and Figure 22.

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

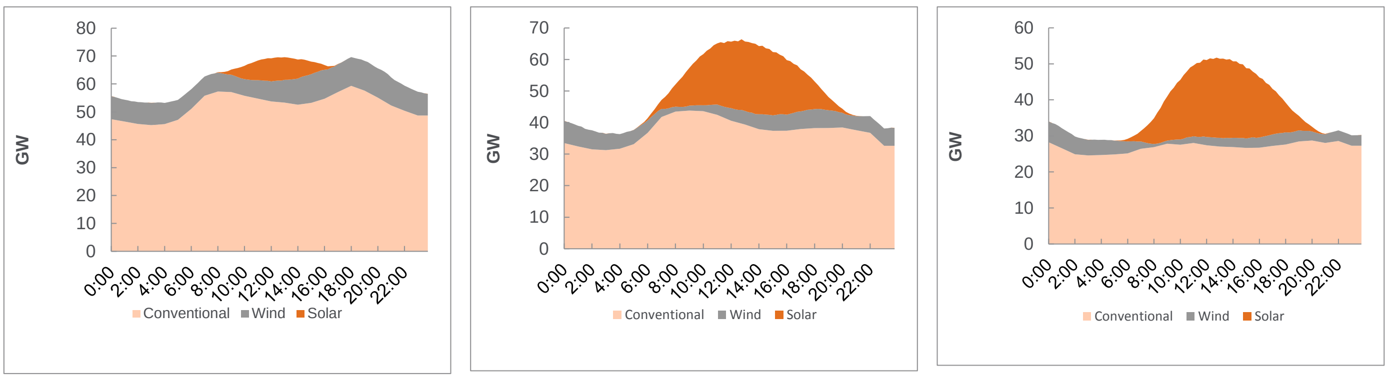
While solar generates only a relatively small amount of units of energy per unit of capacity (a low 'load factor' or utilisation rate of about 10-15%), it is the time of day at which it generates those units which causes the biggest headache for utilities.

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

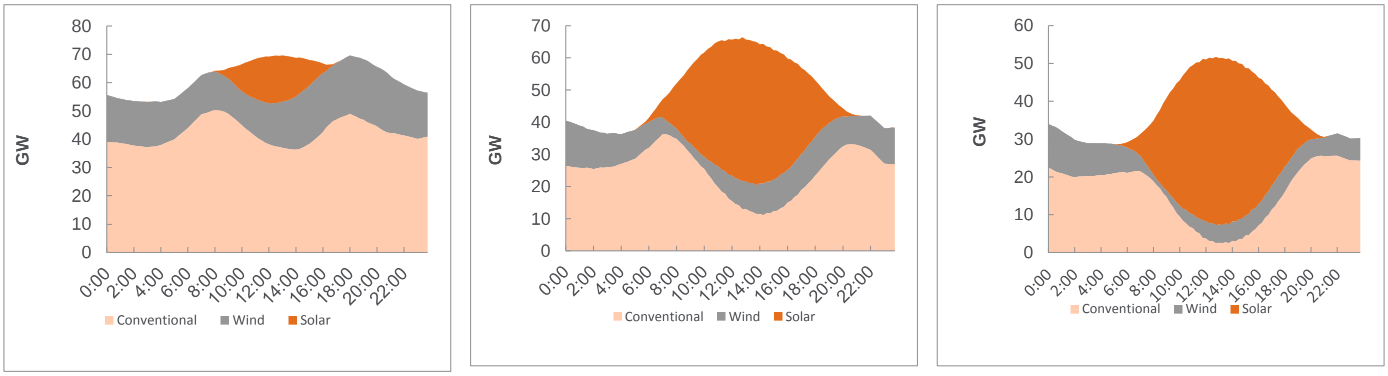
This effect of solar providing all of summer peak demand has resulted in some gas power plants in Germany running in 2012 for less than 10 days, with resulting profit warnings from their utility owners who as recently as two years ago saw renewables as 'niche' technologies.

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.

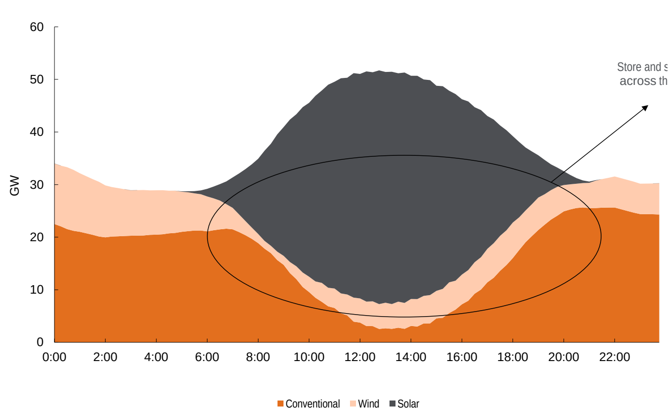
Germany has introduced a pilot storage subsidy scheme, much as it did with solar

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

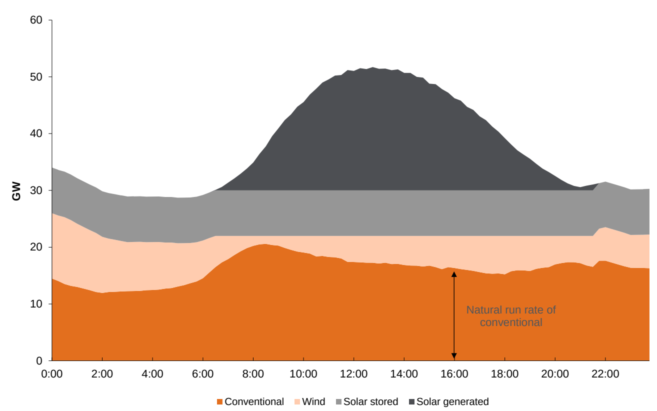
If, as we suspect, storage is the next solar boom and becomes broadly adopted in markets such as Germany, the electricity load curves could once again change dramatically causing more uncertainty for utilities and more disruption to fuel markets. With baseload still operating flat out, the surplus solar 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

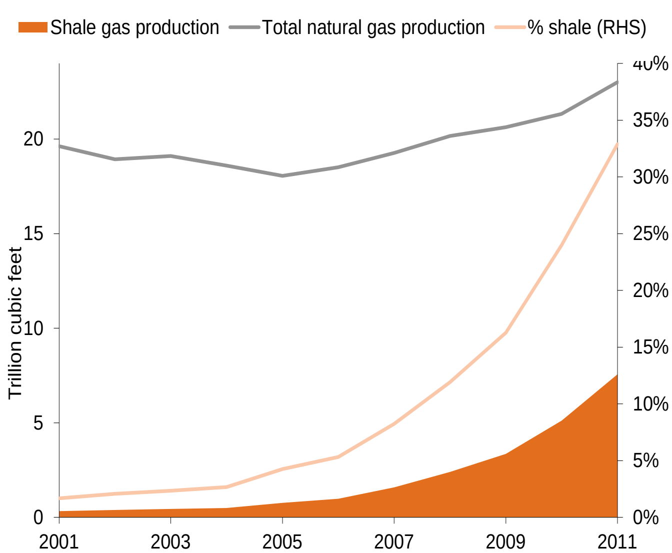
The advent of shale gas has nothing short of revolutionised the global energy mix, and the economic fortunes of those countries lucky enough to have been blessed with extensive reserves — while penalising those less fortunate. It has changed the shape and levels of the oil & gas cost curve, with a corresponding 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.

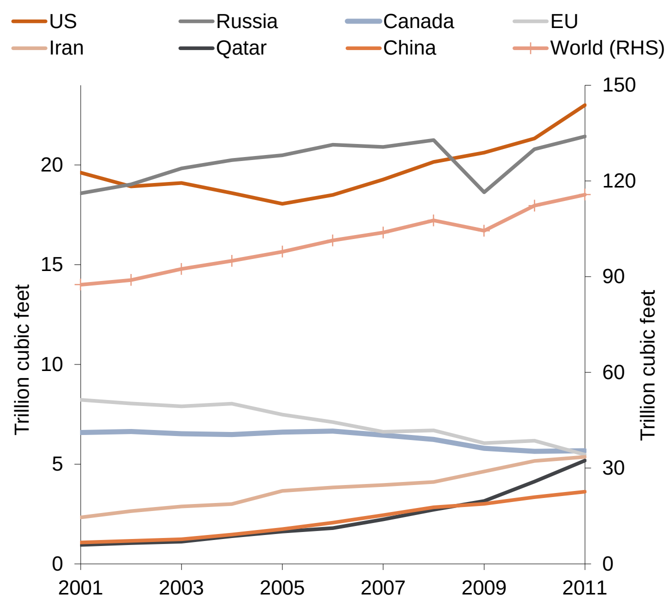
The exploitation of shale gas has led to a renaissance in total U.S. natural gas production since 2005. Reversing a decade-long decline, production has risen from a low of ~18 tcf in 2006 to a record high of ~23 tcf in 2011.

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…

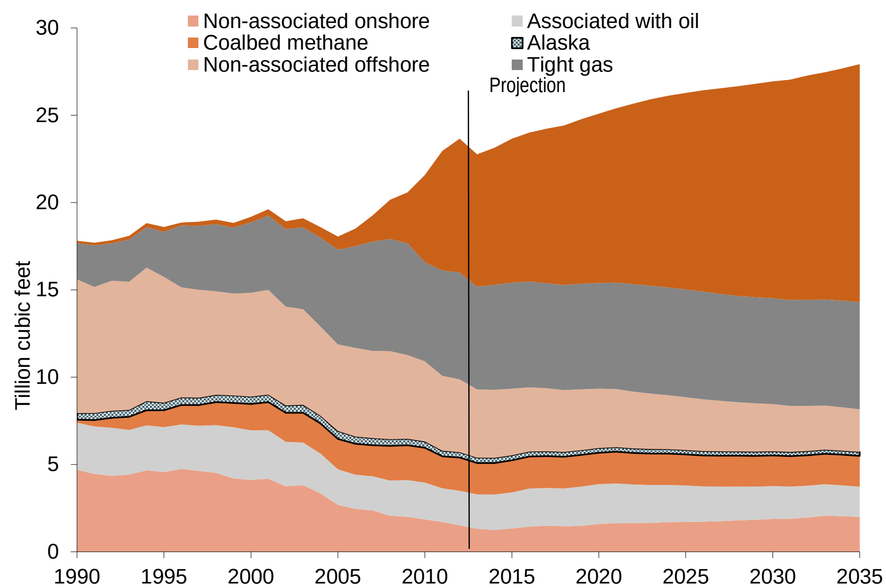
U.S. shale gas production is expected to continue its growth in the medium term, reaching 14 tcf by 2035 according to the US Energy Information Administration (EIA). This would position shale gas as the dominant source of natural gas in the U.S., accounting for ~50% of the total U.S. natural gas supply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

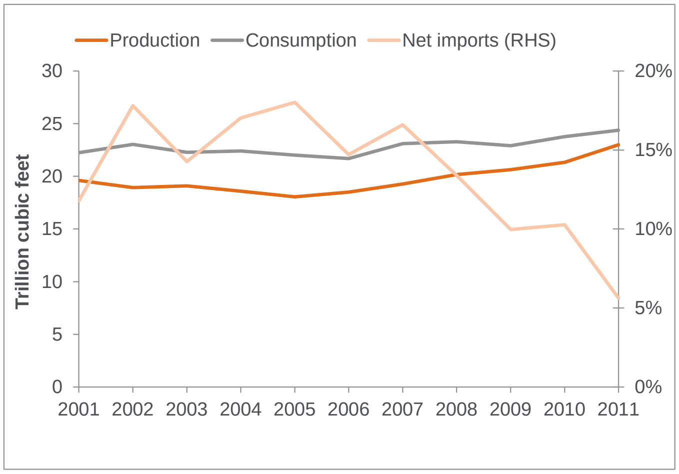
…and is likely to transform the U.S. from a net importer of natural gas to a net exporter of natural gas…

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.

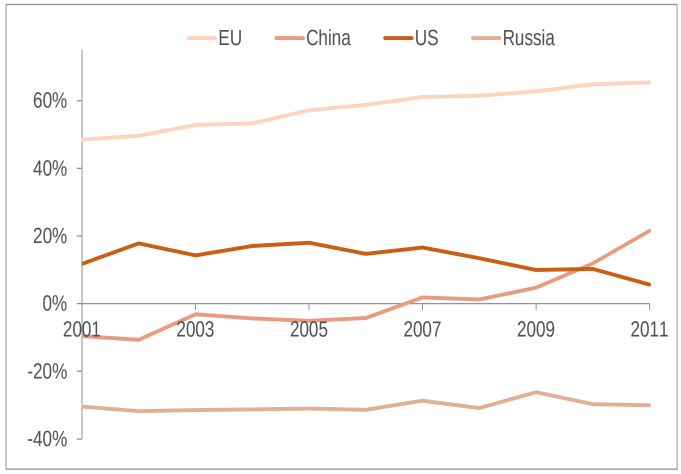
The fall in U.S. natural gas imports contrasts with the fortunes of the EU, which now imports over 60% of its natural gas, and China, which in the last 10 years has shifted from being a net exporter of natural gas, to being a large net importer (Figure 32).

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.

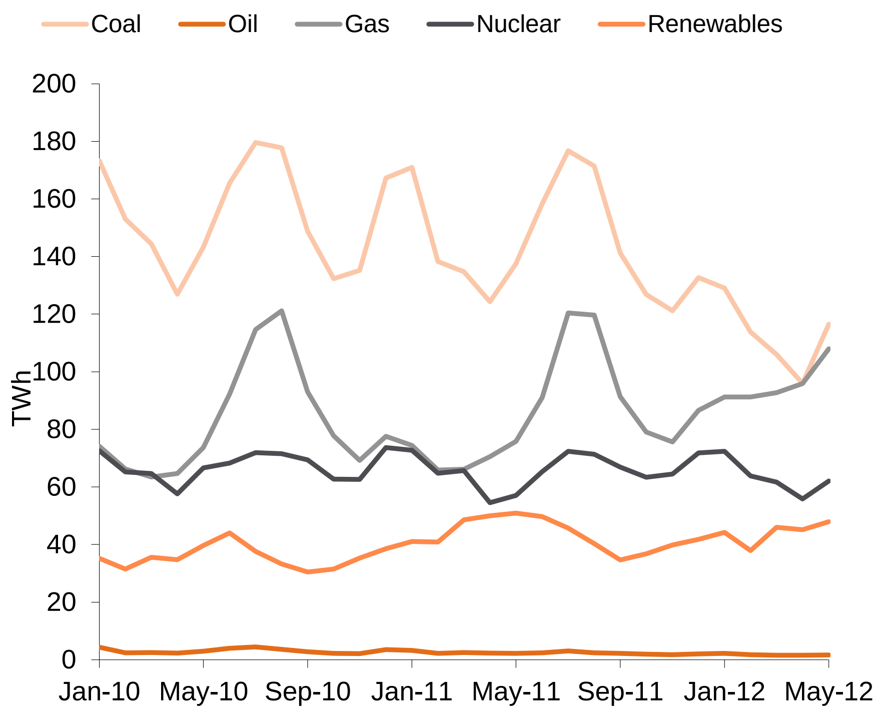
What are spark, dark, and quark spreads?

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

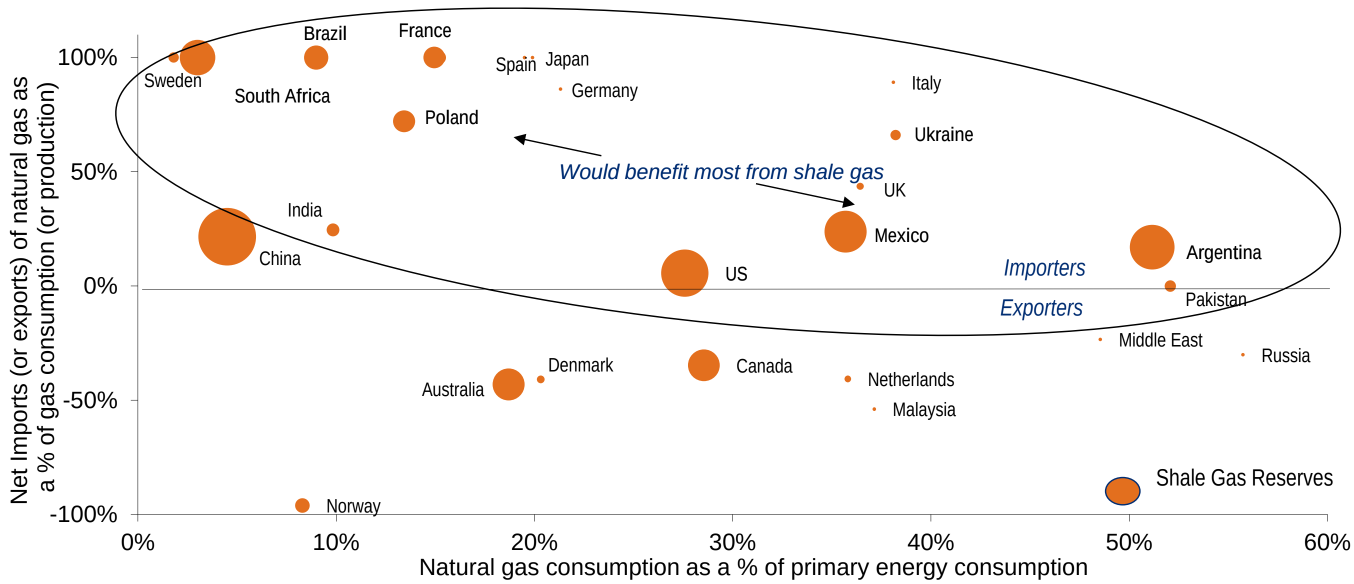
By contrast, the big potential losers are those that do *not* appear to have significant shale gas reserves and which fit into the two above categories: 1) Germany, Japan, Italy, Spain and to some extent the UK, or; 2) Malaysia, Trinidad & Tobago, Egypt and Uzbekistan. Note, however, that this would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

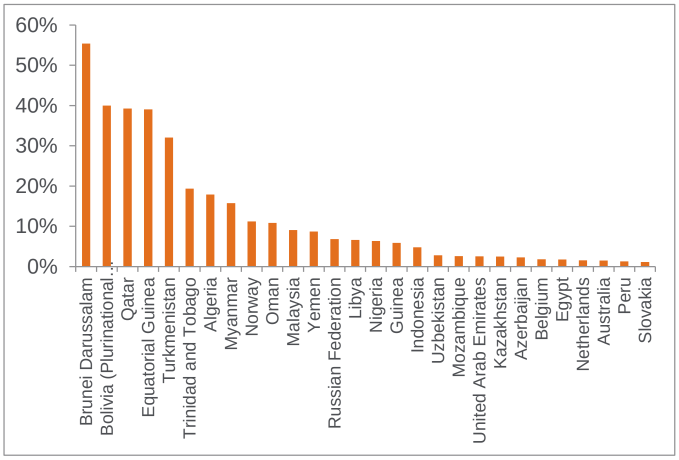
Figure 34. Location of shale gas versus natural gas consumption and imports



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

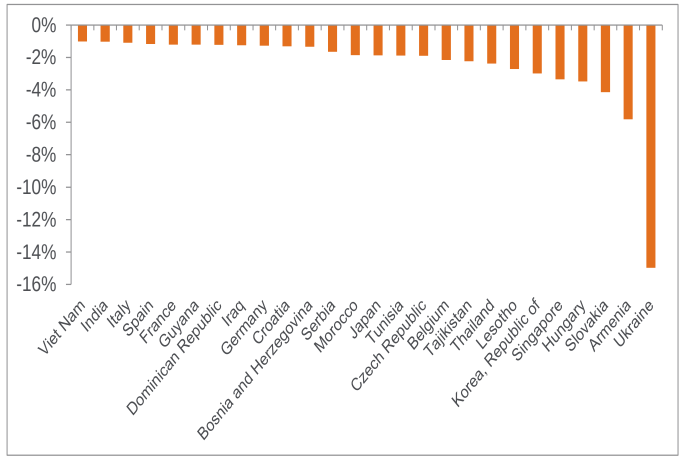
Figure 35 and Figure 36 show these exports or imports as a percentage of GDP, to give a sense of the scale of economic important to the country.

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

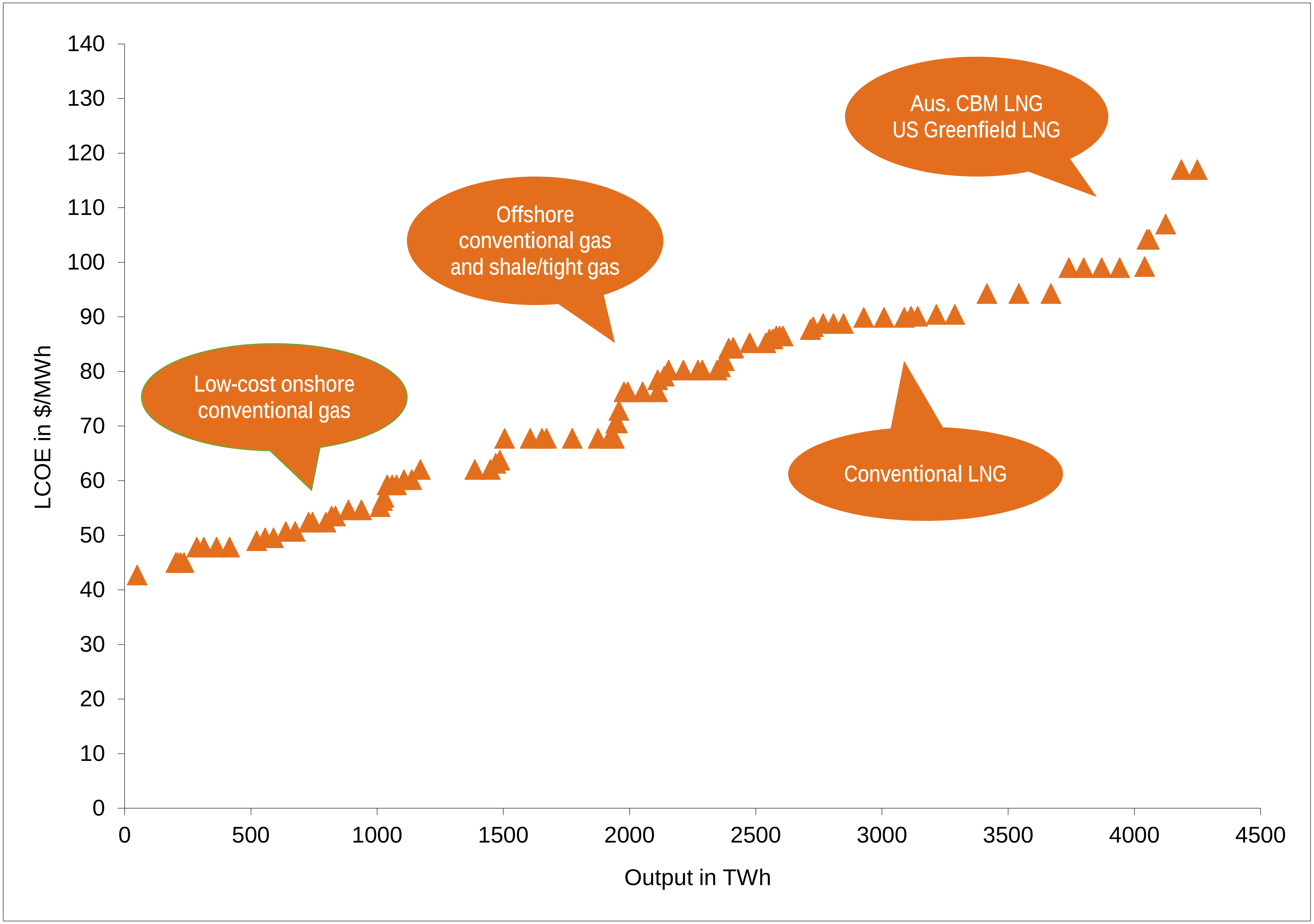


Source: Citi Research, BP, IMF

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.

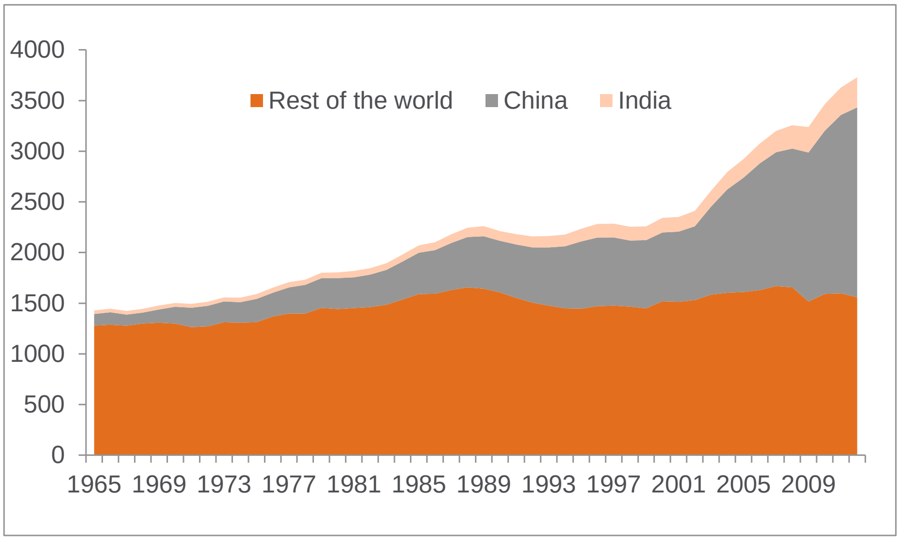
The impact of U.S. Henry Hub gas pricing has already been transmitted globally through three ways:

- 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



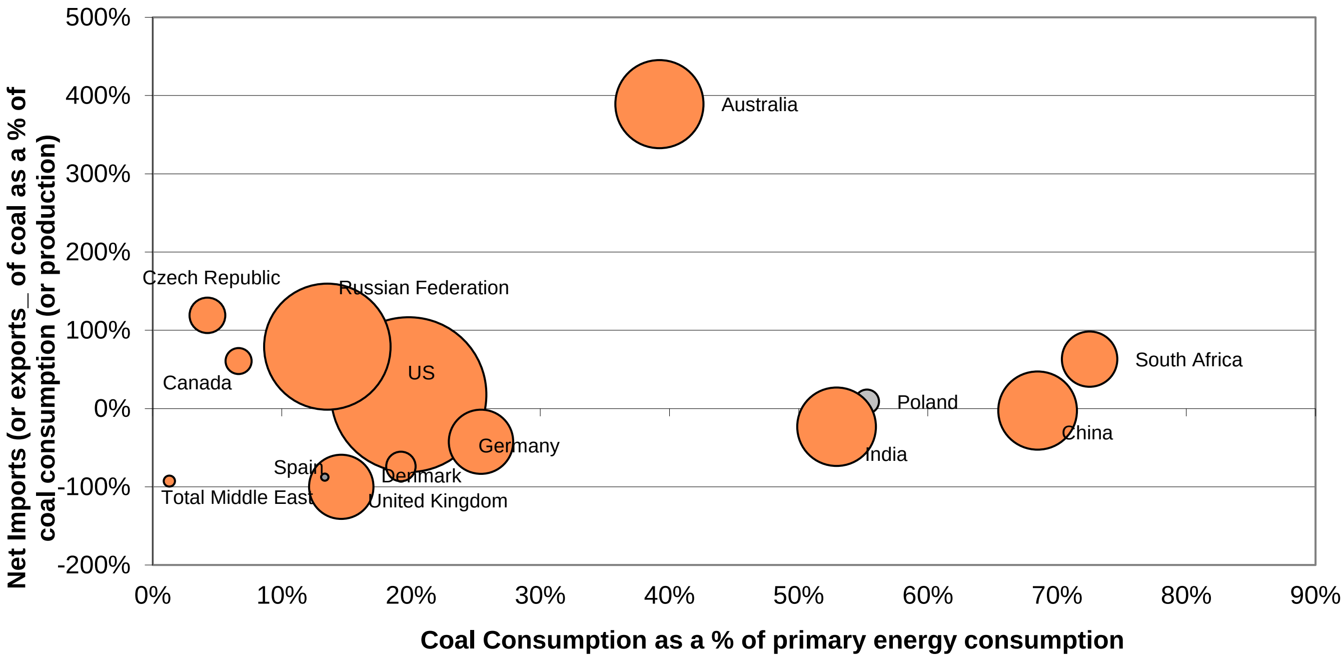
Source: Citi Research, IEA, IEA, BP Statistical Review of World Energy

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.

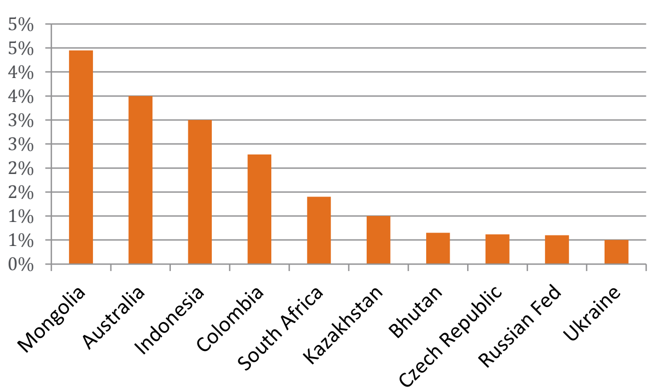
Figure 39. Location of coal reserves versus coal consumption and imports



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

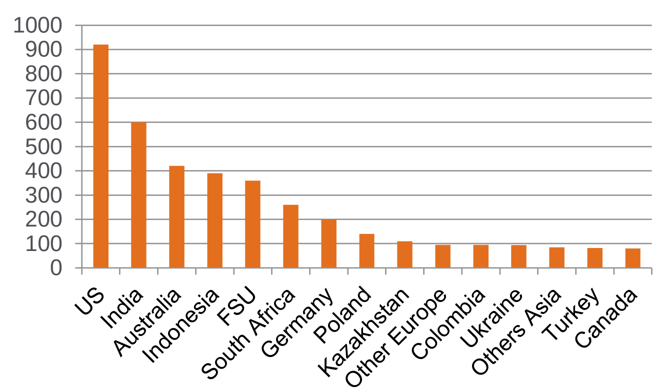
While Figure 39 puts the dependence on imports and the importance of consumption in a relative context (and is designed to be viewed in conjunction with Figure 34 for gas), the absolute export figures are given in Figure 41.

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.

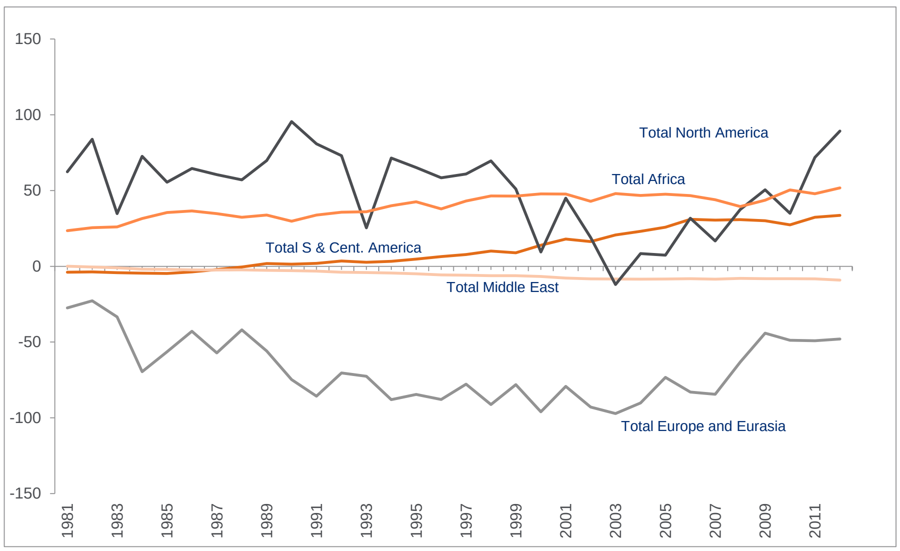
European demand has also fallen due to stagnant demand from key coal importing countries such as the UK, Germany and France and a pick up from Russian exports.

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

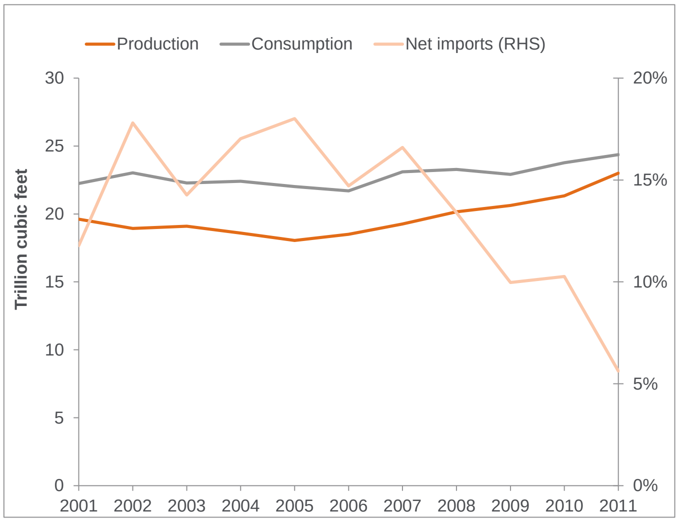


Source: BP Statistical Review of World Energy, Citi Research

Shale has impacted the coal markets

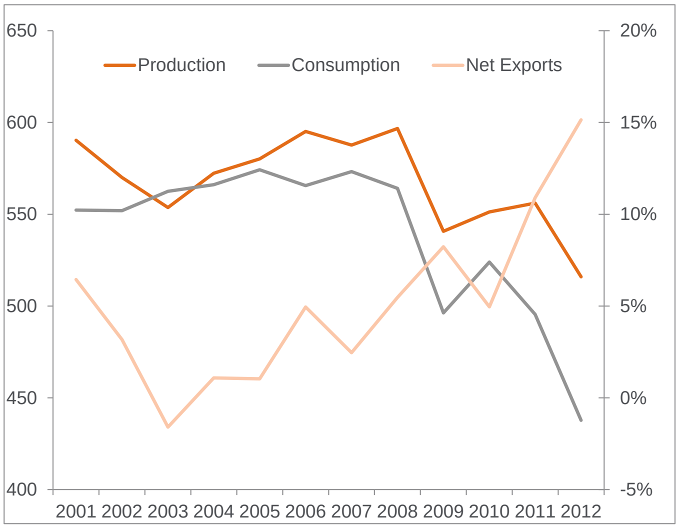
The U.S. shale gas revolution not only sparked a major shift change in the Atlantic region which has had ripple effects in the Pacific region. The U.S. flipped from being a net importer of both natural gas and coal, to being an exporter of coal. The U.S. imported around 2% of their coal need in 2003,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

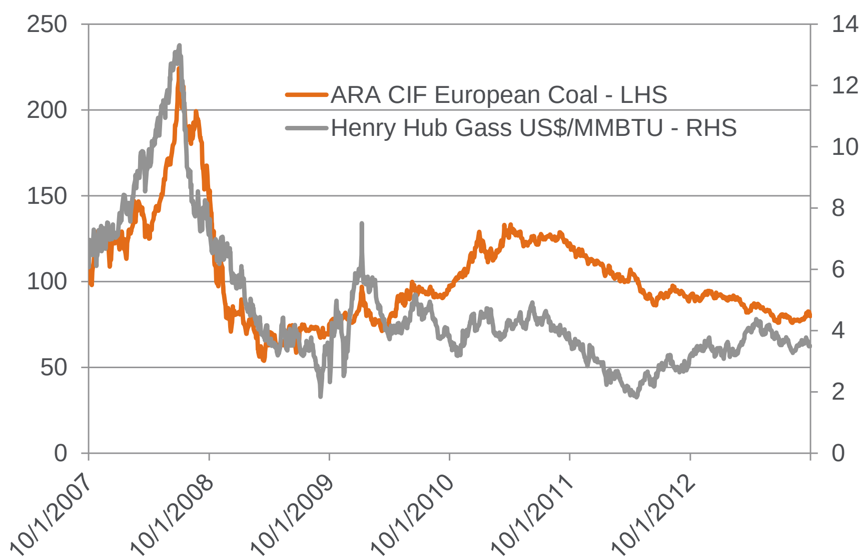


Source: BP Statistical Review of World Energy, Citi Research

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



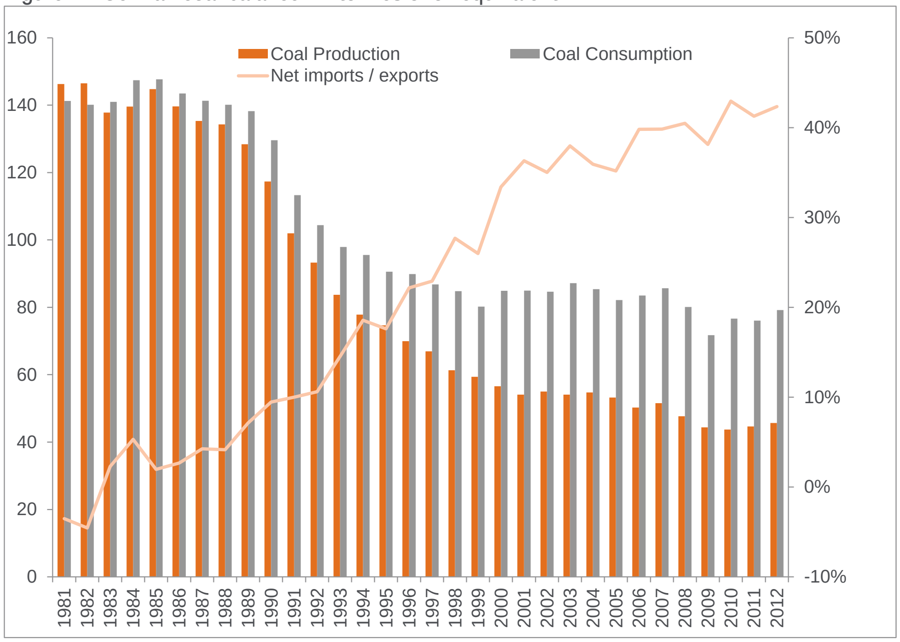
Source: Citi Research

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

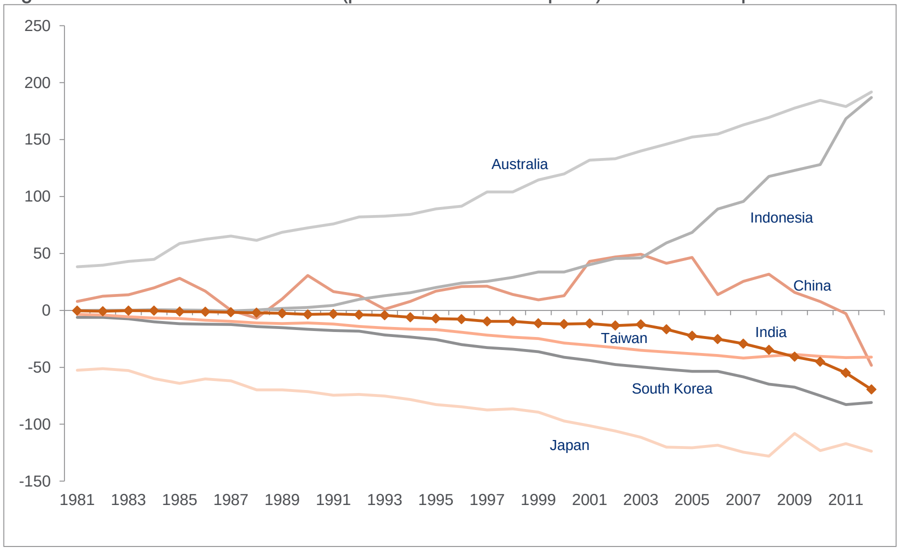


Source: Citi Research

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

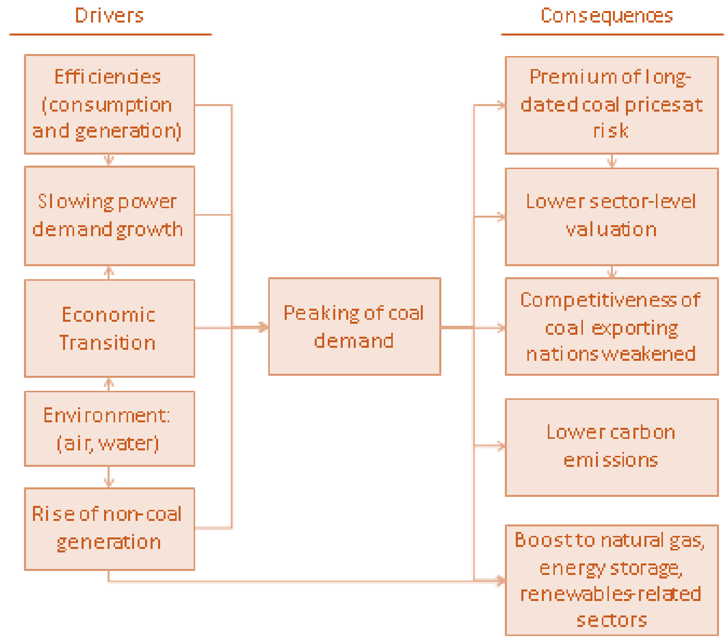
For a more detailed discussion of this topic see our recent report: The Unimaginable: Peak Coal in China - Effects of possible peaking of coal demand in China could ripple across global coal trade, producers and carbon emissions.

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.

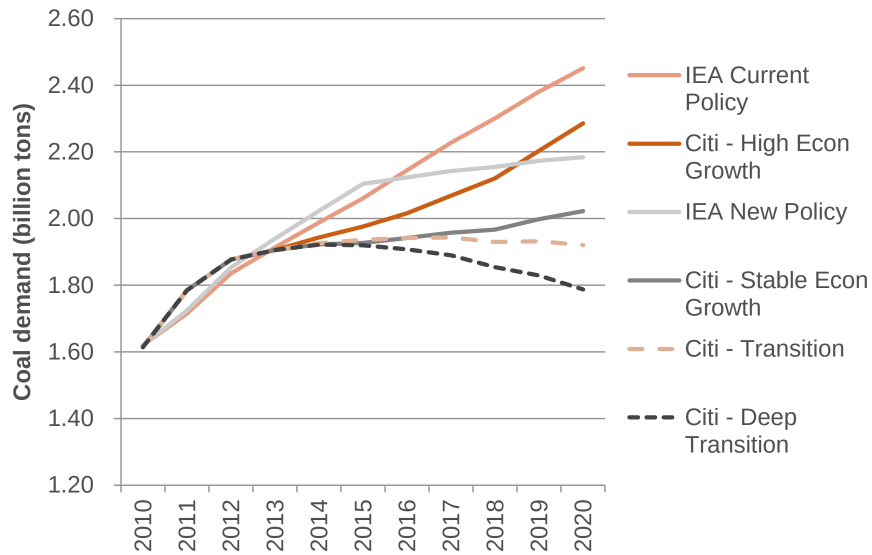
In a sign that demonstrates the commitment by the Central Government to reduce pollution, the Ministry of Environmental Protection temporarily suspended approvals on environmental impact assessments for new construction or expansion of refineries, thereby halting construction. The two largest refiners 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.

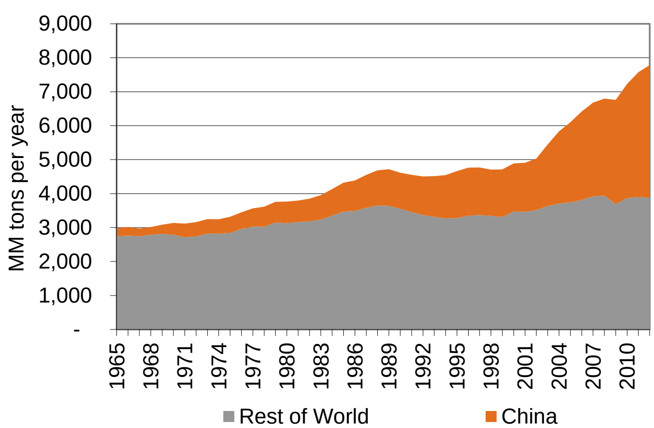
Figure 50. China power sector coal demand scenarios – adjusting expectations lower



Source: IEA, Citi Research

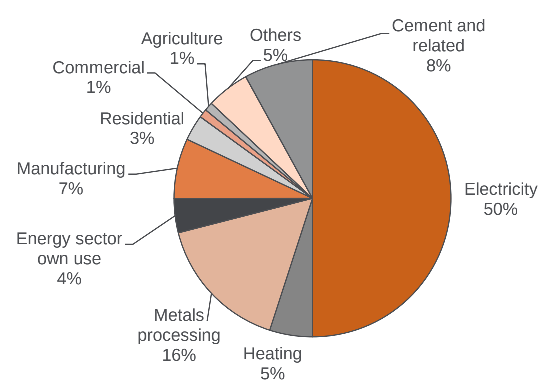
Changes in the generation fuel mix in China would have substantial impact on global fuels market and emissions, as coal demand for electricity generation in China accounts for nearly 25% of world consumption. Besides, electricity demand in China is widely-used as a reliable gauge of the health of the 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

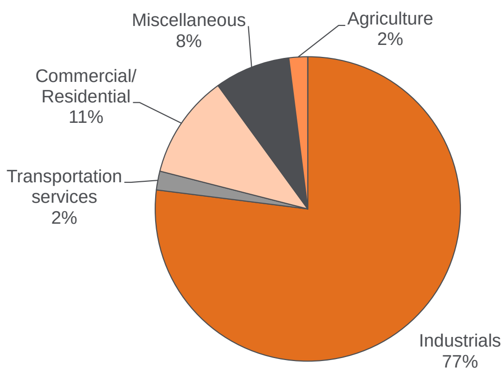
Figure 52. Coal demand for power generation accounts for about 50% of total consumption in China



Source: IEA, Citi Research

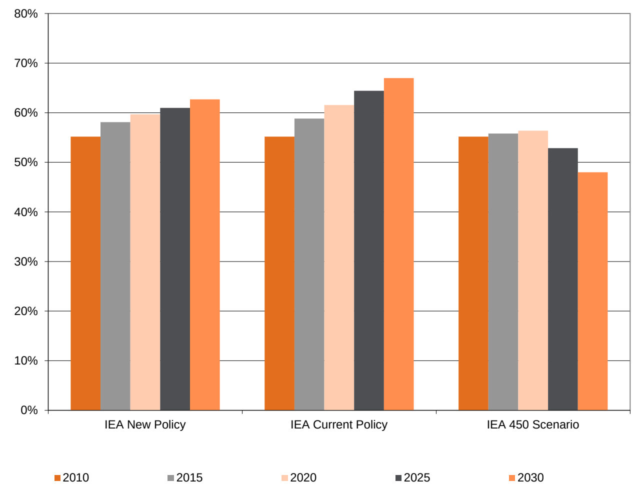
Electricity demand can also be a powerful indicator of non-electricity coal demand. As over three-quarters of electricity demand come from industrials and related sectors, a slowdown in total power demand growth should imply a deceleration in the industrial segment of the economy. With the industrial 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

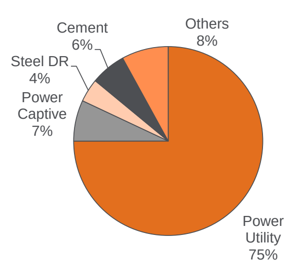
India: A slower growth market

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

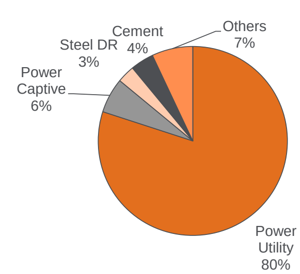
We expect India's total thermal coal supply to grow at a ~6.5% compound annual growth rate (CAGR) in fiscal 2012-15E, slower than a 15% CAGR in underlying demand. To balance supply and demand, imports would have to grow 44% annually. However, forecasting India's imports is complex due to 1) the price 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

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

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.

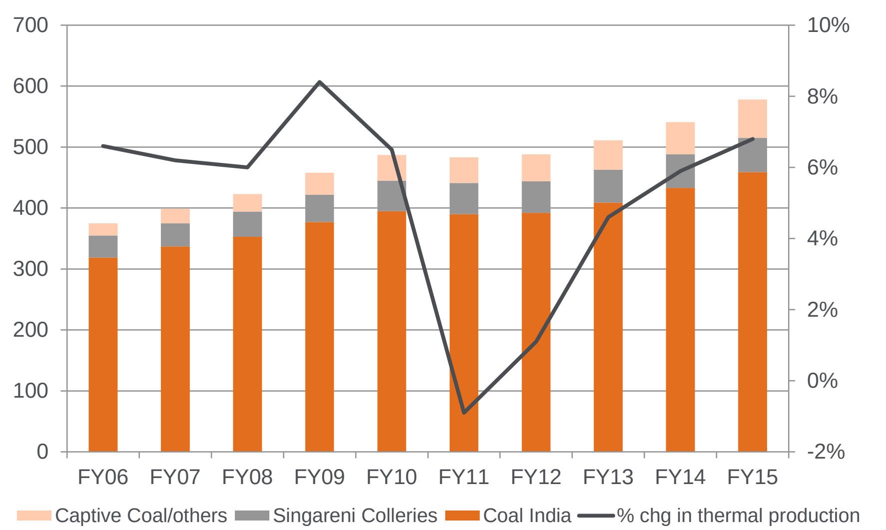
Figure 58. Thermal coal demand/ supply table

(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

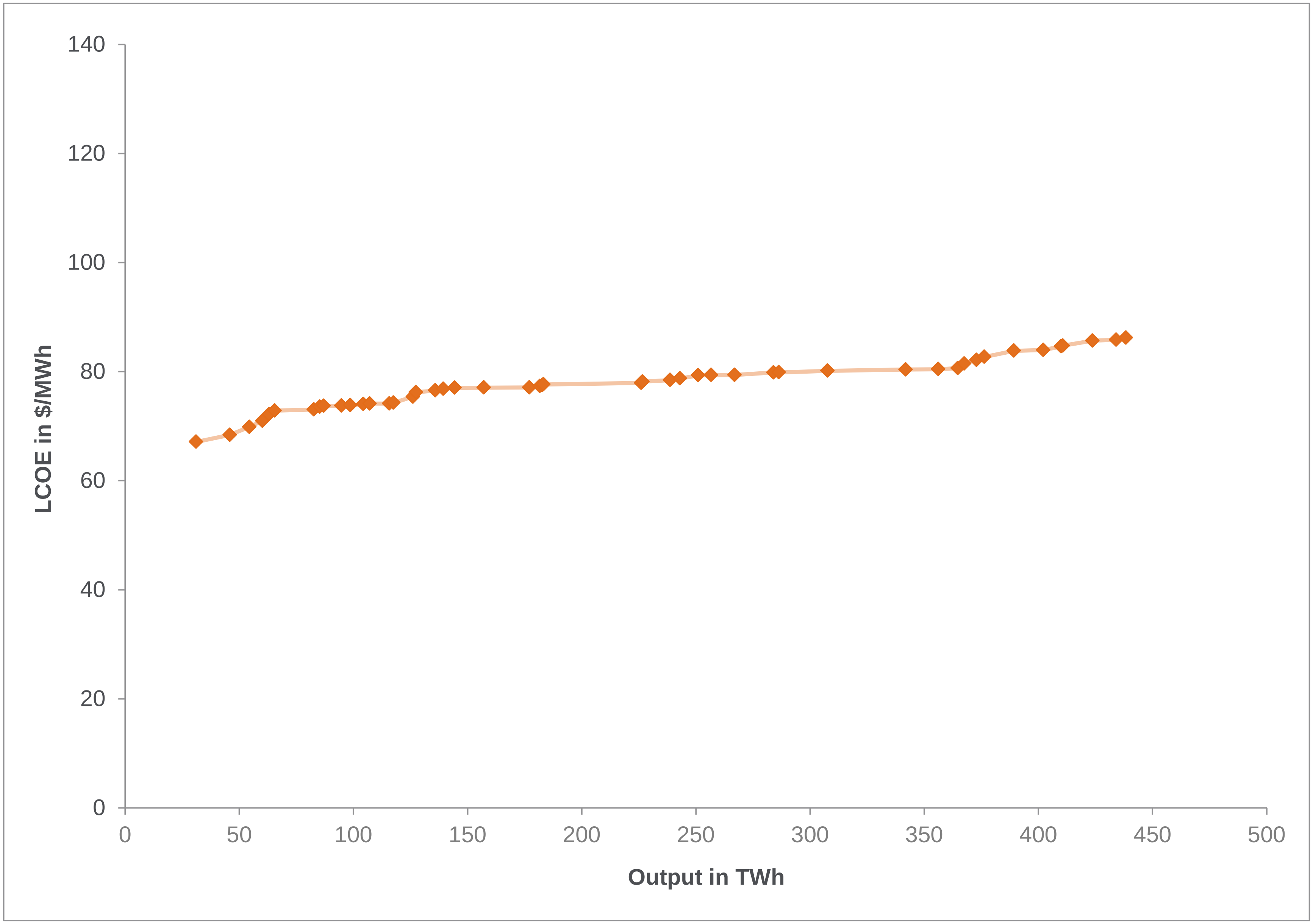
The global coal cost curve

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

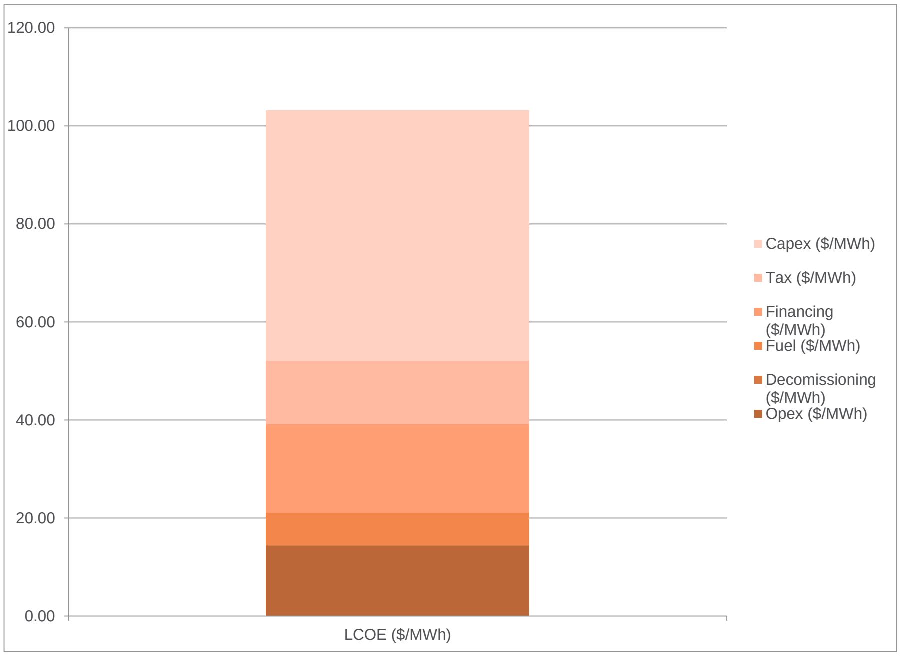
Nuclear: Not suited to competitive uncertainty

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

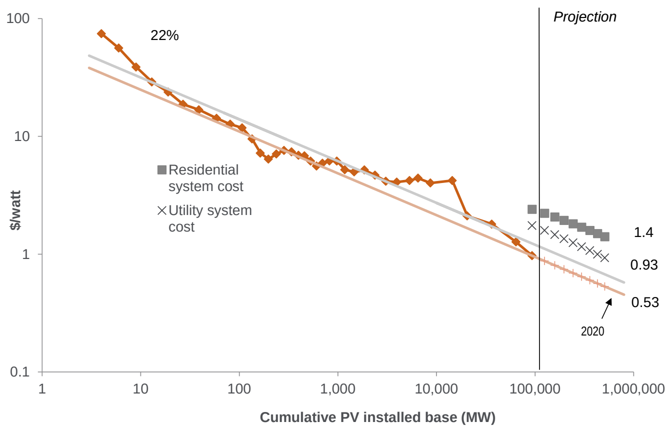
While nuclear technology has evolved over time this is harder to plot, as well as considering the fact that there is scope for a paradigm shift should other methods of nuclear generation such as fusion ever be harnessed/become commercially viable. The capital cost of nuclear build has actually risen 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

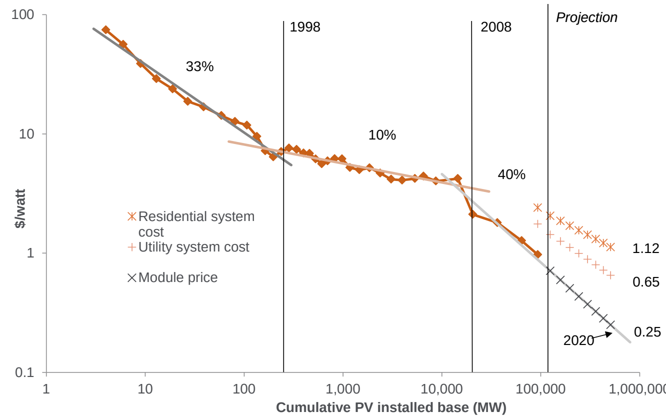
The rate at which the price of solar panels has reduced has exceeded all expectations, resulting in cost parity being achieved in certain areas much more quickly; the key point about the future is that these fast 'learning rates' are likely to continue, meaning that the technology just keeps getting 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.

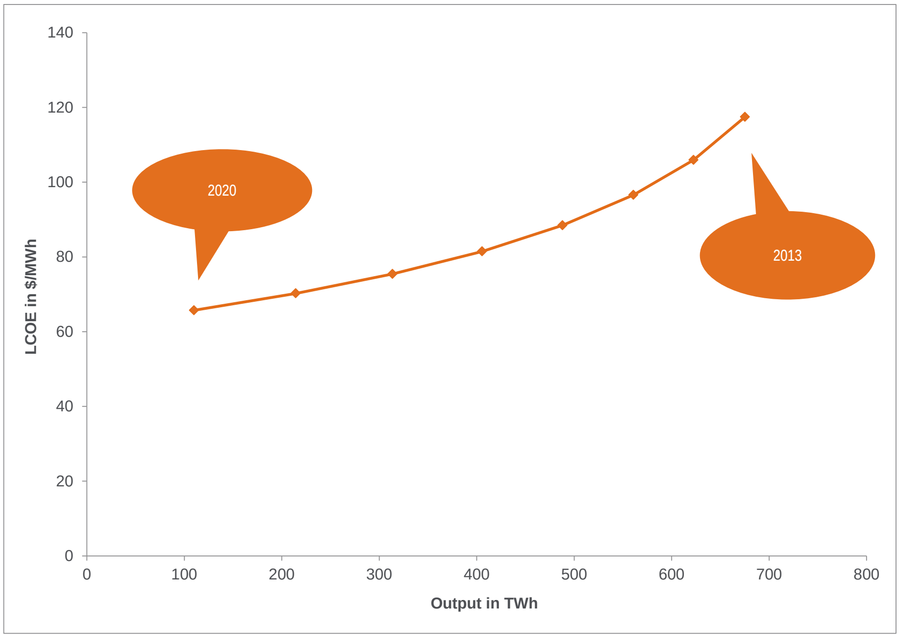
Solar financing is also evolving with the advent of solar leasing and green bonds

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



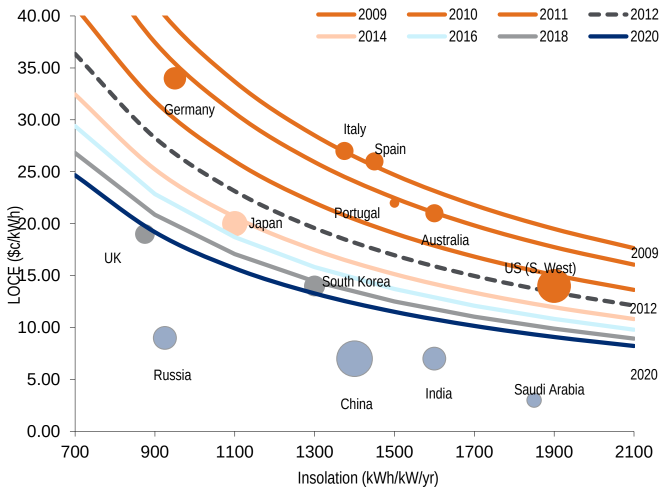
Source: Citi Research

The relative economics of generation

Already cost competitive in an increasing number of regions

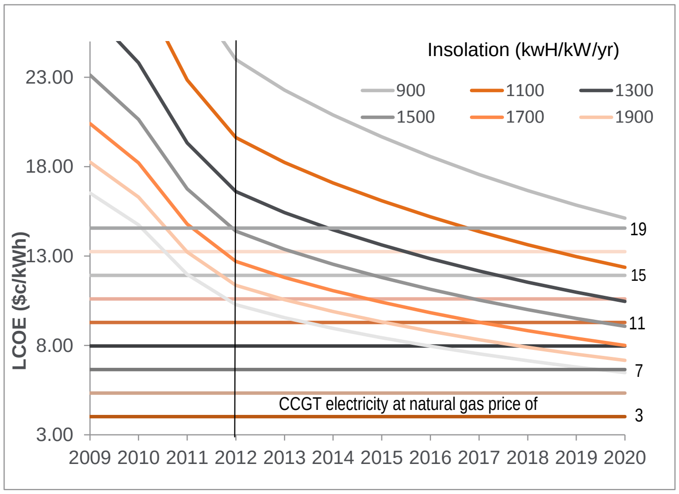
These dramatic cost reductions mean that solar is already competitive in many regions at a domestic level (Figure 66), and even at utility scale vs. combined cycle gas turbines (CCGT's) in some higher priced markets (Figure 67). As discussed, the fact that solar keeps getting cheaper as technology advances 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

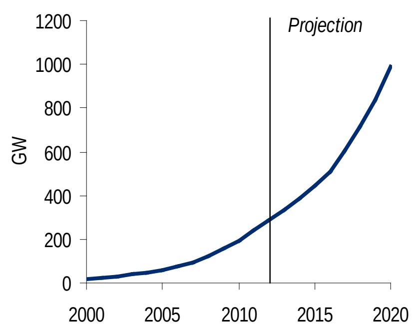
While wind technology is evolving, it is doing so much more slowly than solar. However, it has the advantages of offering more 'base-load'-like characteristics in running more of the time, and perhaps most importantly is lower cost than solar, allowing the technology to compete against conventional generation 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.

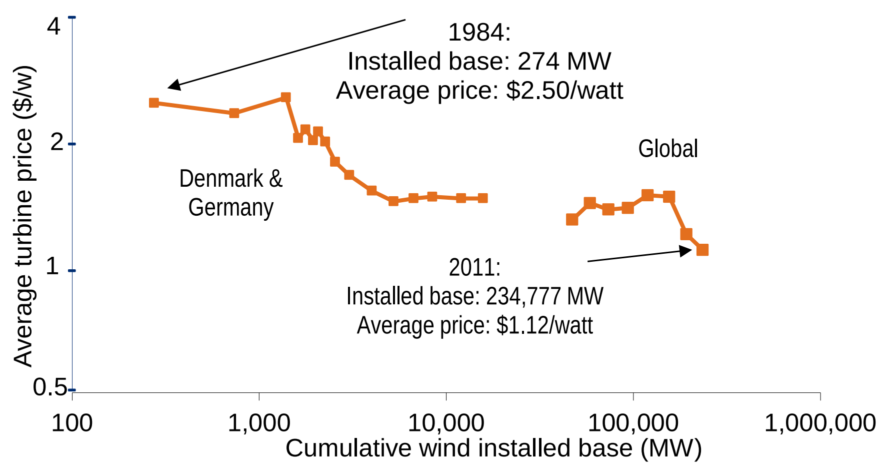
This decline is borne out by the price data, which pre-1999 covers Danish and German manufacturers and post-2004 covers global manufacturers (Figure 69).

Figure 68. Forecast for future cumulative wind installed base



Source: Citi Research

Figure 69. Historical average turbine costs against cumulative installed capacity

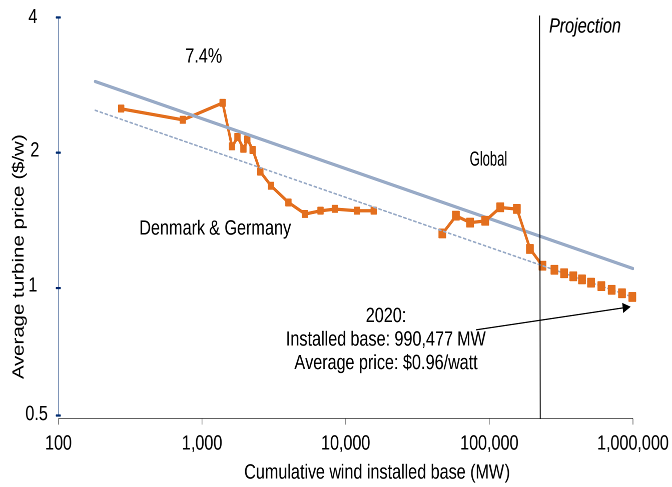


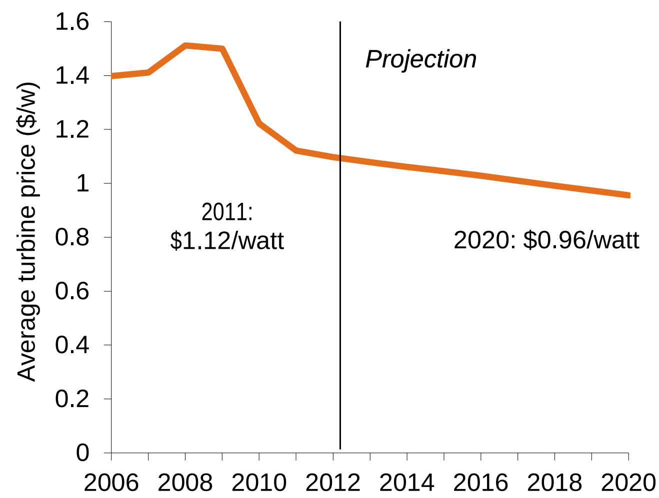
Source: Bloomberg New Energy Finance, Citi Research

…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





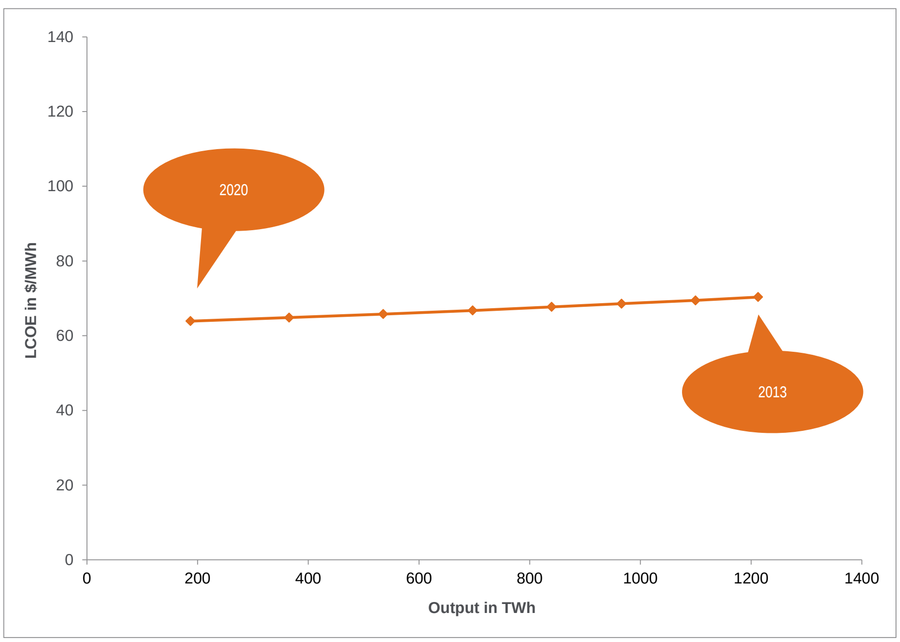
Source: Bloomberg New Energy Finance, Citi Research

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

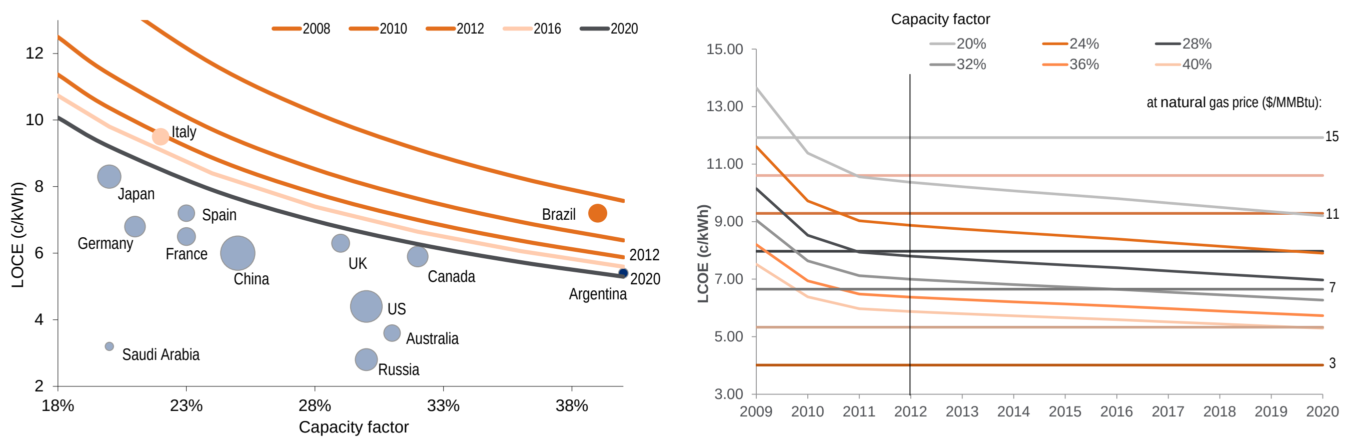
Wind power is significantly cheaper than solar power, and in most countries wind delivers electricity at a far lower cost than the residential electricity price. However, even at the more relevant utility scale, wind power is already competitive with gas-fired power in many regions. In the best U.S. 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



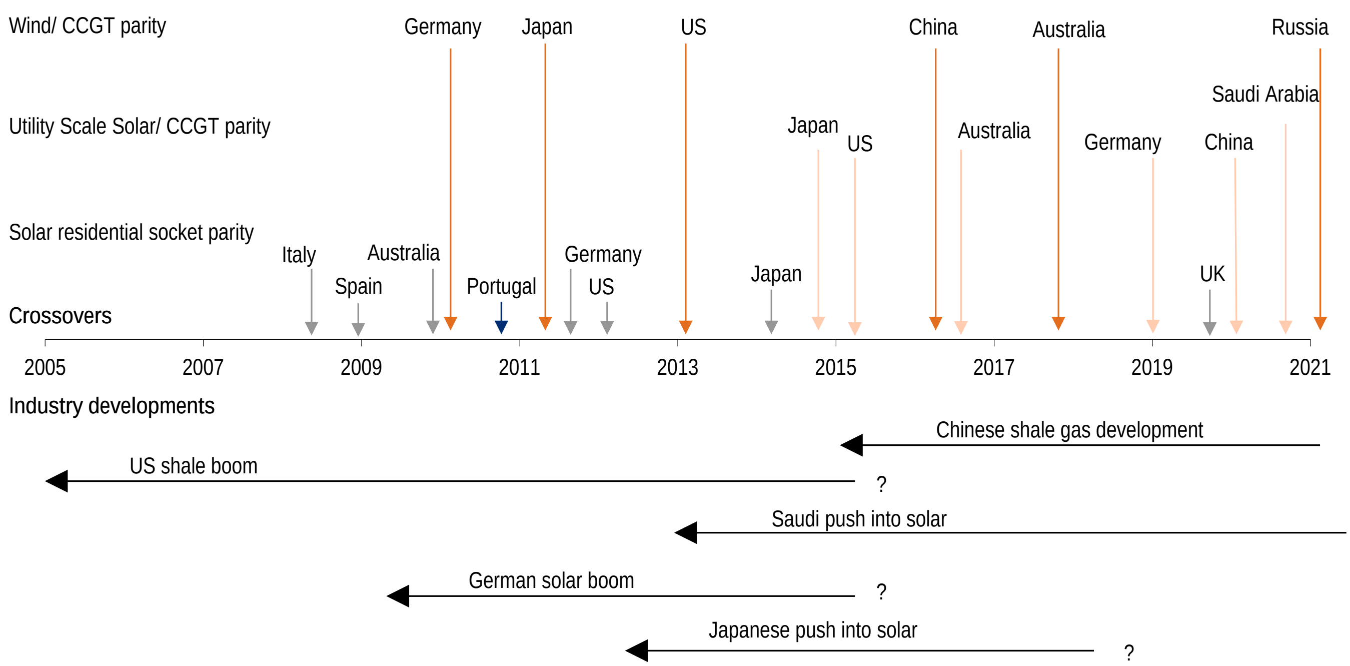
Source: Citi Research

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

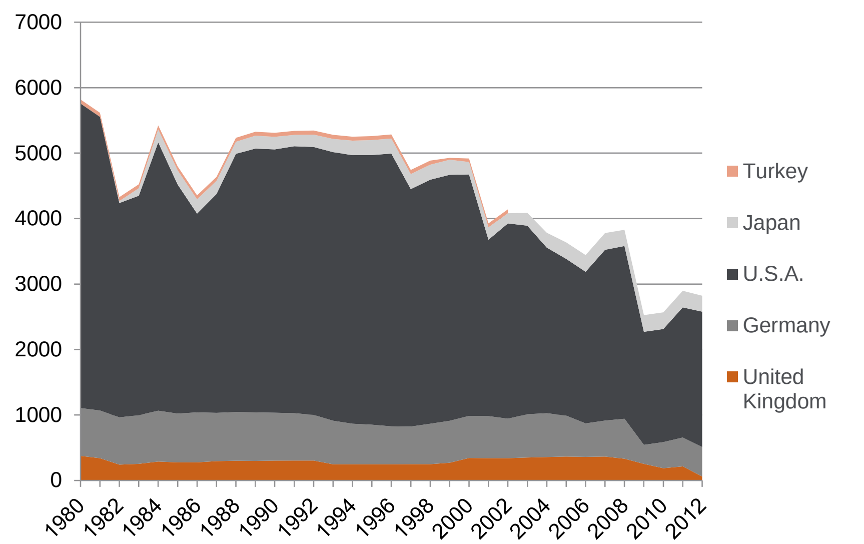
The ability to transport energy has a large bearing on the ability to arbitrage different energy sources, and in turn impacts the costs and efficiencies achievable. Infrastructure is a key determinant in this process be it a pipeline, LNG facility or port into the power generation location, alongside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

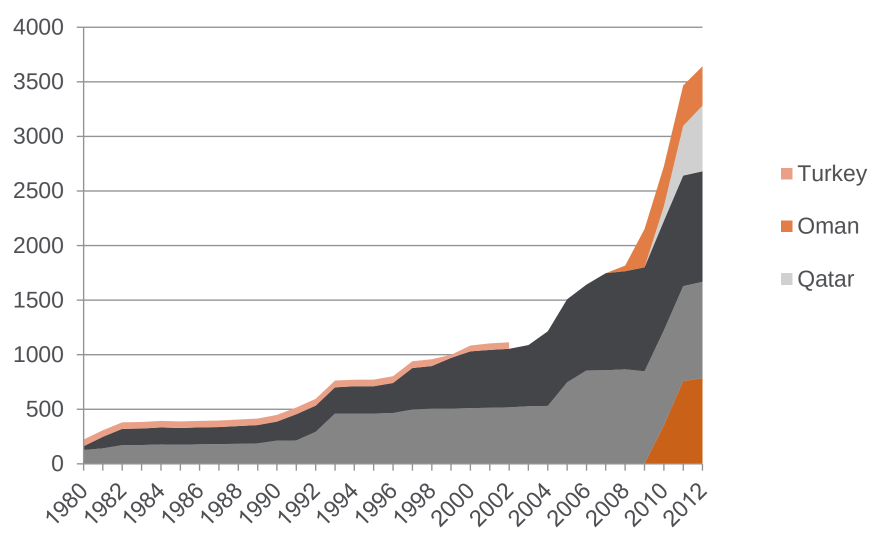


Source: Citi Research

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)

$$\boxed{\text{Capital Costs}} + \boxed{\text{Fuel Costs}} + \boxed{\text{Operational Costs}} = \frac{\boxed{\text{Total Costs}}}{\boxed{\text{Total Life Units}}} = \boxed{\text{LCOE}}$$

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.

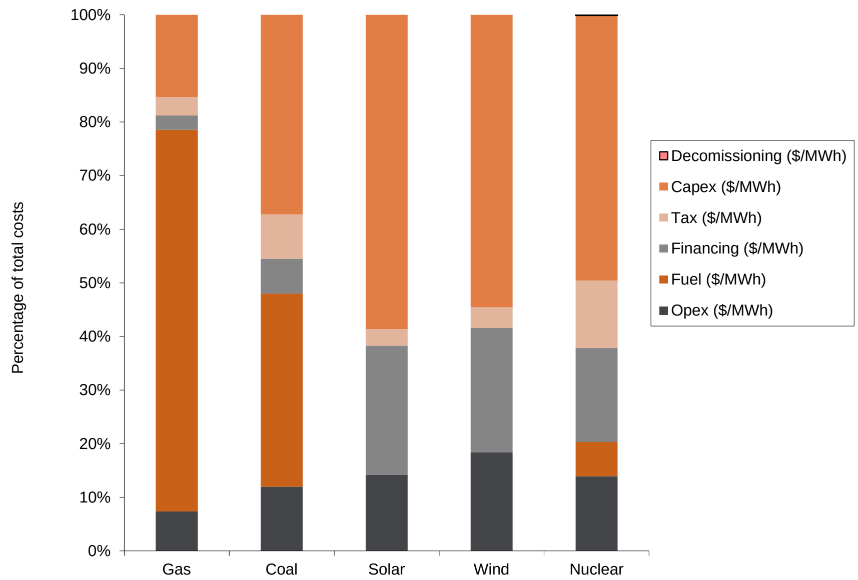
The LCOE considers, on the one hand, the total quantity of electricity produced by the source, and on the other, the costs that went into establishing the source over its lifetime, including the original capital expenditure, ongoing maintenance costs, the cost of fuel, transport and any carbon costs.

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

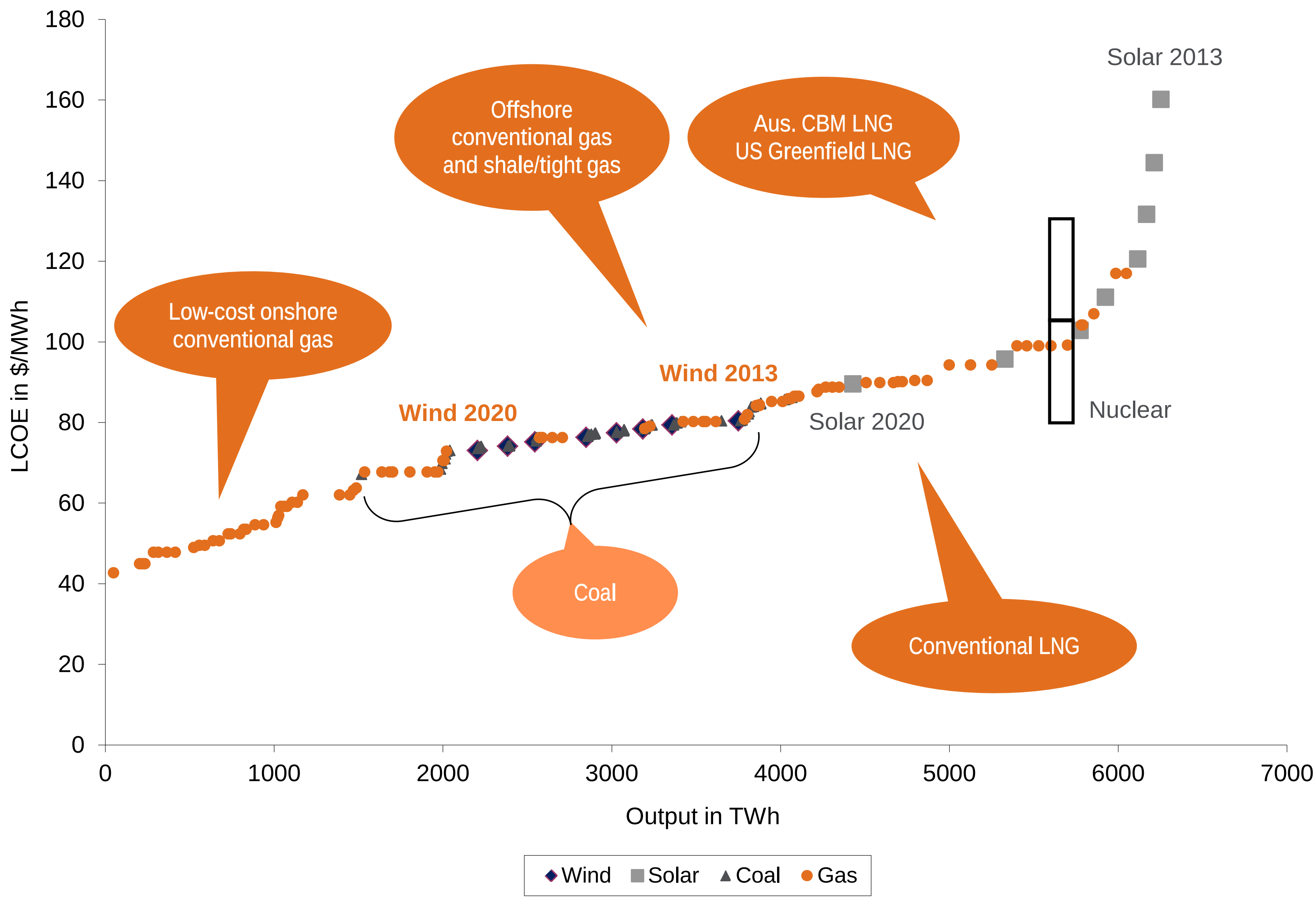
The integrated LCOE cost curve

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



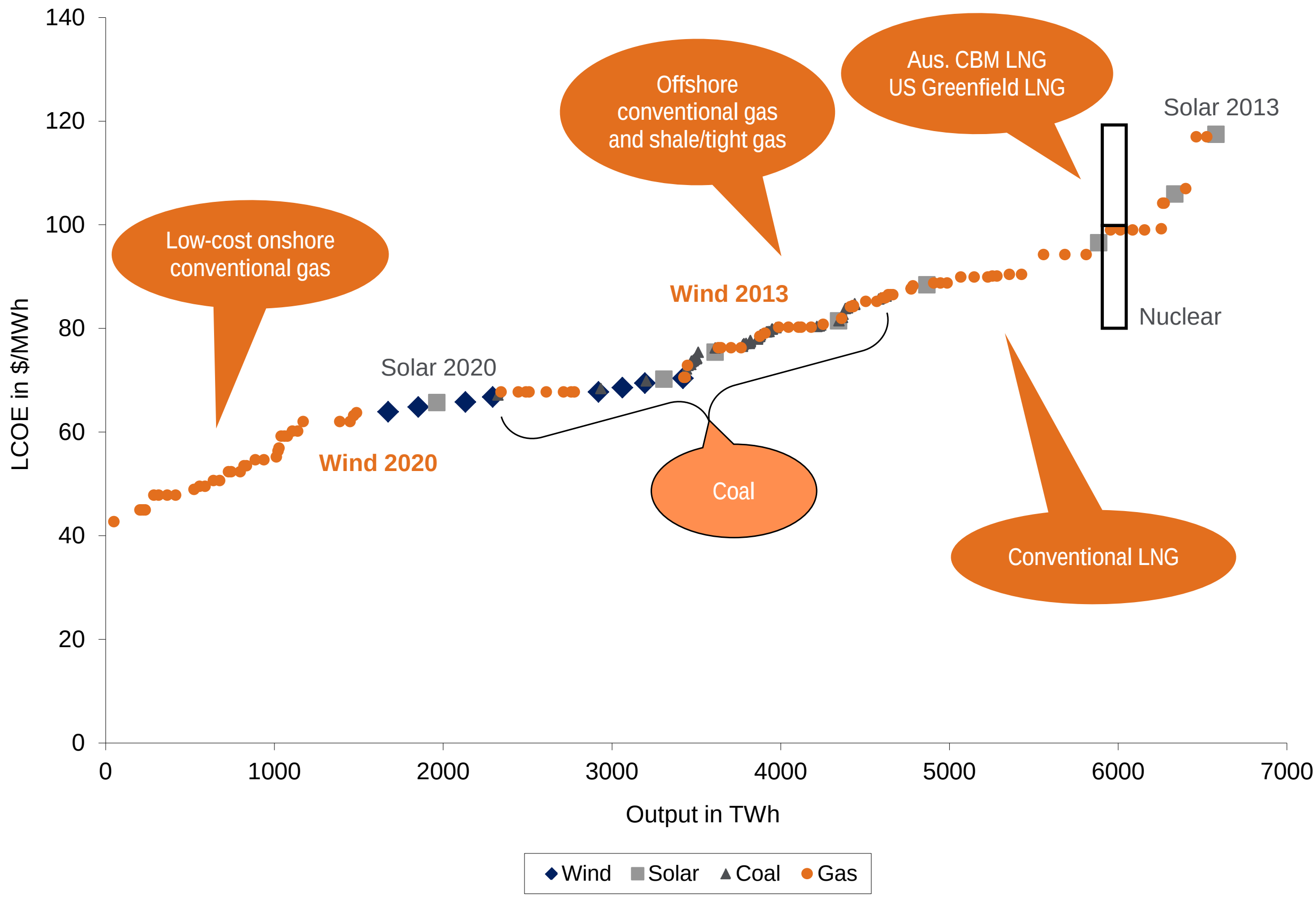
Source: Citi Research

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

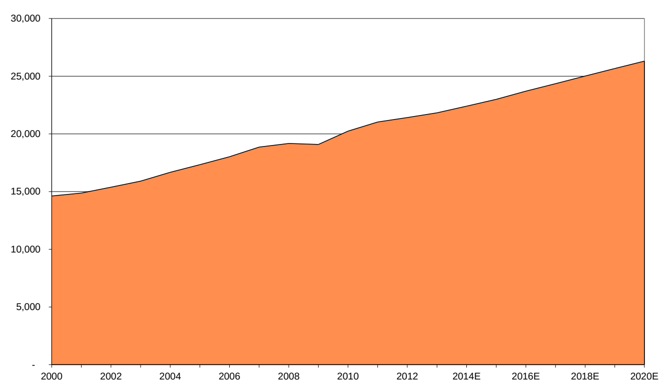
Power generation demand impacts the cost curve at the top of the second quartile

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

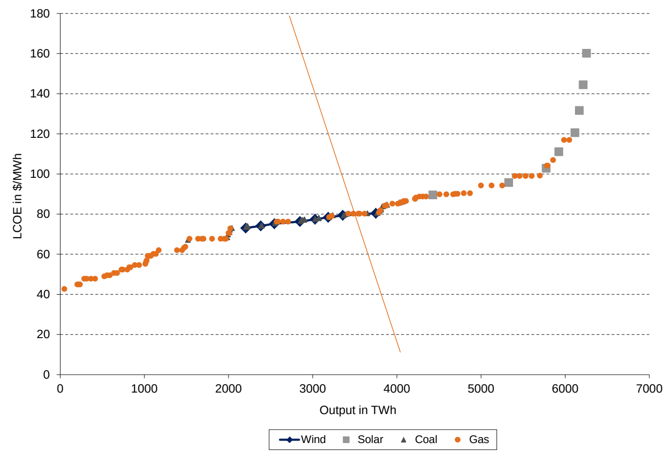
We would also note that in this analysis we have included all gas fields projected to come onstream pre-2020. Currently only about 40% of gas is used for electricity generation, the remainder being used for heat, industry and to a lesser (but increasing) extent transportation. However, this does not 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)



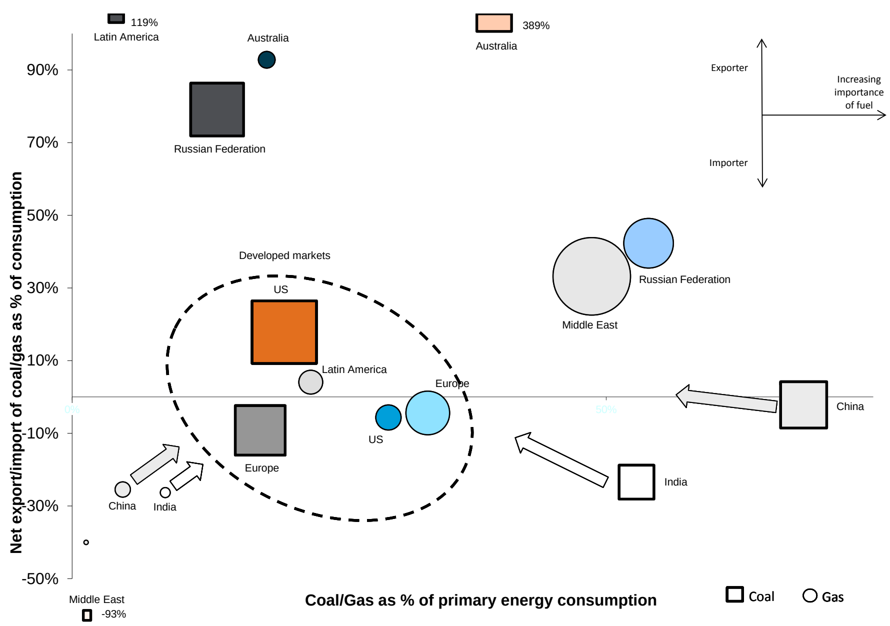
Source: EIA, Citi Research

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.

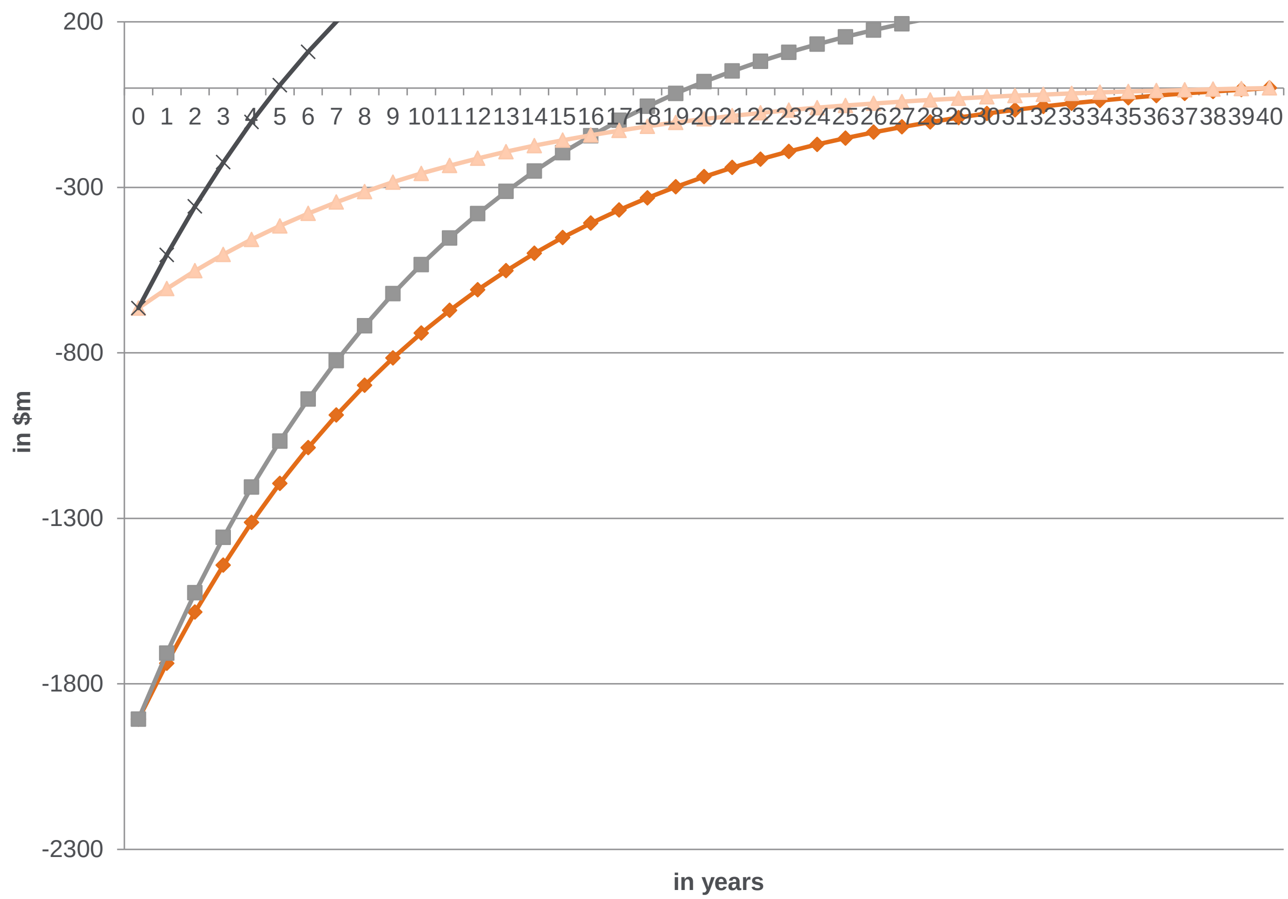
We have taken the upper quartile projected costs for 2020 for gas and coal and then fixed the power price needed to result in a break even after 40 years. We have then dropped the fuel input costs to the lowest quartile for each fuel source by 2020. On a delivered basis for coal the two scenarios are $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

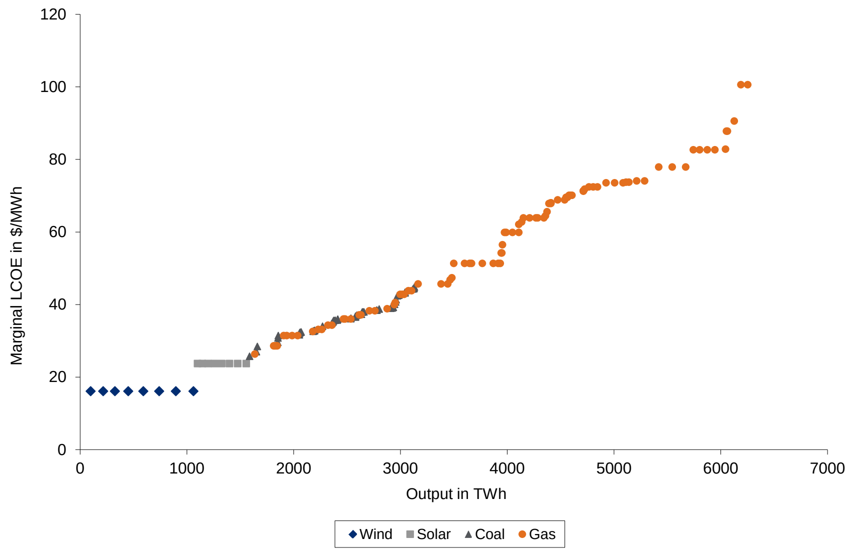


Source: Citi Research

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

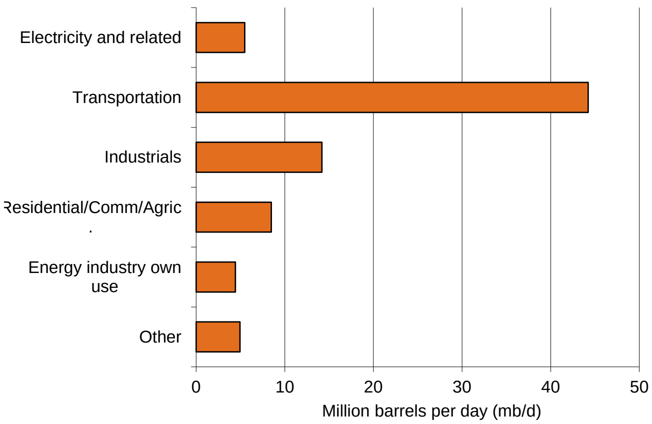
Transport and oil – not immune

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…

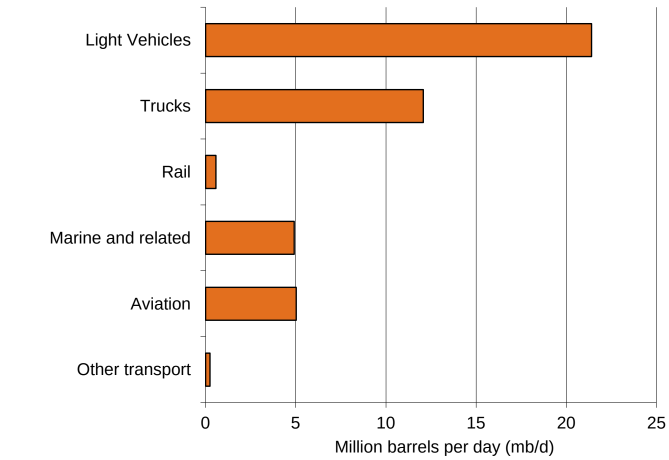
We have not added oil onto our integrated LCOE curve as very little of it is used for power generation, the vast bulk being used for transportation purposes, as shown in Figure 87 and Figure 88.

Figure 87. World oil demand by sector (2010)



Source: IEA, Citi Research

Figure 88. World oil demand for transportation (2010)



Source: IEA, Citi Research

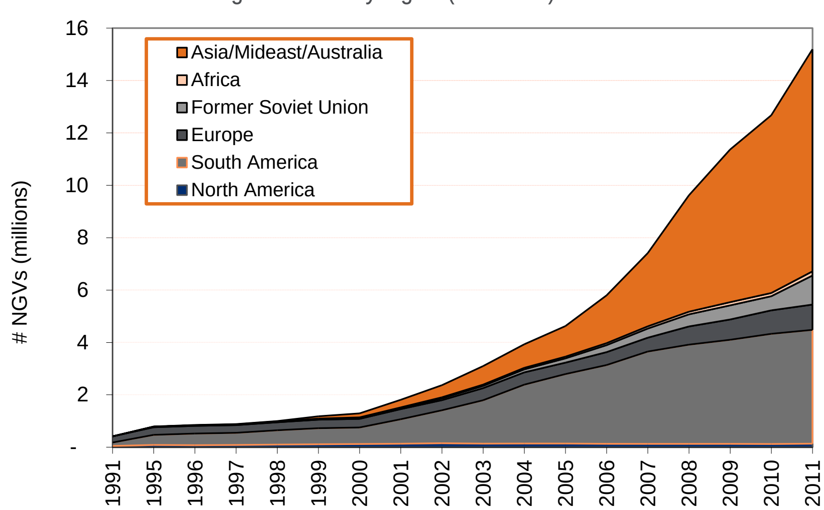
…where it dominates with 95% market share

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!

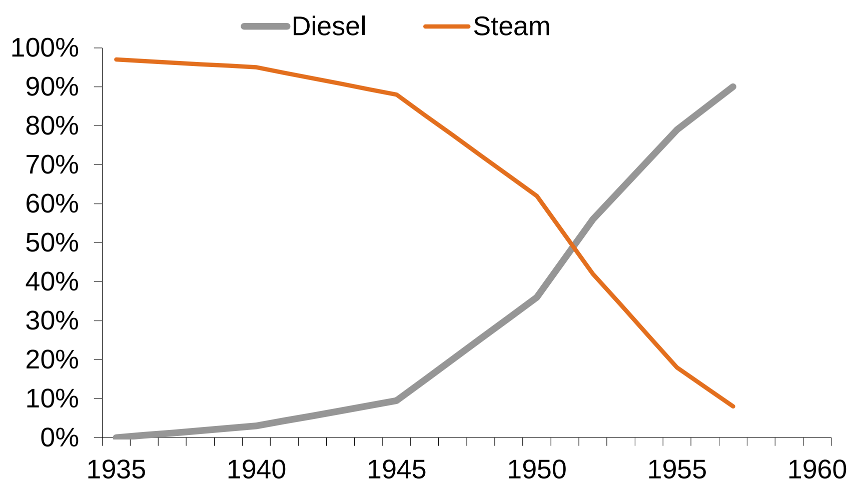
Oil to gas substitution in transportation

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

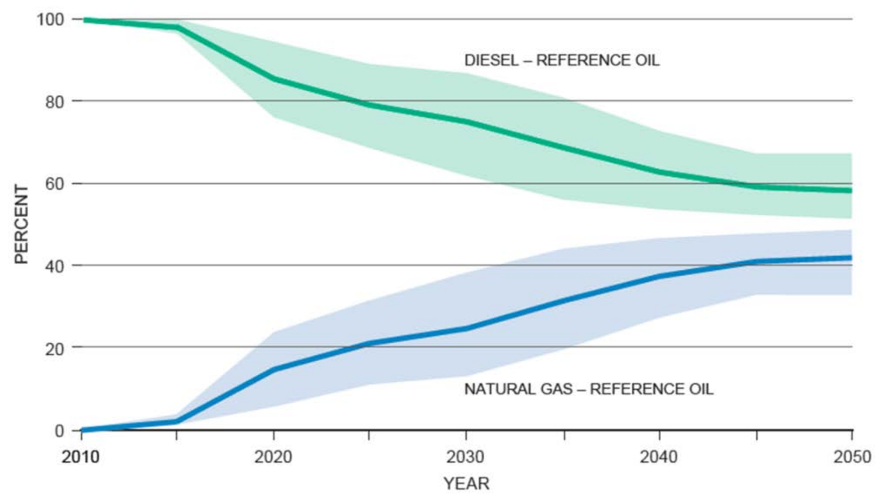
The U.S., Canada, Russia and India are all starting to test liquefied natural gas (LNG) powered locomotives. The costs of modifying a diesel-electric locomotive to running on LNG reportedly run at $600,000 to $1 million, but as one locomotive can burn 400,000 gallons of diesel in a year and on an energy 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

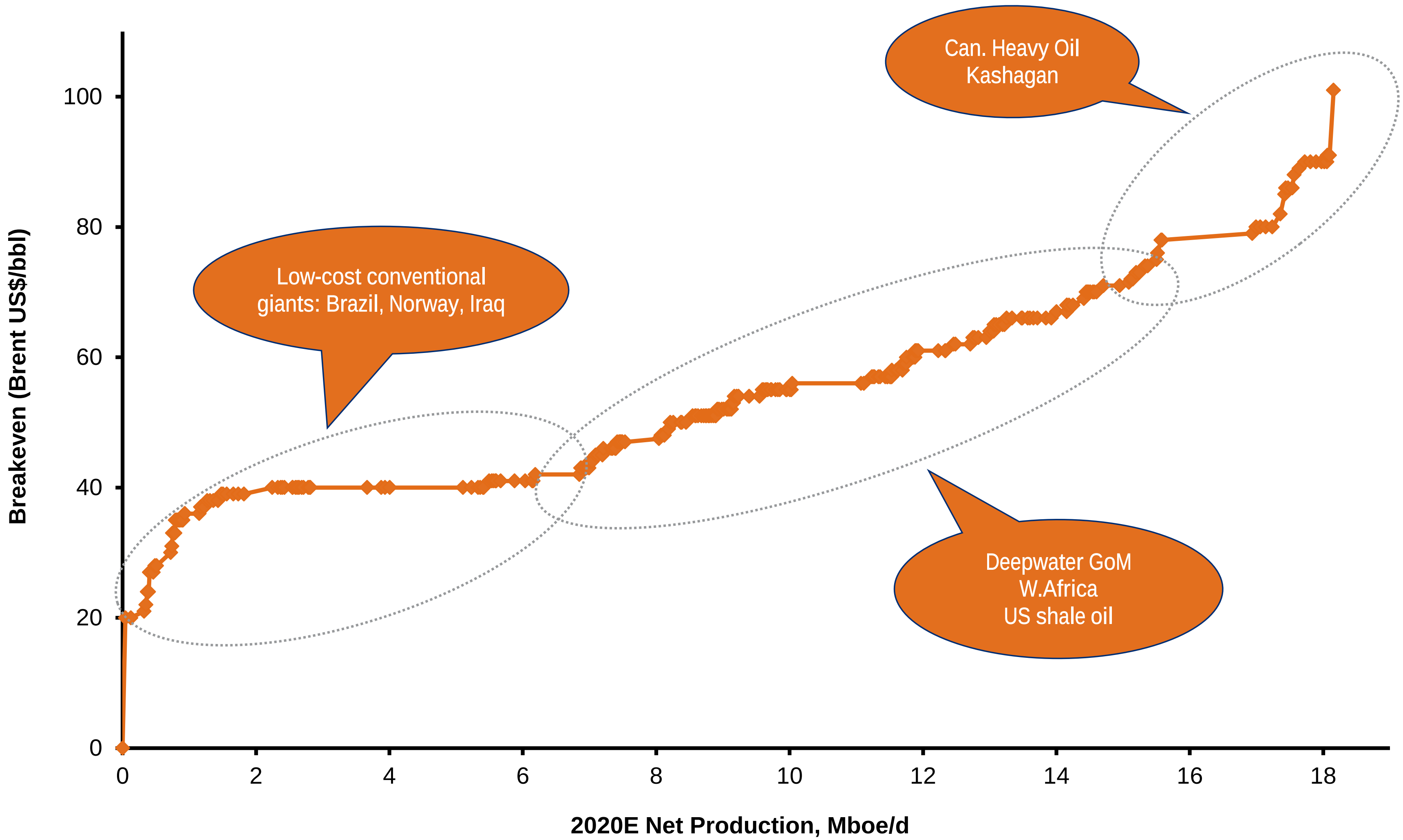
The substitution of gas for oil is a contributing factor to our bearishness on longer-term oil prices. The key drivers of this bearishness are supply side factors - the ramp up in shale/tight oil production in the US and elsewhere by end decade, Iraqi production climbing rapidly over the coming years 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.

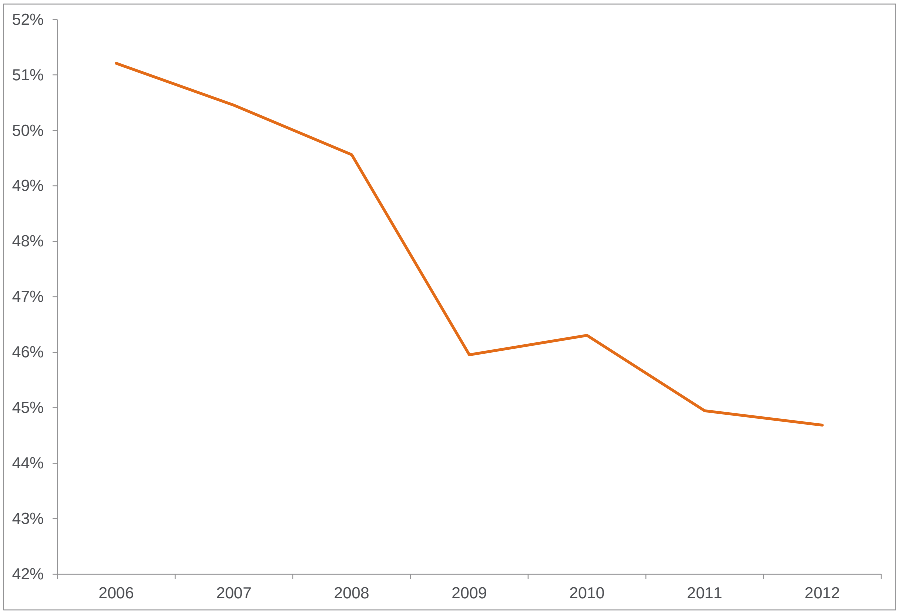
50% reduction potential in volumes sold by traditional utilities through energy efficiency and more distributed energy

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



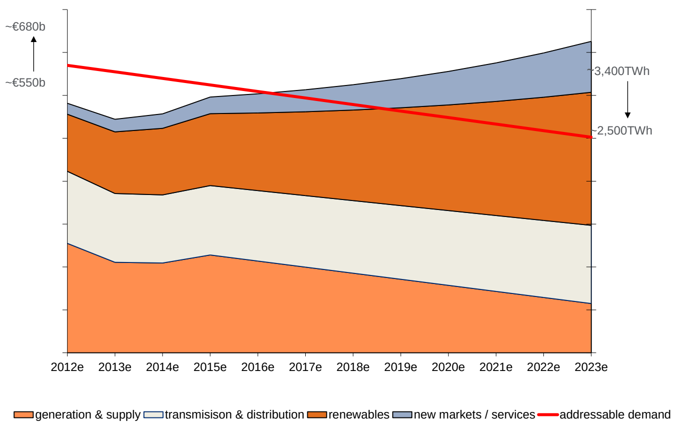
Source: ENTSO-E, NORDEL, Eurostat, NG SYS, Bloomberg, Citi Research

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.

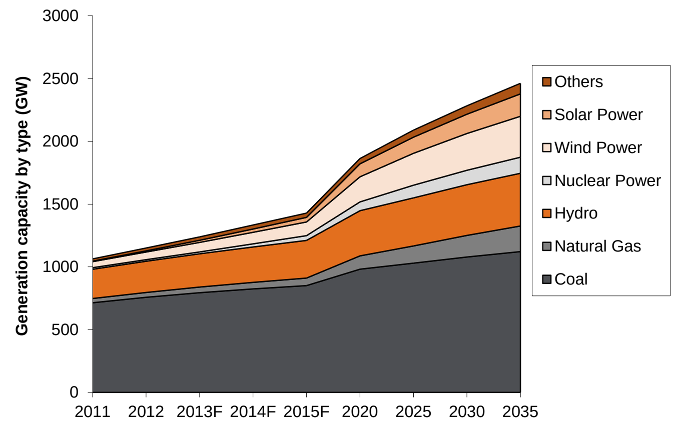
Contrast this declining trend (Figure 94) with the situation in a developing market such as China (Figure 54) where burgeoning demand for both renewable and conventionally-generated power shows the diverse issues facing utilities depending on their location.

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.

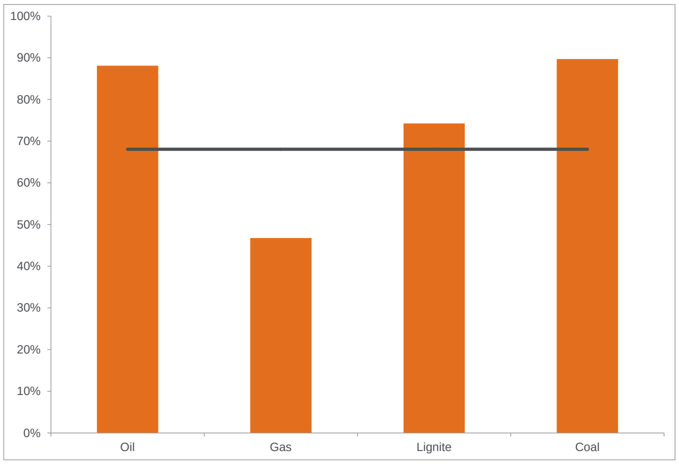
Ageing generation fleets

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.

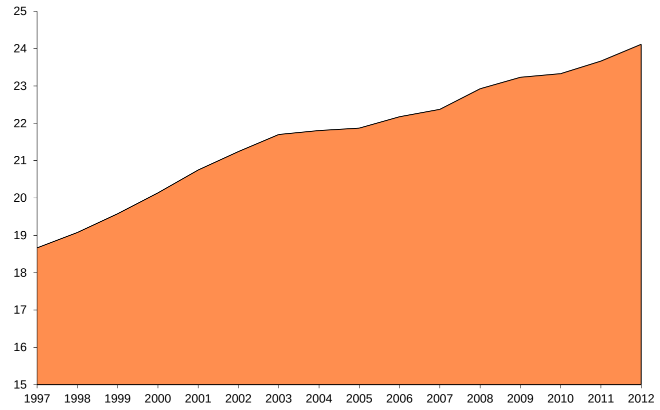
For example, the conventional thermal generational fleet in Europe has gone through more than 2/3rd of its life, as Figure 96 and Figure 97 show. So, although demand is not growing, the maintenance investment on the fleet is rising as the plants are getting older. Citi's European utilities research team 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.

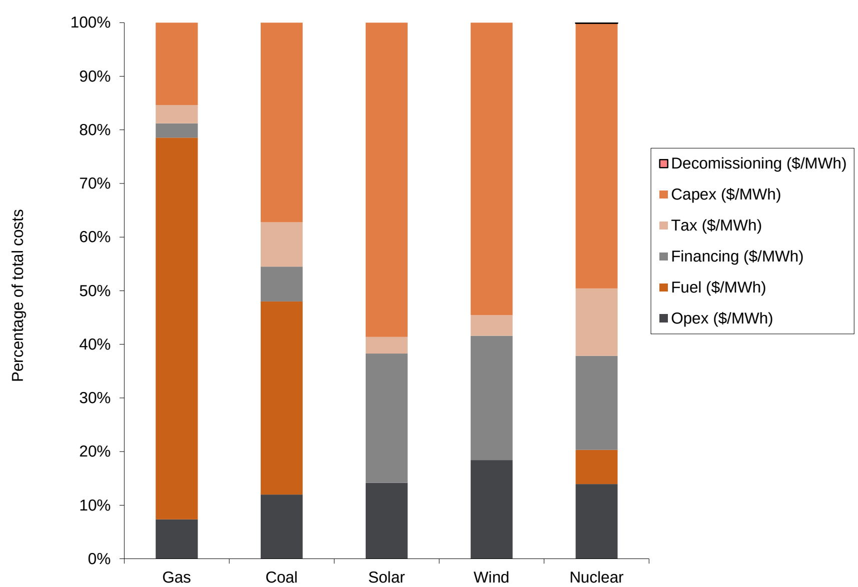
Equipment orders will be affected by changes in the generation mix

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.

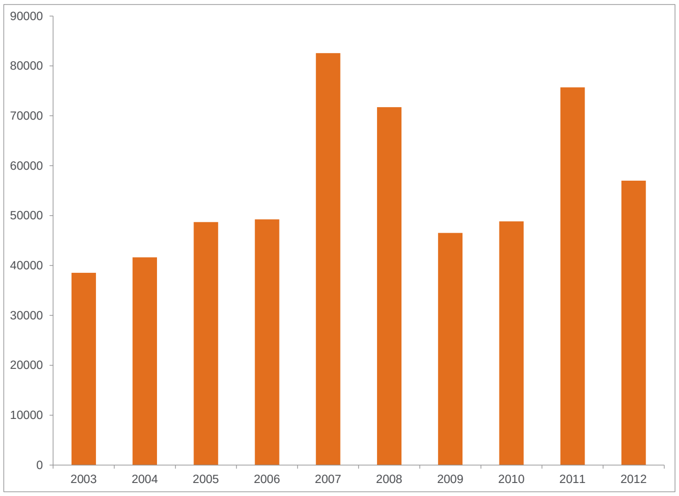
China is the world's largest market…

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

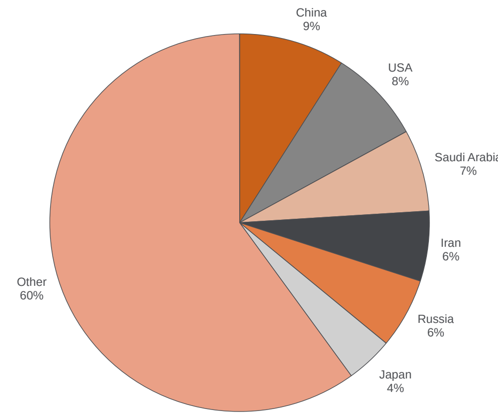
Post the surge in demand in China the US is now second largest market for ordered capacity accounting for 8% of total orders over the past decade. Despite this, ordered capacity in the US still grew 11% year-on-year to 6.2GW in 2012 of which 64% was accounted for by utility providers in the region.

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



Source: McCoy

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

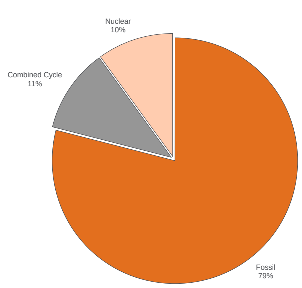


Source: McCoy

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

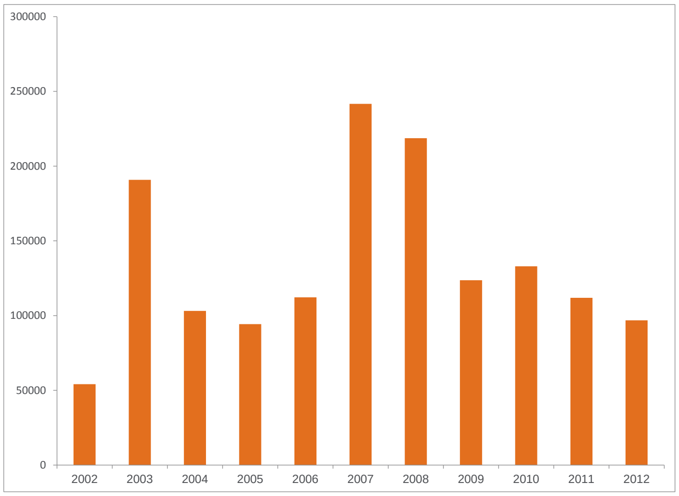


Source: McCoy

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.

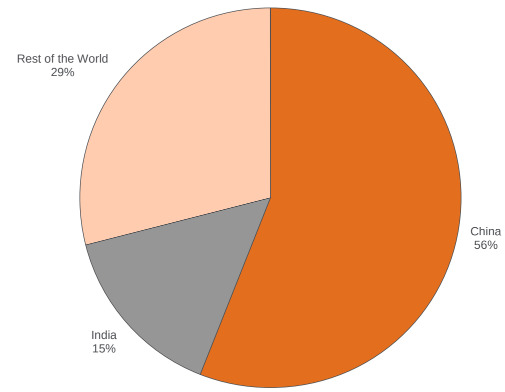
From an application perspective there are three key uses for steam turbines: coal-fired generation (where the steam turbine through steam created as water is heated from the combustion of coal), CCGT generation (where the steam turbine is powered by the hot gases after they have passed through the gas 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

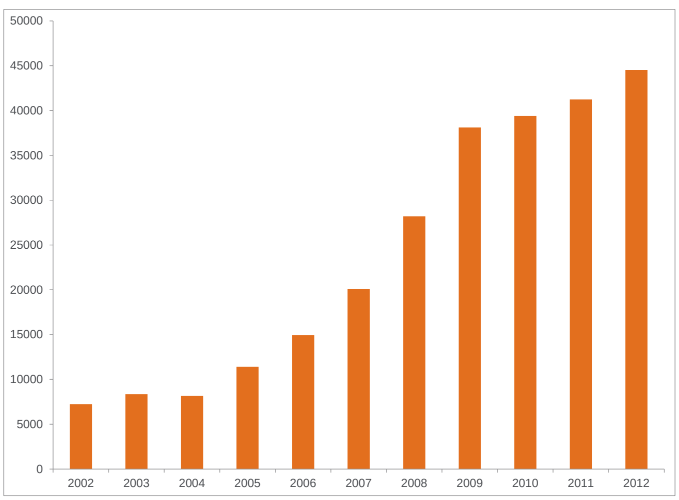
Wind Turbine Technology

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.

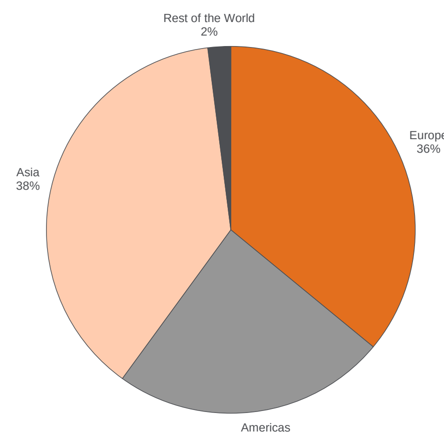
New installations within Europe have grown at just over 6GW per average from 2002-2012 but the growth has mainly been largely skewed to 2002-2008 before both the global financial crisis and the European debt crisis.

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.

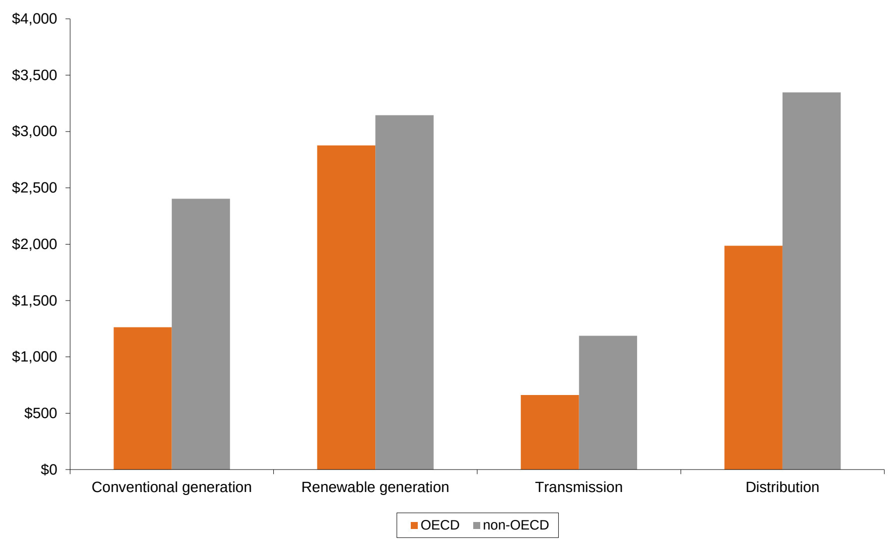
Demand shift has implications for manufacturing location and level of competition

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)

Volume measure with TWh

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.

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)**

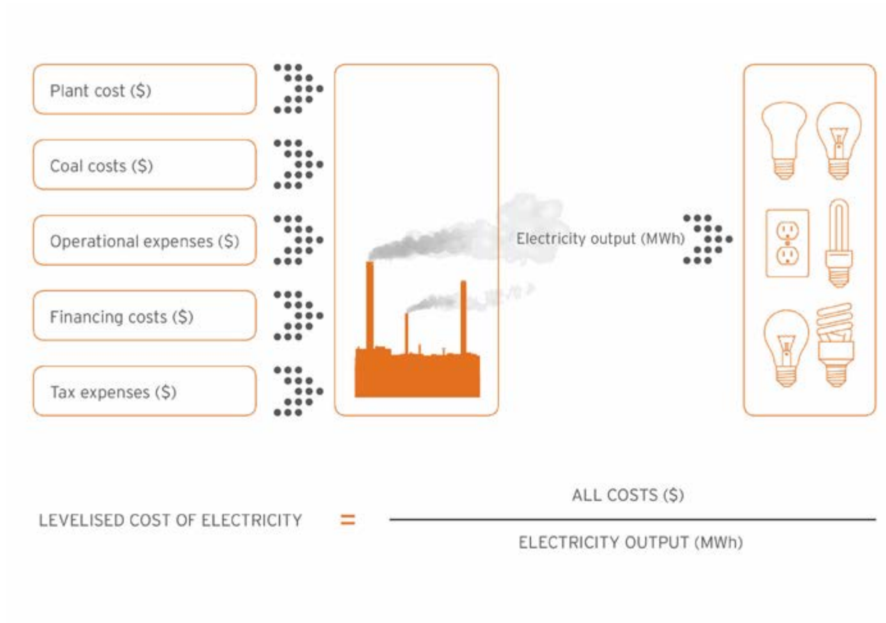
3. **Operational expenses** (these are split into variable and fixed operational expenses; however, these expenses are only incurred when then plant is running. Therefore, they are considered variable costs)

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

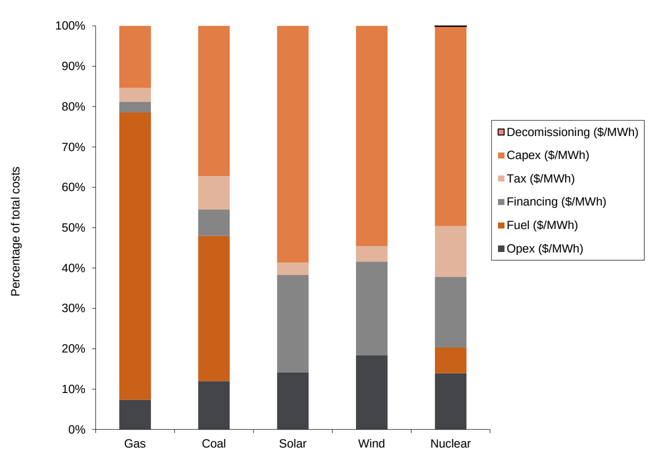


Source: Citi Research
Note: This calculation is conducted over the lifetime of the plant

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

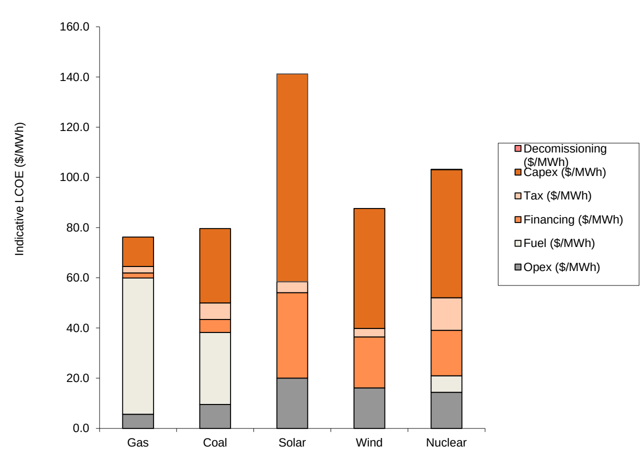
Each of the electricity generating technologies considered are geared differently to the input costs described above and hence carry idiosyncratic risk towards different external factors. Understanding these risks is vital to investing into the energy space. Figure 109 and Figure 110 show the breakdown 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



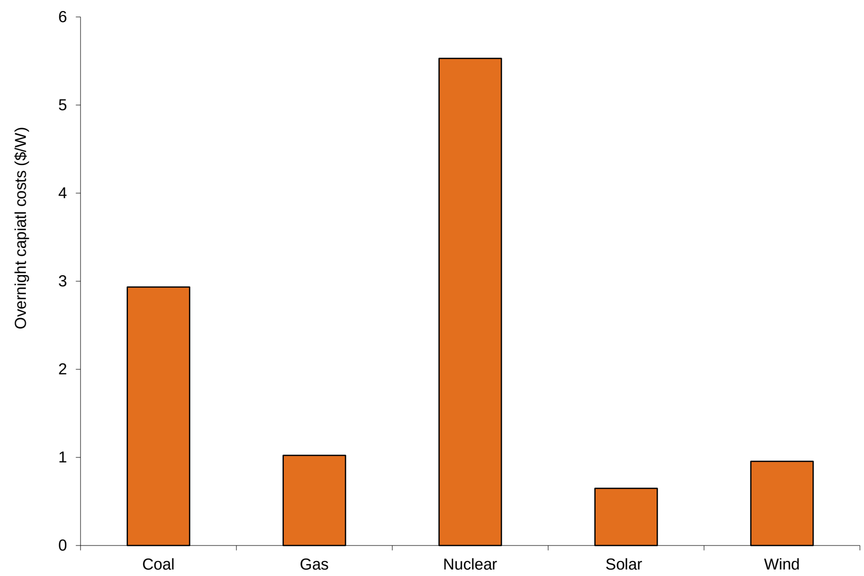
Source: Citi Research

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

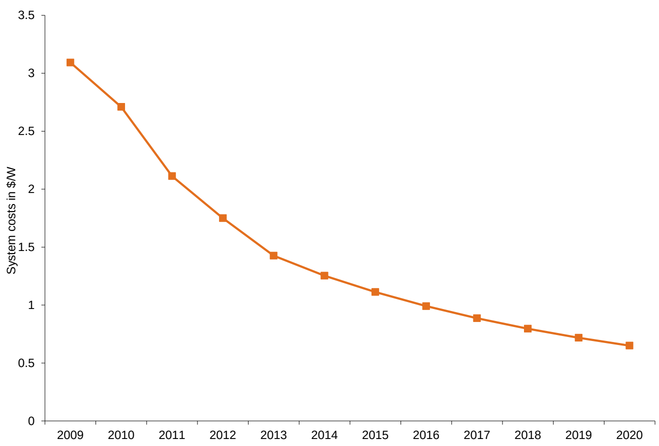
Learning rates of 2% per annum for wind and 9-11% per annum for solar

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

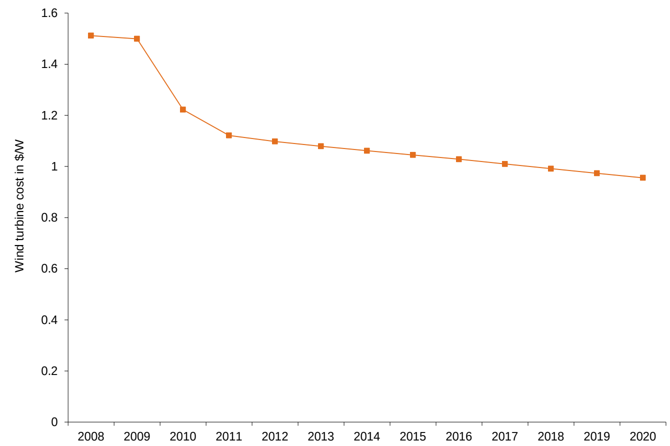
Renewables specialists often plot module and wind turbine learning rates on a log scale vs. the cumulative installation base. In these terms, our forecasts imply a learning rate of 40% for solar and 7% for wind (Figure 114 and Figure 115).

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



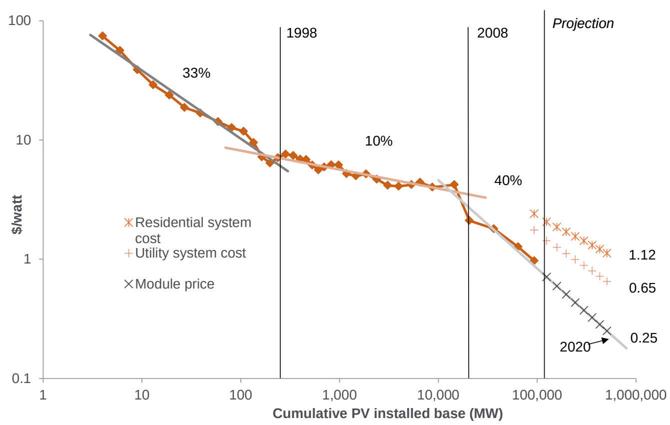
Source: Citi Research

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



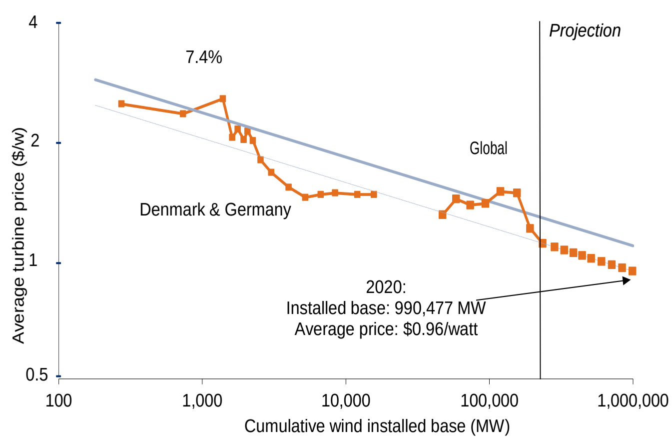
Source: Citi Research

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



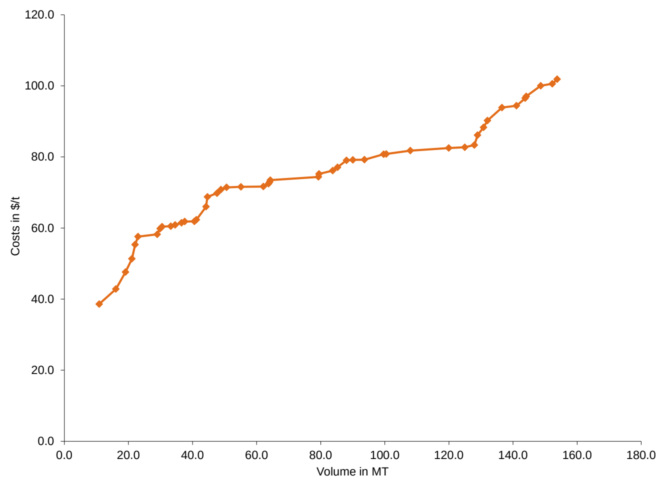
Source: Citi Research, Bloomberg New Energy Finance

Fuel costs

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

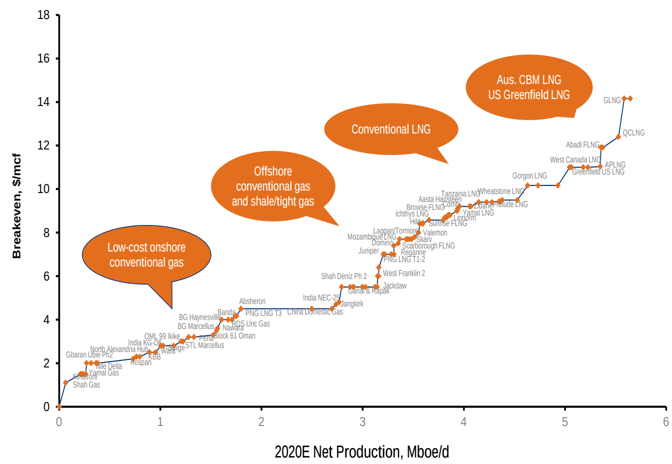
Since solar and wind do not incur fuel costs, we only consider incremental gas and coal projects. Cumulatively, we model about 150 projects that are likely to produce incremental gas and coal by 2020. The following cost curves (Figure 116 and Figure 117) show these coal and gas projects on a cost and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

Figure 116. Incremental coal cost curve - 2020



Source: Citi Research

Figure 117. Incremental gas cost curve – 2020



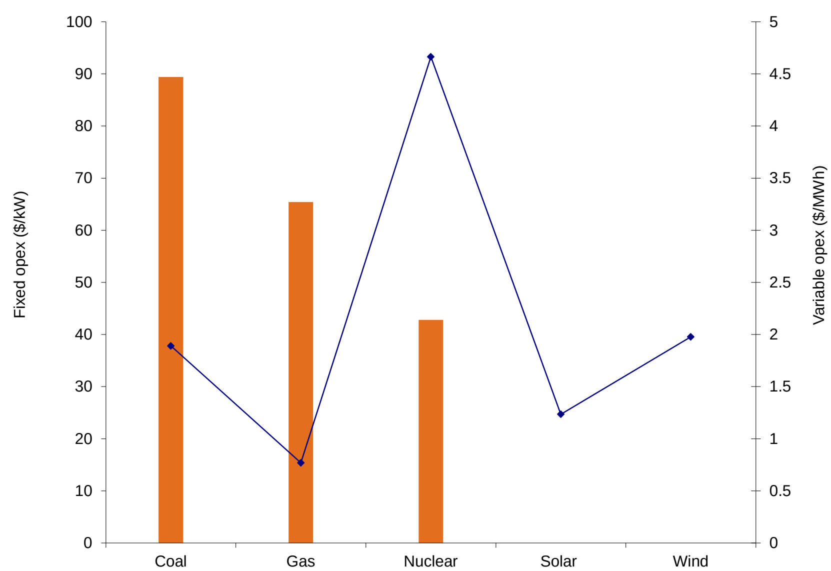
Source: Citi Research

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

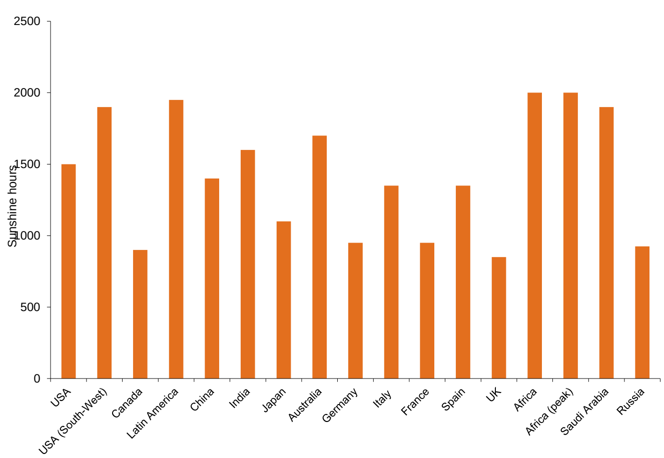
Load factor of 85% for gas, and close to 100% for coal and nuclear assumed

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

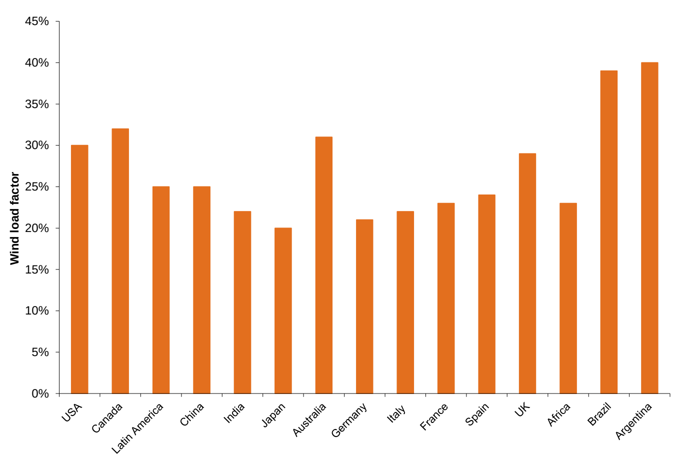
For renewables, the limiting factor is the availability of sunshine and wind resources. These resources vary across different countries. The sunniest regions (Africa and the Middle East) have around 1,800-2,000 equivalent sunshine hours per year (capacity factor: 20-22%) while less sunny regions such 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



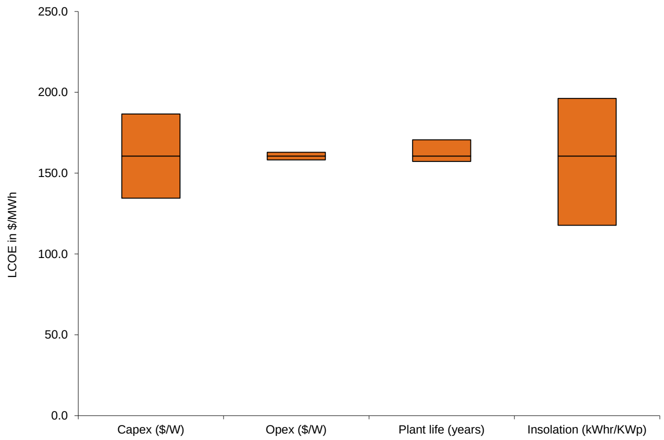
Source: Citi Research

Appendix 2 – Base case and optimistic case

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

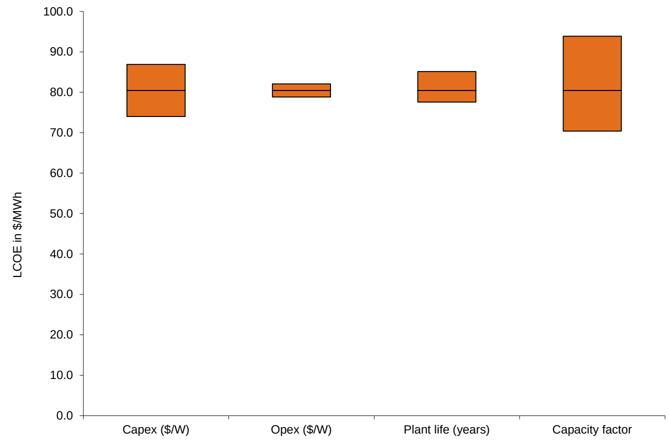
As shown in the sensitivity analysis the load factor on renewables has a very big impact on cost and competitiveness of solar and onshore wind (Figure 121 and Figure 122). For this reason we consider two cases: 1) one where we use standard to pessimistic assumptions about solar/onshore wind load factors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

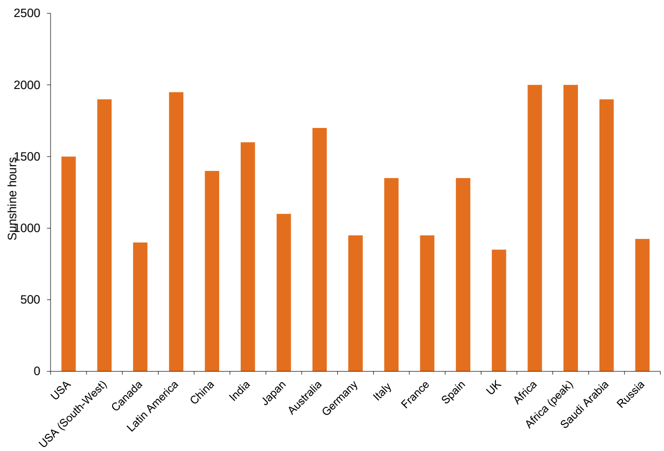
	Solar	Onshore wind
Base case	12.5% (1,100 sunshine hours)	28%
Bull case	17% (1,500 sunshine hours)	32%

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%).

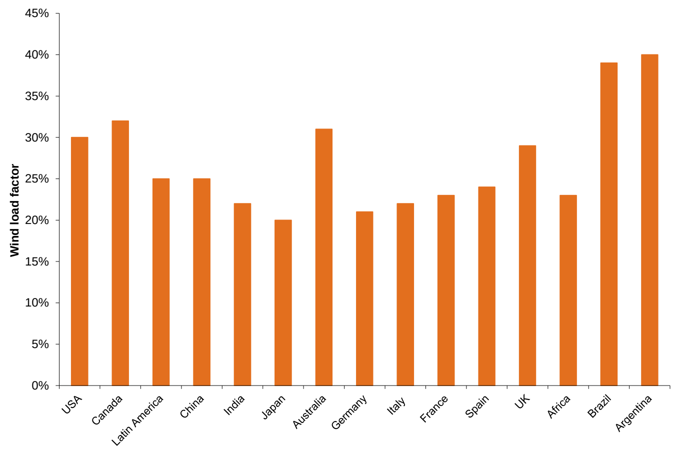
To ensure our assumptions are reasonable we compare them to country specific resource availability in Figure 124 and Figure 125. For solar we see most incremental installations occurring in Japan (1,100 sunshine hours), China (1,400 sunshine hours) and the U.S. (1,500-1,900 sunshine hours) while wind 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

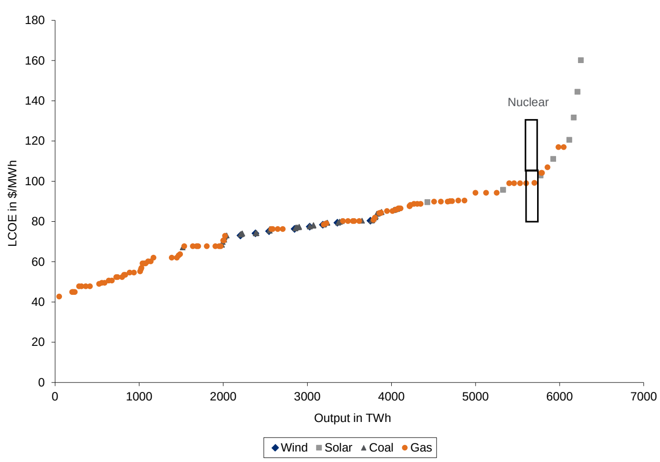
In the base case, solar threatens 3rd quartile gas, in the bull case solar has the potential to threaten 2nd quartile gas by 2020

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

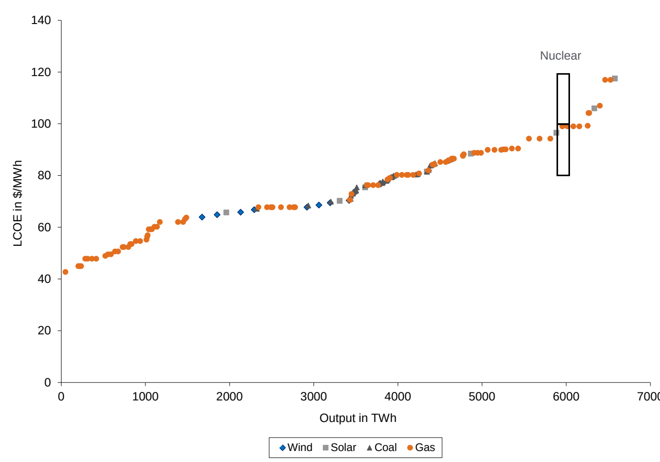
The gains for wind are somewhat less impressive because wind starts off at a better competitive position. In the base case, wind will be able to generate electricity at $75/MWh while the bull case assumes a generation cost of $70/MWh. However we note that wind is already threatening 3rd and 2nd quartile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

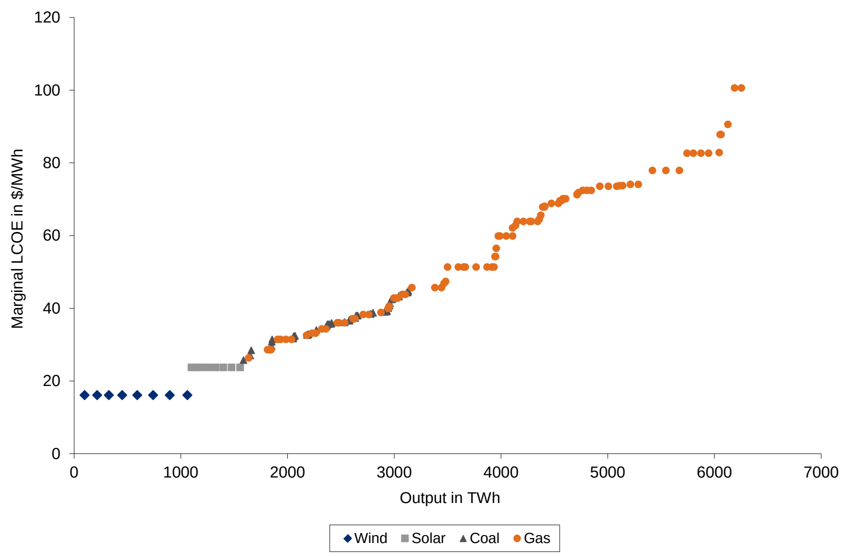
Coal more competitive than gas on a marginal basis, explains preference of coal over gas in Europe

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

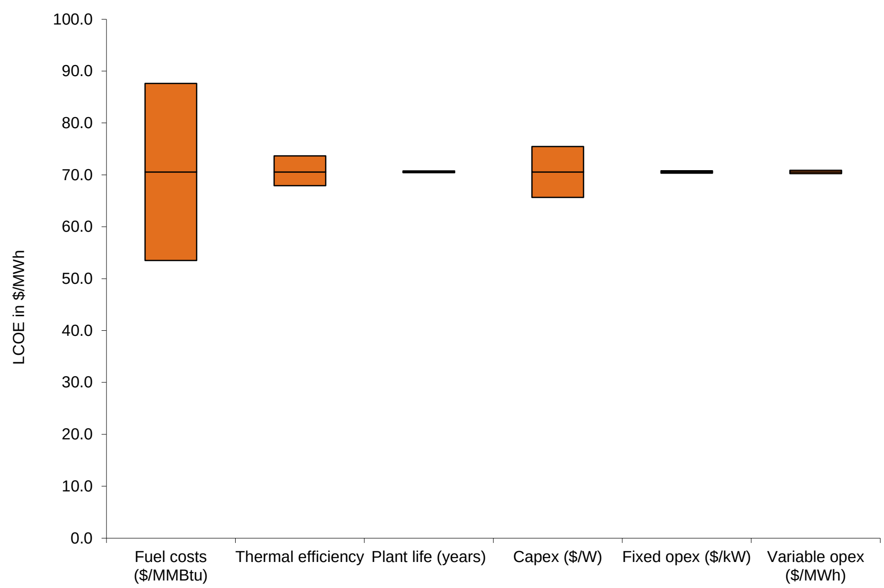
Conversely an investor might have a view on the thermal efficiency of gas plants and assume that we will see significant improvements in the next few years which could bring efficiencies up to 65% (overnight construction with a construction period of 3-4 years). In this case the impact on LCOE and competitiveness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



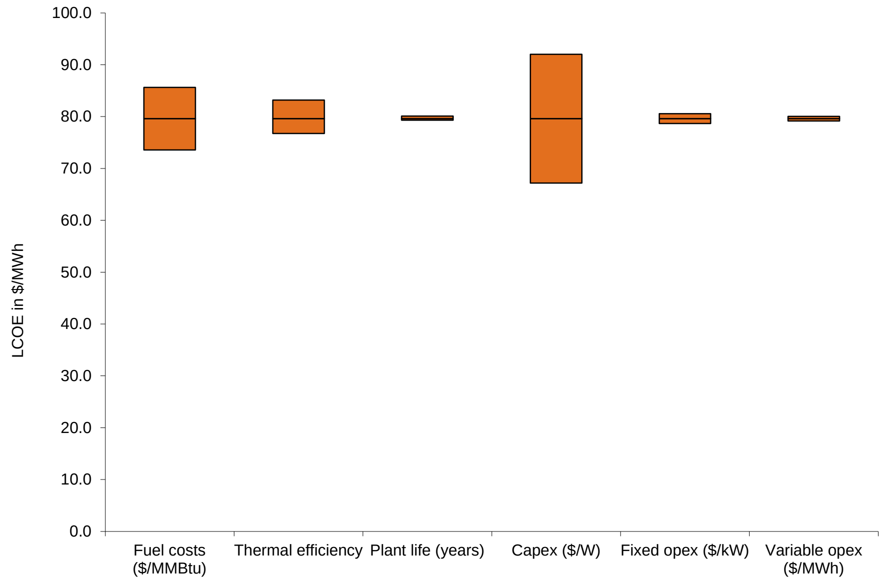
Source: Citi Research

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



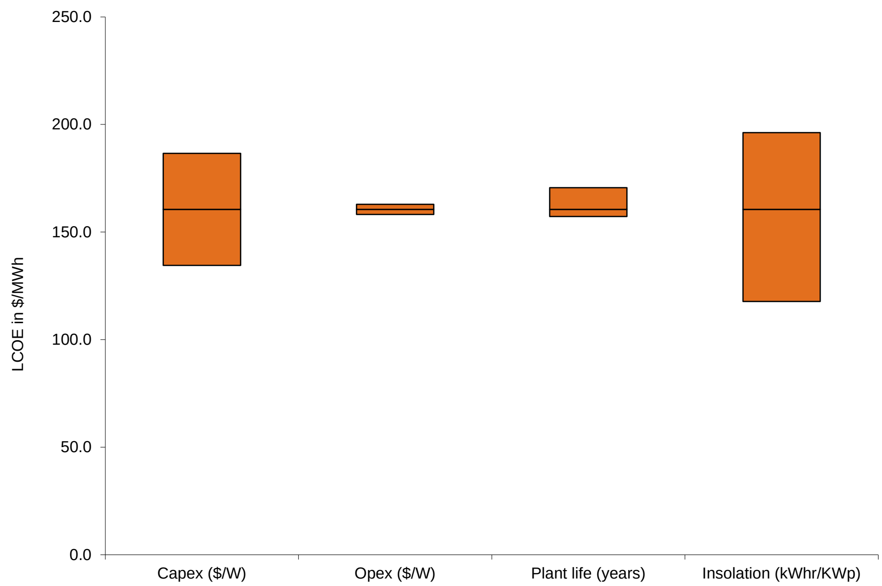
Source: Citi Research

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



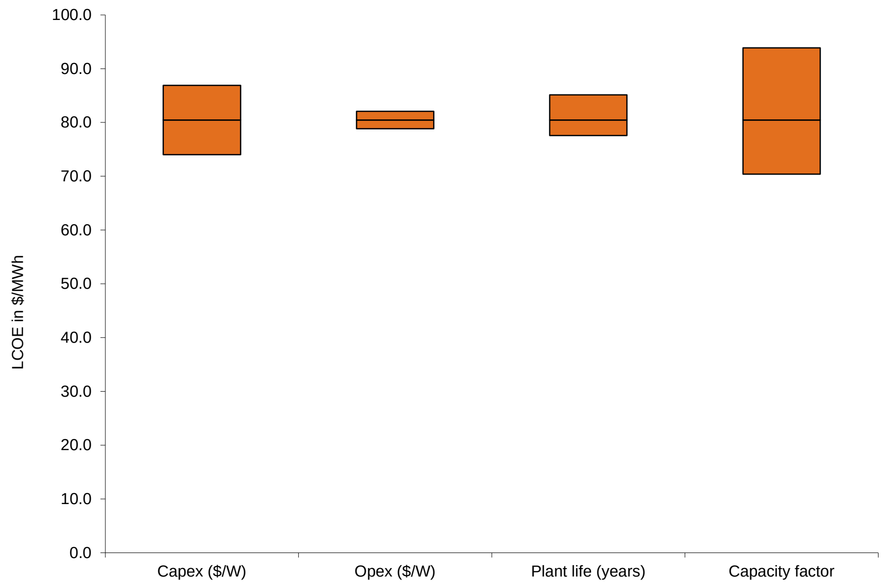
Source: Citi Research

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



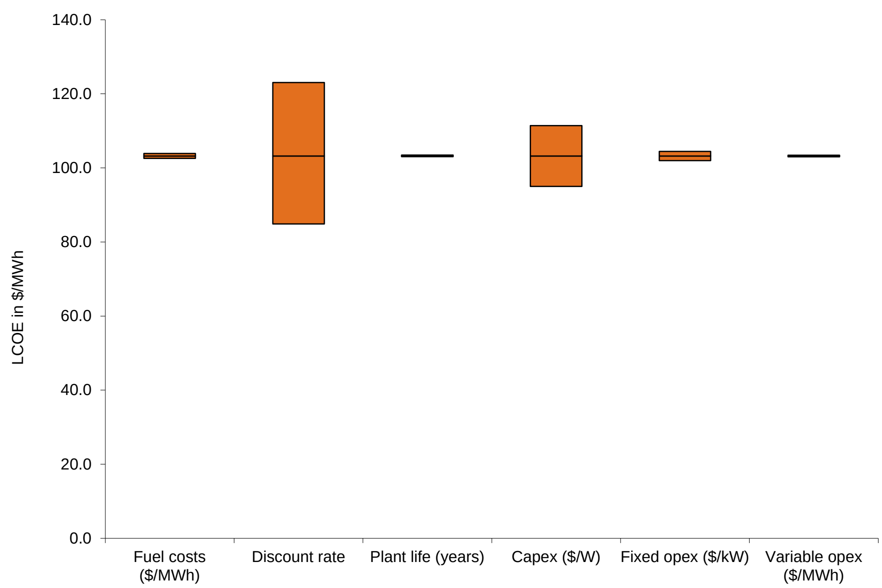
Source: Citi Research

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

IMPORTANT DISCLOSURES

NOW / NEXT

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.

Citi GPS

ENERGY DARWINISM II

Why a Low Carbon Future Doesn't Have to Cost the Earth

Citi GPS: Global Perspectives & Solutions

August 2015

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ENERGY DARWINISM II

Why a Low Carbon Future Doesn't Have to Cost the Earth

As Thomas Edison presciently pointed out to Henry Ford and Harvey Firestone in 1931, *"We are like tenant farmers chopping down the fence around our house for fuel when we should be using nature's inexhaustible sources of energy - sun, wind and tide. I'd put my money on the sun and solar energy. What a source of power! I hope we don't have to wait until oil and coal run out before we tackle that."*

While fossil reserves aren't running out, our ability to burn them without limit may be, due to the fact that atmospheric concentrations of CO_2 and equivalents are rapidly approaching the so-called 'carbon budget' – the level that if we go beyond is likely to lead to global warming in excess of the important 2^oC level.

It is this that makes the United Nations COP21 meeting in Paris in December 2015 so important; it represents the first real opportunity to reach a legally binding agreement to tackle emissions, given that all parties, including the big emitters, are coming to the table with positive intentions, against a backdrop of an improving global economy.

We live though in an energy hungry world. Global GDP is set to treble by 2060, with two thirds of that growth coming from emerging markets which display significantly greater energy and carbon intensity per unit of GDP than developed markets. Feeding that energy demand and facilitating growth while minimizing emissions will take brave and coordinated decisions on the part of policymakers.

In this report, we examine the likely costs of inaction in terms of the potential liabilities from climate change to see whether we can afford not to act. We also examine whether the world *can* afford to act, by comparing the incremental costs of following a low carbon path to global GDP. Overall, we find that the incremental costs of action are limited (and indeed ultimately lead to savings), offer reasonable returns on investment, and should not have too detrimental an effect on global growth. Nevertheless, our energy choices will have a profound impact on countries, industries and companies, and we examine the implications of a low carbon future in terms of the stranded assets that are likely to result. Finally, we examine the solutions that financial markets and institutions can offer to facilitate this transition to a lower carbon world.

We are not climate scientists, nor are we trying to take sides in the global warming debate, rather we are trying to take an objective look at the economics of the discussion, to assess the incremental costs and impacts of mitigating the effects of emissions, to see if there is a 'solution' which offers global opportunities without penalizing global growth, whether we can afford it (or indeed we can afford not to), and how we could make it happen.

We believe that that solution does exist. The incremental costs of following a low carbon path are in context limited and seem affordable, the 'return' on that investment is acceptable and moreover the likely avoided liabilities are enormous. Given that all things being equal cleaner air has to be preferable to pollution, a very strong "Why would you not?" argument begins to develop.

With the global economy improving post-crisis, interest rates low, the large emitters coming to the table, investment capital keen, and public opinion broadly supportive, Paris offers a generational opportunity; one that we believe should be firmly grasped with both hands.

Action versus Inaction

Limited differential in total bill but potentially enormous liabilities avoided

CUMULATIVE CO_2 EMISSIONS ARE GETTING CLOSE TO THE 3,010 GT 'CARBON BUDGET'

1870	2.4
1910	159.5
1950	434.7
1970	740.0
2010	1844.5
2013	1960

1,050 $GTCO^2$ left to burn to have a 50% chance to reach 2°C

Source: Citi Research, Boden et al. (2013), Houghton et al. (2012)

GLOBAL GDP IS EXPECTED TO TREBLE WITH STRONG GROWTH FROM EMERGING MARKETS

2015
$80 trillion

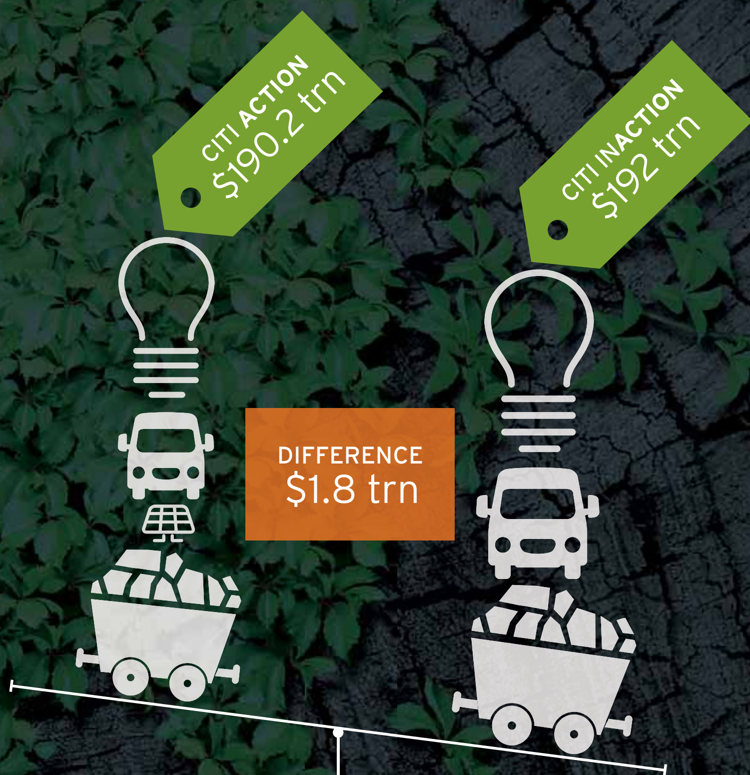
2060
$260 trillion

2/3rds of global GDP growth is expected from non-OECD countries who tend to be more energy intensive

Source: OECD

THE ESTIMATED SPEND ON FUEL COSTS AND CAPITAL EXPENDITURES GLOBALLY IS $1.8 TRILLION LESS IN CITI'S ACTION SCENARIO

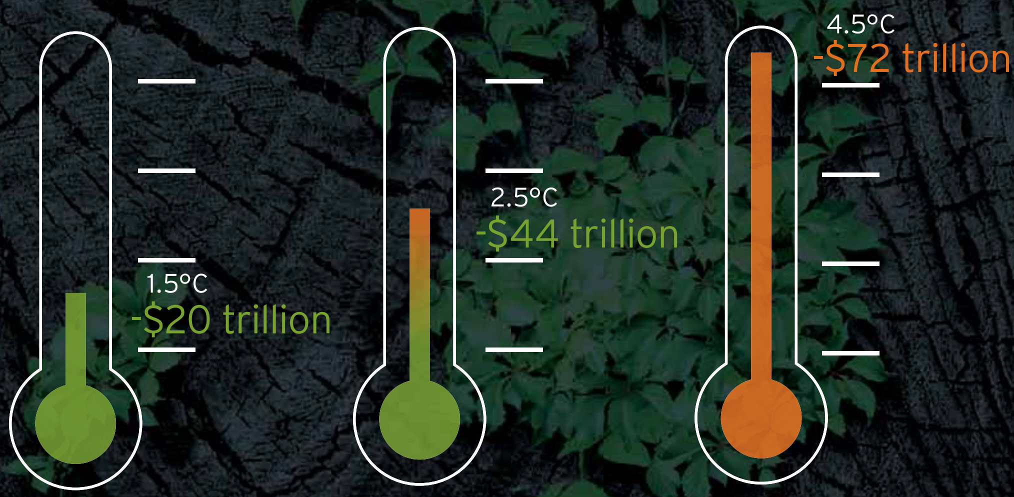
- Power
- Transport
- Energy efficiency
- Other



Source: Citi Research

BUT THE DAMAGE TO GDP FROM THE NEGATIVE EFFECTS OF CLIMATE CHANGE IS SUBSTANTIAL

0% discount rate



Change in global GDP	-0.7%	-1.1%	-2.5%

Source: OECD

Contents

Introduction

Citi forecasts that the sums of money to be spent on energy (both capital expenditure and fuel) over the next quarter century will be unimaginably large, at around $200 trillion. The energy industry is faced with choices, and in this report, we outline two scenarios: 1) a business as usual or 'Inaction' on climate change scenario, and 2) a different energy mix that offers a lower carbon alternative. We find that out to 2040 the levels of spend are remarkably similar; indeed the 'Action' scenario actually results in an undiscounted saving of $1.8 trillion over the period, as while we spend more on renewables and energy efficiency in the early years, the savings in fuel costs in later years offset earlier investment.

If the scientists are correct, the potential liabilities of not acting are equally vast. The cumulative 'lost' GDP from the impacts of climate change could be significant, with a central case of 0.7%-2.5% of GDP to 2060, equating to $44 trillion on an undiscounted basis. If we derive a risk-adjusted return on the extra capital investment in following a low carbon path, and compare it to the avoided costs of climate change, we see returns at the low point of between 1% and 4%, rising to between 3% and 10% in later years.

So can we afford to act? Examining the extra spend required in our 'Action' scenario in the context of global GDP, we find that on an annual basis we only have to spend around 0.1% of GDP more on energy, and that on a cumulative basis at its worst point, the extra investment only amounts to around 1% of global GDP. Moreover, against a backdrop of secular stagnation, that extra investment may actually help to boost growth.

These changes in energy mix inevitably have significant implications in terms of which fossil fuel assets will be burnt, and which not. Some studies suggest that globally a third of oil reserves, half of gas reserves and >80% of coal reserves would have to remain unused before 2050 for us to have a chance of staying below the 2^{o}C limit. We examine the issue of unburnable carbon and stranded assets, in particular in which countries, industries and companies they are located, and find that at current prices, around $100 trillion of assets could be 'carbon stranded', if not already economically so. The clear loser stands to be the coal industry, though we examine the economics and potential offered by carbon capture and storage.

So how do we make this investment happen? Almost all of the growth in energy demand is forecast to come from emerging markets, while most of the new investment in developed markets will be into energy efficiency, both of which represent challenges to investment. While Development Finance Institutions have to date provided much of the investment in emerging markets, these now find themselves effectively 'maxed out'.

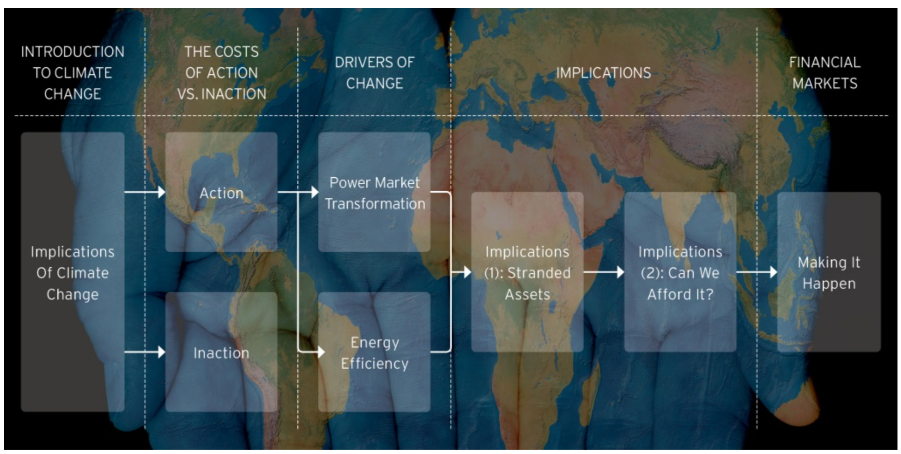
There is a clear need for the investment, balanced by enormous investor appetite for these types of investments; the missing link has been the lack of, and quality of the investment vehicles available. Hence financial markets must innovate to facilitate investment via the creation of new instruments, vehicles and markets. We see the greatest opportunity in the credit markets, yet the challenge will be to raise the quality of the instruments available to investment grade via credit quality enhancement, securitization and other methods. We examine the potential solutions that financial markets can offer, and highlight the enormous opportunity that this presents.

Overview

This report examines the threats and opportunities presented by climate change, looks at its implications and how to mobilize the finance to tackle it.

- **Introduction to Climate Change**: The report begins with an overview of climate change, emissions levels and what the forthcoming United Nations meeting in Paris in December 2015 is attempting to achieve (and why).
- **The costs of inaction and action:** We examine the costs of inaction in terms of GDP potentially lost due to climate change, and compare this with the potential costs of action in terms of mitigating climate change.
- **Drivers of change**: The next chapters examine the drivers of this mitigation strategy, namely the transformation of the power market, and lower energy use via increased investment in energy efficiency.
- **Implications of change:** We then examine the implications of that investment to help prevent climate change, in terms of its effect on global GDP, but also the effect of the energy mix shift in creating stranded assets in certain industries.
- **Making it happen:** Finally, we examine the methods and instruments through which financial markets, financial institutions, regulators and policy makers can enable the capital to flow to address this important issue.

Figure 1. Structure of the Report



Source: Citi Research

An Introduction to Climate Change

Highlights

- The UN COP21 meeting will be held in Paris in December 2015 with the aim of reaching a global legally binding agreement designed to keep global temperature increases to below 2°C, a level designed to avoid the worst effects of climate change

- Prior to the meeting, countries must submit their pledges and plans to reduce emissions which can then be aggregated and compared to the so-called 'carbon budget' – the amount of greenhouse gases (GHG) we can still emit before temperatures are committed to rising above 2°C. This then forms a starting point for negotiations in how the world can go further, given that these aggregated pledges are likely to be above the 'carbon budget'.

- So far a total of 21 countries and the EU have submitted their pledges to reduce GHG emissions. These countries represent over 56% of total GHG emissions that are currently emitted.

- Another objective of the COP21 meeting is the mobilization of $100 billion per year from developed countries to developing countries. It is not yet quite clear how such funds will be mobilized, however an initial capital of $10.2 billion has been pledged by 33 countries through the Green Climate Fund.

- There are three key ways to tackle climate change, namely adaptation, mitigation and geoengineering. We focus mainly on mitigation in this report as it represents shorter term action and is more easily quantifiable.

- The energy sector contributes two thirds of greenhouse gas emissions with CO_2 emissions representing 90% of the total energy-related emissions. The rest of the greenhouse gas emissions are attributed to agriculture, land use and forestry sector and other industrial processes.

- Coal represented 43% of annual CO_2 emissions in 2013, followed by oil (38%) and gas (18%). The electricity sector was responsible for emitting 42% of energy-related CO_2 emissions.

- In 2013, China was responsible for emitting over 27% of total energy-related CO_2 emissions, followed by the US (14%) and the EU (9%). Cumulative CO_2 emissions show a different picture with the US being the largest emitter followed closely by the EU.

- To limit temperature increase to 2°C would require CO_2 emissions (not including CH_4 and N_2O) to be limited to approximately 3,010GT CO_2. We have already emitted more than 60% of this total 'carbon budget', leaving little room to expand CO_2 emissions if we are serious about limiting the temperature increase to 2°C.

- If it wasn't for land and ocean 'carbon sinks', annual carbon dioxide concentrations would be accumulating in the atmosphere at a much higher rate.

Introduction

Over the years, scientists have become increasingly confident that humans are re-shaping the Earth's climate. Scientifically, much of what was needed to start worrying about global warming or climate change was known in the late 1950's, although society generally didn't become concerned about the topic until the 1980's. From the late 1980's, the regulation of climate change started gathering steam and scientists through the use of super computer models were able to start studying the climate in more detail. In 1988, the Intergovernmental Panel on Climate Change (IPCC) was created and charged with assessing the science of climate change, bringing together climate change scientists, social scientists, engineers and other experts to discuss the new science on this critical topic.

One purpose of the IPCC was to determine whether formal diplomatic talks would need to be undertaken to discuss the issue of greenhouse gas emissions. The conclusion was obviously a 'yes' and a new treaty called the United Nations Framework Convention on Climate Change (UNFCCC) was signed in Rio in 1992, by 108 heads of state (Victor D.G., 2011)[1]. The objective of the treaty was to 'stabilize greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system' (UNFCCC). Since then, the parties of the convention have met annually from 1995 in the Conferences of the Parties (COP) to assess the progress in dealing with climate change. The Kyoto Protocol was signed in 1997 at one such meeting, which after ironing out all the details finally came in force in 2005.

Parties in Cancun agreed to limit temperature increase to 2°C

The Cancun agreement in 2010 stemmed from another COP meeting, and stated that in order to limit the damage from climate change, global temperature rise should be limited to 2°C from pre-Industrial average levels. The COP process has been successful in bringing together countries and in mobilizing scientists, non-governmental organizations (NGO's) and others to discuss climate change. However the process has been slow and has also been criticized for not being able to form a legally binding agreement accepted by all to reduce greenhouse gas emissions over time.

The 2°C Temperature Goal

The 2°C temperature limit first surfaced during a 1977 paper on Economic Growth and Climate Change written by William Nordhaus and has since become an international standard. The Cancun agreement formally recognized that parties should take action to limit temperature increase to below 2°C thereby hopefully avoiding some of the worst implications of climate change. They recognized that to achieve this goal, greenhouse gas emissions would need to be cut, which in turn has encouraged economists, scientists and engineers to identify policy scenarios that can meet this temperature increase. Thomas Stocker (the co-chair of the IPCC) has stated that, "The power of the 2°C is that it is pragmatic, simple and straightforward to understand and communicate all important elements when science is brought to policymakers".

[1] David G. Victor, 2011, Global Warming Gridlock, Cambridge University Press, UK

Why Now? The UN COP21 Meeting in Paris

From 30th November to the 11th December 2015, heads of representatives of states will once again gather, this time in Paris for the COP21 meeting. The aim of this meeting is:

1. To set up a new binding international agreement, applicable to all countries, with the aim of keeping global warming to 2°C, and

2. To mobilize funds to allow developing countries to both adapt to and mitigate climate change impacts.

COP21 provides the best opportunity to date to reach a binding international agreement on climate change

The aim is to have such an agreement in force by 2020. The difficulty of reaching a global climate agreement is due to the fact that climate change is considered a global negative externality which requires costs to be borne today, whilst the benefits would be reaped (though not explicitly felt, given that is an avoidance of an outcome) in the future.

There have been several COP meetings held before which have failed to reach an international legal binding agreement on the reduction of greenhouse gas emissions. The Kyoto Protocol that was signed in 1997 and came into force in 2005, was the closest to reaching such an objective, but still fell short of the mark. The protocol required 'Annex 1' countries (OECD countries plus countries with economies in transition) to reduce emissions by an average of 5% from 1990 levels over the five year period from 2008 to 2012 (Nordhaus, 2013)[2]. Developing countries were exempt from such targets and were only responsible for reporting their emissions over time. The protocol was an ambitious attempt to harmonize the policies in different countries, however countries did not find it economically attractive. During negotiations the US had agreed to reduce its GHG emissions, however back home the government stated that this was unachievable and abandoned the treaty completely.

The Kyoto agreement came closest, but was still flawed

There was also another problem with the treaty in that at the time of signing, the countries that agreed to the treaty emitted two thirds of the total greenhouse gas emissions; however this barely covered one-fifth of what was emitted in 2012. During the interim period, emissions grew far more rapidly in non-covered countries particularly in developing countries such as China (Victor D.G, 2011)[3]. The meeting in Copenhagen in December 2009 aimed to establish a replacement of the Kyoto Protocol, given that the limits agreed in Kyoto expired at the end of 2012. The meeting failed to achieve a binding agreement on GHG reductions amongst country participants, though they did create the Cancun agreement which recognized the scientific view of limiting temperature increase to 2°C as stated in the introduction above.

[2] Nordhaus, 2013, The Climate Casino: Risk Uncertainty and Economics for a Warming World, Yale University Press
[3] Victor, D.G. (2011)

The Clean Development Mechanisms (CDM) – Article 12 of Kyoto Protocol

Three market based mechanisms (international emissions trading and two offset programmes – Joint Implementation (JI) and Clean Development Mechanism (CDM)) were created to help developed countries meet their emission targets under the Kyoto Protocol more cost-effectively.[4] While there have been only a few projects under JI, a lot of work has gone into the CDM. CDM allows companies and Annex I countries (i.e. OECD members plus countries with economies in transition) to buy Certified Emission Reduction credits (CERs) from CDM projects in developing countries instead of reducing their own emissions. This work, driven primarily by the demand for low cost emissions reduction credits under from the EU Emissions Trading System (EU-ETS) and other countries that have ratified the Kyoto Protocol, created a global market for GHG emissions offsets. The mechanism allows investment to be targeted at the most cost-efficient emissions reductions first, wherever in the world they may be located.

According to the CDM Policy dialogue, over the past decade CDM has mobilized more than $215 billion in investments in developing countries and helped reduce 1 billion tonnes of GHG emissions.[5] However, it has also been criticized for allowing countries/companies to obtain millions of dollars in CERs for projects that they would have done anyway without the CDM in place. There has also been a problem between the balancing of supply and demand of CERs, which has decreased the price of credits over time. The uncertainty around a global agreement (the commitments under the Kyoto Protocol have expired) and the lack of demand for such credits have crippled the Clean Development Mechanism over time, although an agreement at the COP21 meeting in Paris could revive the CDM.

COP21 in Paris will be the first time countries including the big emitters have come together with positive momentum towards reducing GHG emissions

The (future) damage caused by climate change and the cost of preventing it increase over time (with even some potential points of no return), and hence time is a factor to be considered. The reason COP21 is so important is that it will be the first time that all parties (in particular some of the big emitters) have come to the table with generally positively aligned intentions, against a backdrop of an improving global economy.

21 countries and the EU have submitted pledges (INDCs) to the UNFCCC to reduce GHG emissions below a baseline level

Before the COP21 meeting, each country must publish their intended contribution to the global climate effort, a so–called 'INDC' (Intended National Determined Contribution); a new development in international climate negotiations. Shortly before the meeting, the UNFCCC secretariat will publish a summary of these contributions, to give a possible indication of the cumulative effect of all these national efforts. Twenty-one countries and the European Union (collectively covering over 56% of global greenhouse gas emissions) have submitted their INDC's at the time of writing this report, as shown in Figure 2. The EU's pledge to cut GHG emissions by 40% in 2030 compared to its 1990 level would see the region becoming one of the world's least carbon intensive economies, whilst the United States pledge would also deliver a major reduction in GHG emissions of 26 - 28% by 2025 relative to its 2005 levels. China, the largest absolute emitter of GHG emissions has echoed the statement that it made in 2014 by pledging to achieve a peak in CO_2 emissions by around 2030, an important change in direction given how its emissions have increased over recent years. It has also stated that it would cut its CO_2 emissions per unit of GDP by 60-65% from 2005 levels by 2030 and will increase its non-fossil fuel sources to about 20% by the same date.

[4] Gillenwater M, Seres S, (2011), The Clean Development Mechanism, A review of the first international offset program, Prepared for the Pew Centre on Global Climate Change.
[5] CDM Policy Dialogue (2012) Climate Change, Carbon Markets and the CDM, A call to action

Approaches are likely to be country-specific, rather than a single global carbon market

We believe that a single global carbon market is not likely to be the outcome from COP21, rather that countries will select their own approaches to meeting their INDCs. These might involve market mechanisms such as carbon pricing or energy efficiency incentives, removal of fossil fuel subsidies, various types of regulatory constraints, or some combination of these approaches. Supranational mechanisms such as the CDM (Clean Development Mechanism) or JI (Joint Implementation) might allow trading or interchangeability between these schemes.

For example, in its own INDC submission, the US points to measures to reduce emissions including regulations to cut pollution from new and existing power plants, vehicle fuel economy standards, standards to address methane emissions from landfills and the oil & gas sector, constraints on hydro fluorocarbons and codes relating to buildings, appliances and equipment.

Mobilization of Funds

$100bn per annum must be mobilized from developed to developing countries

A commitment was agreed at the Copenhagen COP meeting that developed nations (from private and public, bilateral and multilateral sources) would jointly provide $100 billion per year (from 2020) to help developing nations address climate change. A key objective of the COP21 meeting will be the mobilization of these funds, via financing, technology and capacity building. Some of this money will pass through the Green Climate Fund, which has received an initial capital of $10.2 billion from 33 governments last year (as of April 2015, 42.5% were contributions that were actually signed, the rest are pledged contributions). The purpose of the fund is to promote the shift towards low-emission and climate-resilient development pathways by providing support to developing countries to limit their greenhouse gas emissions and to adapt to climate change. The majority of the funds in the Green Climate Fund should be counted as part of the $100 billion that has been pledged, however only a certain non-predetermined part of the $100 billion will pass through the Green Climate Fund.

Figure 2. INDC Submitted by Countries/Regions

Country/ Region	INDC Pledge	Emissions (Base Year) MT CO_2e	% World GHG Emission	Mechanisms Proposed
Andorra	37% reduction in GHG emissions by 2030 from a BAU scenario.	Not applicable	Not available	
Liechtenstein	40% reduction in GHG emissions by 2030 from 1990 levels.	Not applicable	Not available	Possibility to achieve emissions reductions abroad.
Gabon	50% reduction by 2025 compared to BAU scenario.	Not applicable	0.02%	
Russia	Limiting GHG emissions to 70-75% of 1990 levels by the year 2030.	Base year 1990	4.8%	This is subject to absorbing capacity of forests.
US	26-28% reduction by 2025 compared to 2005 levels.	6135 (2005)	12.2%	Domestic legislation.
Mexico	Unconditionally reduce 25% of GHG and short lived climate pollutants emissions below 2013 levels. This could further increase to 40% subject to a global agreement.	663 in 2012- (2013 figures are not available)	1.6%	National Climate change policy.
Norway	40% reduction by 2030 compared to 1990 levels.	52 (1990)	0.06%	Collective delivery within the EU.
EU	Binding target of at least a 40% reduction by 2030 compared to 1990 levels.	5640 (1990)	8.6%	Binding legislation.
Switzerland	To reduce GHG emissions by 50% by 2030 compared to 1990 levels, corresponding to an average reduction of emissions by 35% over the period 2021-2030.	53.3 (1990)	0.1%	Switzerland will achieve its targets mainly domestically and will partly use carbon credits from international mechanisms.
Canada	To reduce GHG emissions by 30% below 2005 levels by 2030.	~730 (2005)	1.8%	Legislative instruments which includes transportation, electricity and renewable fuels regulations which encourage phasing out of coal-fired generation and stringent GHG emission standards for heavy duty vehicles.
Morocco	Two targets are proposed: an unconditional target of 13% GHG reduction and a conditional target of an additional 19% GHG reductions compared to a BAU emissions scenario in 2030.	~90(2010)	0.15%	The implementation is contingent upon gaining access to new sources of finance and enhanced support. Meeting the conditional target would require $45 billion in investment of which $35 billion is conditional upon international support such as the Green Climate Fund.
Ethiopia	To limit its net GHG emissions in 2030 to 145 MT CO_2e or lower. This means that Ethiopia is planning to reduce its GHG emissions by 64% from the BAU scenario in 2030.	Not applicable	0.30%	The full implementation of Ethiopia INDC is contingent upon a multi-lateral agreement being reached among Parties that enables Ethiopia to get international support.
Serbia	To reduce GHG emissions by 9.8% below 1990 emissions level by 2030.	Not applicable	-0.04% (0.1% w/out LUCF)	The introduction of a climate change strategy with an action plan that should be finalized in 2017 which will further define the activities, methods and implementation deadlines.
Iceland	Iceland aims to be part of a collective delivery by European countries to reach a target of 40% reduction in GHG emissions by 2030 compared to 1990 levels. A precise commitment has yet to be determined and is dependent on an agreement with the EU.	Not available	0.01%	Continue to participate in EU Emissions Trading Scheme (ETS) and to determine a target for emissions outside the EU-ETS scheme.
China	Aims to (1) achieve a peaking of CO_2 emissions by 2030, making best efforts to peak earlier; (2) to lower CO_2 emissions per unit of GDP by 60-65% from 2005 level; (3) to increase the share of non-fossil fuels in primary energy to 20% and (4) to increase the forest stock volume by 4.5 billion cubic meters on the 2005 level.	Not applicable	22.5%	Implementing of national strategies on climate change including the National Program on Climate Change (2014-2020) and to improve regional climate change policies. They will also implement measures to control total coal consumption, develop nuclear, scale up renewables and control emissions from other industry such as iron, steel etc. and from building and transport sectors.
Republic of Korea	To reduce GHG emissions by 37% from a BAU scenario by 2030.	850.6 (BAU)	1.4%	Partly use carbon credits from international market mechanisms and nationwide Emissions Trading Schemes.
New Zealand	To reduce GHG emissions to 30% below 2005 levels by 2030.	Not available	0.1%	Rests on the assumption that rules agreed by the Parties will allow for unrestricted access to global carbon markets.
Singapore	To reduce GHG emissions by 36% from 2005 levels by 2030.	40.9 (2005)	0.12%	Domestic efforts but will study the potential of international market mechanisms.
Japan	To reduce GHG emissions by 26% by 2030 compared to 2013 levels (25.4% reduction from its 2005 levels).	~1380 (2013)	2.5%	They provide detailed measures on how to reduce emissions in different sectors through efficiency improvements, better technology, energy saving standards, renewable resources, better forest management etc.
Marshall Islands	To reduce GHG emissions to 32% below 2010 levels by 2025.	Not available	<0.00001%	They identify several areas where action would be taken including efficiency improvements, electric vehicles etc. These actions depend on availability of finance and technology support.
Kenya	To abate GHG emissions by 30% by 2030 relative to a BAU scenario.	143 (BAU)	0.15%	Promotion of energy and resource efficiency, improvement of tree cover and deployment of clean energy technologies etc. This is subject to available finance, investment, technology and capacity building.
Monaco	To reduce GHG emissions by 30% and 50% by 2020 and 2030 respectively from 1990 levels.	Not available	N/A	Implementation of domestic measures and possible participation in international mechanisms.

Note: BAU = Business as Usual and LUCF = Land Use Change and Forestry, % of World GHG emissions is including LUCF and based on 2012 levels
Source: UNFCC, Citi Research

What are Greenhouse Gas Emissions?

Anthropogenic GHG emissions include CO_2, CH_4, N_2O and F-Gas; these gases cause a gradual heating of the Earth

Science appears to show that that Earth's climate is rapidly changing, as a result of an increased concentration of greenhouse gases caused by the combustion of fuels, deforestation and other human activities. These gases create a 'greenhouse effect' trapping some of the sun's energy and warming the climate in the process. The Earth has a delicate balance between the radiation it receives from space and the radiation it reflects back into space; the exchange of this radiation is known as the 'greenhouse effect'. It is this equilibrium that makes the Earth habitable, and without this equilibrium the Earth would either be too cold or too hot to live in. According to scientists, anthropogenic greenhouse gas emissions such as carbon dioxide (CO_2), Methane (CH_4), Nitrous Oxide (N_2O) and Fluorinated gases (F-Gas) act like a blanket, absorbing the sun's radiation and preventing it from escaping back into space. The net effect is a gradual heating of the Earth, a process which has been termed 'global warming'.

Carbon dioxide is emitted through the burning of fossil fuels and through a change in land-use such as deforestation. Land can also remove CO_2 from the atmosphere through reforestation, improvements in soil and other activities. Agricultural activities, waste management and the extraction and mining of fossil fuels contribute to CH_4 emissions. F-gases are emitted through industrial processes, refrigeration and the use of a variety of consumer products. Black carbon also contributes to the warming of the atmosphere though it is not a gas, rather an aerosol or a solid particle (EPA). According to the IPCC's Fifth Assessment report, concentrations of CO_2, CH_4 and N_2O have exceeded pre-Industrial average levels by about 40%, 150% and 20%, respectively.

Carbon dioxide (CO_2) makes up 76% of all GHG emissions

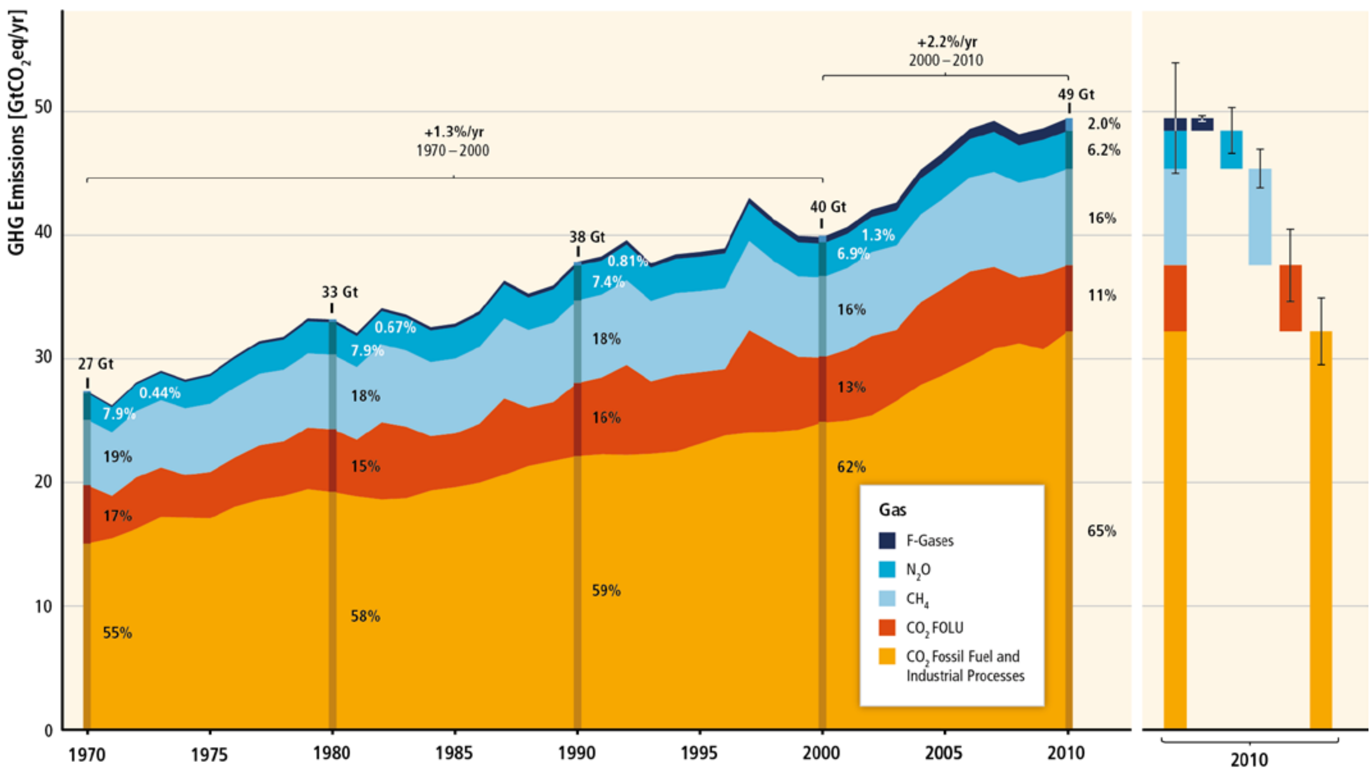
CO_2 makes up the majority of the greenhouse gas (65% from fossil fuels and other industrial processes and 11% from agriculture, forestry and other land use), followed by methane (16%) and nitrous oxide (6.2%). The effect of each gas on climate change depends on three main factors:

1. The concentration or abundance of the gas found in the atmosphere
2. How long it stays in the atmosphere, and
3. How strongly it impacts global temperatures, as some gases are more effective at warming the planet than others.

For each greenhouse gas, a global warming potential has been calculated, reflecting a combination of the second and third factors above by the US Environment Protection Agency[6], to allow a comparison of the contribution of each gas.

[6] US EPA, Overview of Greenhouse Gases
www.epa.gov/climatechange/ghgemissions/gases.html

Figure 3. Total Annual Anthropogenic GHG Emissions By Groups of Gases, 1970-2010



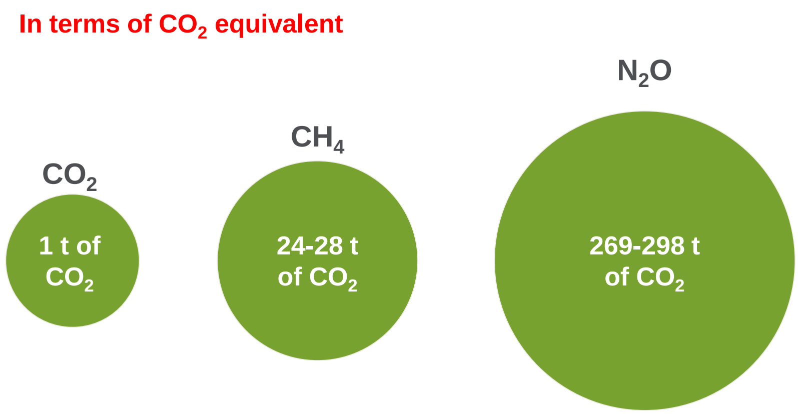
Source: : IPCC (2014)

Global Warming Potential

Global Warming Potential (GWP) was developed to allow comparisons of the global warming impacts of different gases. It is a measure of how much energy the emissions of one tonne of a gas will absorb over a given period of time (usually 100 years), relative to the emissions of one tonne of carbon dioxide. The larger the GWP, the more that gas warms the Earth compared to CO_2 over the given time period.[7] It provides a common unit of measure, which allows scientists to compile national greenhouse gas inventories and compare emissions-reduction opportunities across sectors and gases. Based on GWP calculations, 1 tonne of methane is approximately 28-34 times more effective at warming the atmosphere than carbon dioxide, whilst one tonne of nitrous oxide is 265-298 times more effective at warming the atmosphere than carbon dioxide. However carbon dioxide is the largest anthropogenic greenhouse gas (~76% in 2010) and remains in the atmosphere for a very long time, whilst methane (~16% in 2010) and nitrous oxide (~6% in 2010) emitted today will remain in the atmosphere for a decade and 100 years respectively.

[7] US EPA, Understanding Global Warming Potentials www.epa.gov/climatechange/ghgemissions/gwps.html

Figure 4. Carbon Dioxide Equivalents for Different GHGs



Source: Citi Research

Energy-Related CO_2 Emissions

2/3 of all GHG emissions are emitted by the energy sector

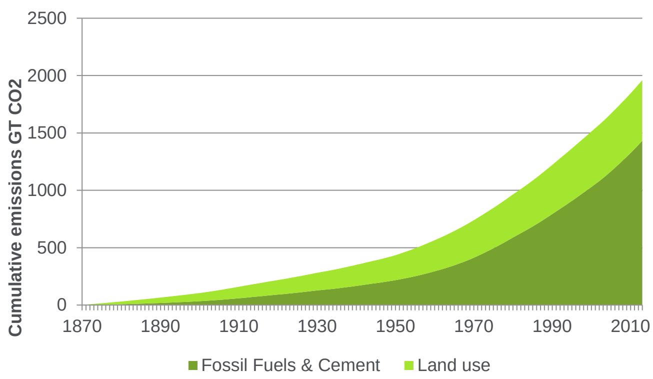
The energy sector contributes two thirds of greenhouse gas emissions, the rest being attributed to land use and forestry and other industrial processes. 90% of the energy-related emissions are CO_2 from fossil fuel combustion, with methane from oil and gas extraction, transformation and distribution accounting for just under 10%. The remainder are nitrous oxide emissions from energy transformation, industry, transport and buildings.

The Energy sector is responsible for 73% of cumulative CO_2 emissions

Since CO_2 emissions accumulate in the atmosphere over time, it is important to look at both cumulative and annual emissions. Figure 5 shows the cumulative CO_2 emissions from 1870 to 2013 from both energy and land use. The energy sector contributed 73% of these emissions, with the rest being attributed to a change in land use and agricultural practices. Figure 6 shows the annual CO_2 emissions from energy and land use from 1959 to 2013 together with the carbon sinks, i.e. natural 'reservoirs' which remove carbon from the atmosphere. Annual CO_2 emissions from fossil fuels (and cement) increased from an estimated 6GT in 1950 to 36GT of CO_2 in 2013. According to the International Energy Agency (IEA), CO_2 emissions stalled in 2014, unchanged from 2013, despite the global economy increasing by approximately 3% in the same year; potentially marking an important delinking (or the start of one) between CO_2 and GDP.

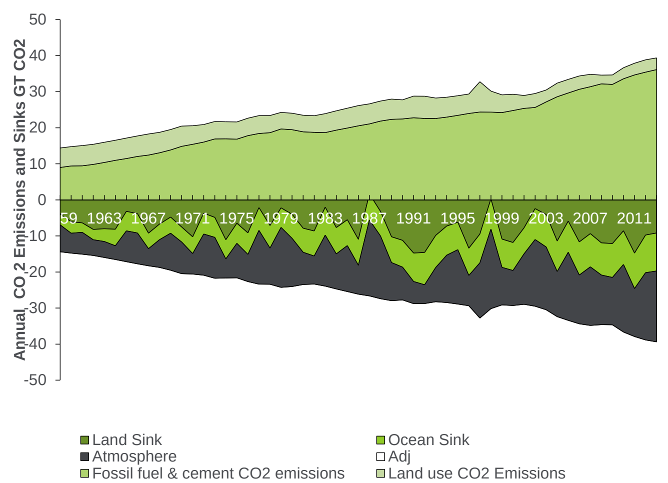
The oceans, land and atmosphere are the three main sinks for carbon dioxide and as we emit more carbon dioxide each year, each of the three sinks absorb more carbon. If it wasn't for land and ocean sinks, annual carbon dioxide concentrations would be accumulating in the atmosphere at a higher rate. Although we tend to focus on growing atmospheric carbon concentrations, ocean acidification (the ongoing decrease in the pH of the Earth's oceans caused by the uptake of carbon dioxide from the atmosphere) also has potentially serious ramifications.

Figure 5. Cumulative CO_2 Emissions from Energy and Land Use



Source: Bodel et al. (2013), Houghton et al. (2012), Citi Research

Figure 6. Annual CO_2 Emissions from Energy and Land Use and Carbon Sinks



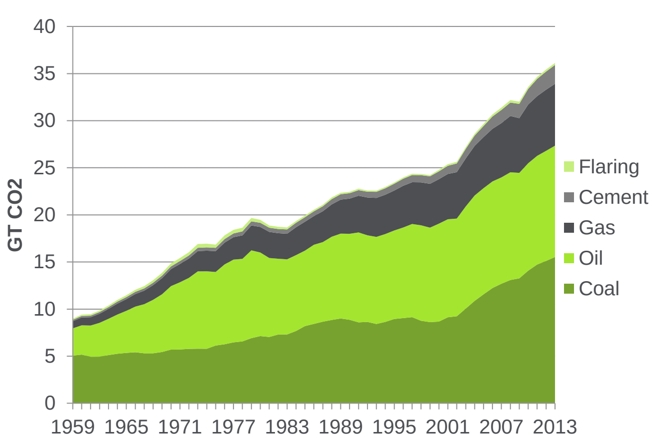
Source: Bodel et al. (2013), Houghton et al. (2012), Tans and Dlugokenckys, Le Quéré et al. (2013), Citi Research

Energy-Related CO_2 Emissions by Fuel and Sector

The electricity and heat sector was the largest emitter of energy-related CO_2 emissions

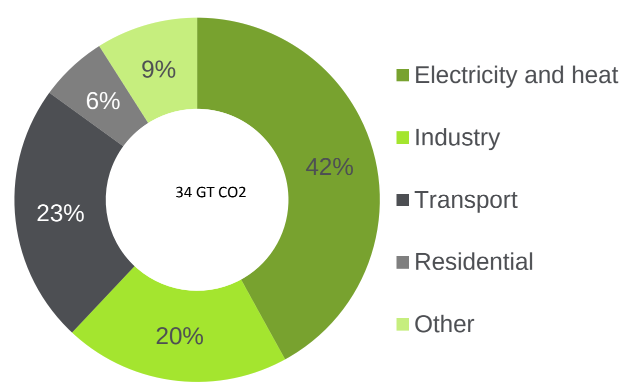
Although coal only represents 30% of total primary energy supply, it accounted for 43% of energy-related CO_2 emissions in 2013 due to its heavy carbon content per unit of energy released. Compared to gas, coal is on average nearly twice as emission intensive. Oil and gas contributed 33% and 18% of emissions respectively in 2013 (Figure 7). Figure 8 shows that the electricity and heat sector was responsible for 42% of energy-related CO_2 emissions, followed by the transport sector (23%) and industrial sector (20%). Over 40% of the generation of electricity and heat worldwide relies on coal; in fact countries such as Australia, China and India produce over two thirds of their electricity and heat through the combustion of coal. However, as renewables are becoming cheaper, they could replace some of the coal consumption in future years.[8]

Figure 7. Annual Energy-Related CO_2 Emissions by Fuel Type (includes cement)



Source: Boden et al. (2013), Houghton et al. (2012), Citi Research

Figure 8. % of Annual Energy-Related Emissions by Sector



Source: IEA (2014), Citi Research

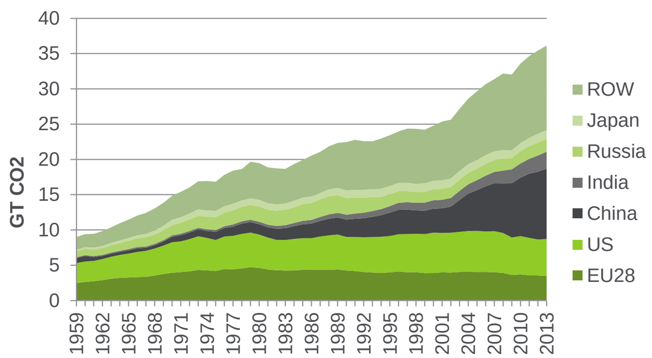
[8] BP Energy Outlook. 2035. www.bp.com/energyoulook

Energy-Related CO_2 Emissions by Country

In 2013 China was the largest emitter of CO_2, however on a cumulative basis the US has been the largest CO_2 emitter

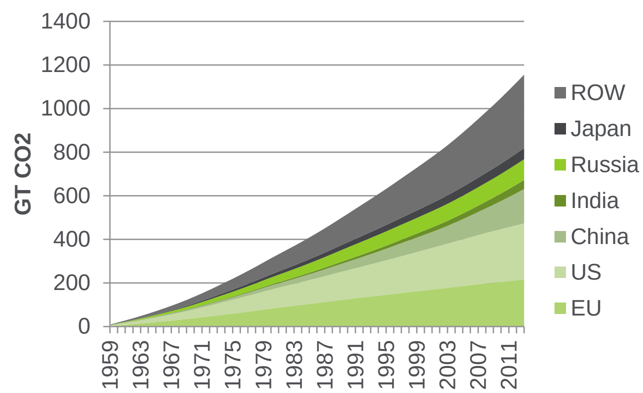
In 2013, China was responsible for emitting over 27% of total energy-related CO_2 emissions, followed by the US (14%) and the EU (9%). Figure 9 below shows the dramatic increase in China's energy-related CO_2 emissions between 2002 and 2013. Cumulative CO_2 emissions from 1959 to 2013 (Figure 10), show a different picture, with the US responsible for emitting 22% of total emissions, followed by the EU (19%) and then China (14%). China in its INDC has pledged to peak its CO_2 emissions by around 2030, and intends to increase the share of non-fossil fuels in primary energy consumption to around 20% by 2030. An indirect benefit of reducing emissions is a reduction in air pollution (a major issue in China's cities) especially from coal-fired plants, which is driving China to close inefficient coal plants and increase its share of nuclear and renewables.

Figure 9. Annual Energy-Related Emissions by Country (incl. cement)



Source: Boden et al. (2013), Houghton et al. (2012), Citi Research

Figure 10. Cumulative Energy-Related Emissions by Country

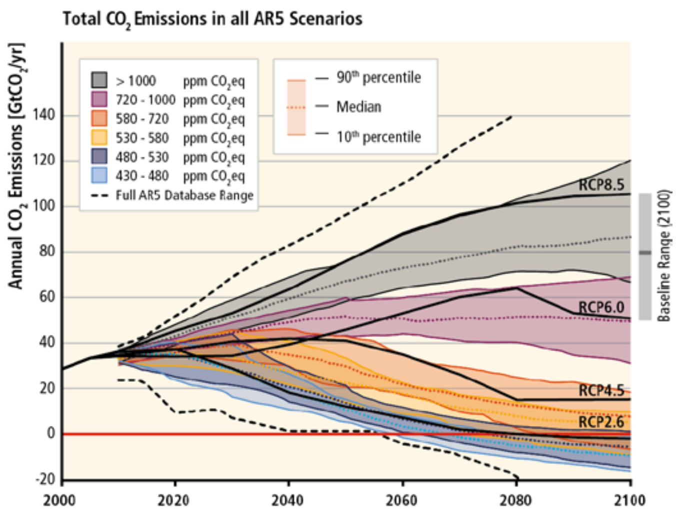


Source: Boden et al. (2013), Houghton et al. (2012), Citi Research

Future Emissions and the 'Carbon Budget'

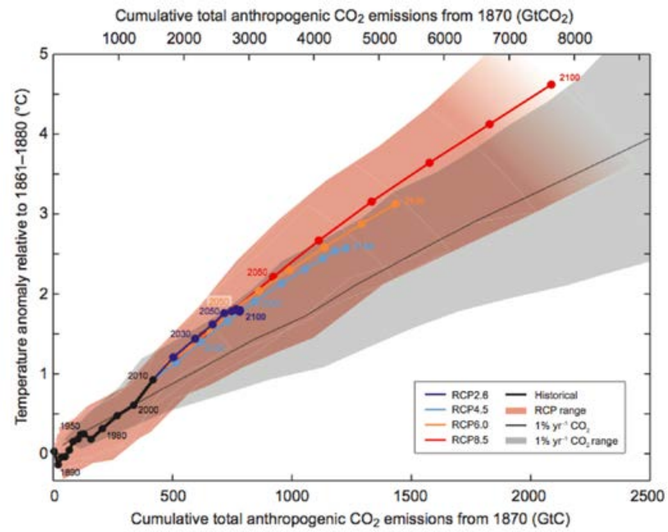
Climate scientists use a vast array of monitoring data to create models that reproduce the mechanisms of the climate system. To calculate how human activities could affect the climate, scientists take into account greenhouse gas concentrations, pollution and changes in land use in their models. These concentrations and changes depend on future social and economic development including things such as economic growth, technological change, population growth, innovation etc. Scenarios are therefore used to explore these issues in more detail. The IPCC in their last report identified four new scenario's called Representative Concentration Pathways (RCP's). These four RCPs include one mitigation scenario (RCP 2.6), two stabilization scenarios (RCP 4.5 and 6), and one scenario with very high greenhouse gas emissions (RCP8.5). Figure 11 and Figure 12 show the annual and cumulative CO_2 emissions respectively under these RCP scenarios.

Figure 11. Annual CO_2 emissions under RCP scenarios



Source: Clarke et al. (2014)

Figure 12. Cumulative CO_2 emissions under RCP scenarios



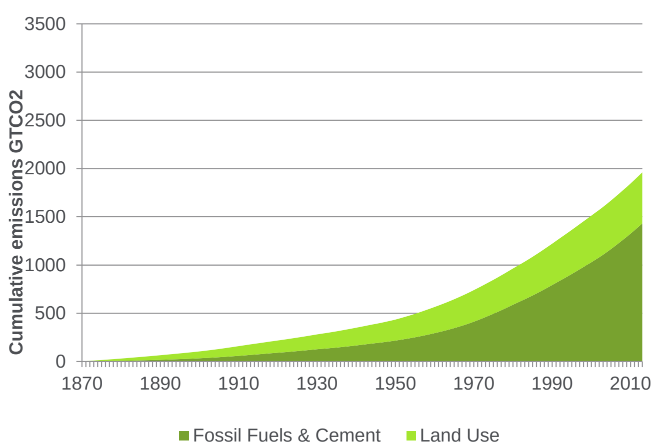
Source: IPCC, 2013

The Carbon Budget

We have already emitted over 60% of the total 'carbon budget', and therefore we have little room to expand if we want to limit warming to 2°C.

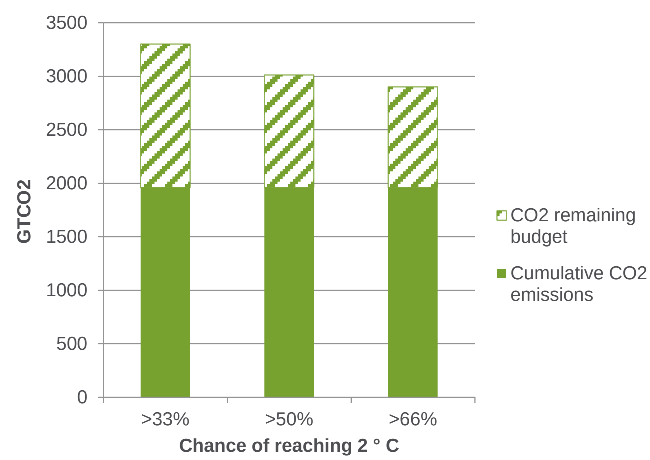
The RCP 2.6 scenario creates a pathway designed to offer a 50% chance of limiting global temperature increases to 2°C. To reach this target, greenhouse gas emission concentrations in the atmosphere would need to stabilize to about 445 to 490 ppm CO_2 equivalent. Ultimately this means that global cumulative CO_2 emissions would need to be limited to approximately 3,010GT CO_2 (IPCC, 2014), the so-called 'carbon budget'. Figure 13 and Figure 14 below show that we have already emitted more than 60% of the total 'carbon budget', leaving little room to expand CO_2 emissions if we are serious in wanting to limit temperature increases to 2°C.

Figure 13. Cumulative CO_2 Emissions from 1870 to 2013 in Comparison with the 'Carbon Budget'



Source: Boden et al. (2013), Houghton et al. (2012), Citi Research

Figure 14. Global 'Carbon Budget'



Source: IPCC (2013)

What Happens if We Don't Meet the 'Carbon Budget'?

While the impacts of climate change are very difficult to define with any certainty, key negative impacts include:

- A reduction in crop productivity which would have an impact on global food production.
- A reduction or increase in the availability of water resources (e.g. floods and drought).
- Sea-level rises which could affect coastal cities.
- Potentially the extinction of certain species.

This list is far from exhaustive, and it is perhaps more sobering to consider it in terms of associated human consequences, for example famine, drought, associated health issues, mortality rates and mass population displacement to name but a few.

The aim of the COP21 meeting in Paris is to finalize a legal binding agreement between all countries to reduce greenhouse gas emissions over time, thereby increasing the chance of limiting temperature increases to 2°C. The 'carbon budget' aims to provide an simple metric which world leaders could agree to, and against which aggregated INDC's could be compared.

Action vs. Inaction: Counting the Cost of our Energy Choices

Highlights

- Almost one fifth of the world's population still lack of access to power, with 40% lacking access to clean cooking facilities. Global GDP is expected to treble by 2060, with two thirds of that growth coming from non-OECD countries. This GDP growth and increasing wealth levels will require vast amounts of energy.
- Emerging markets show significantly higher levels of energy intensity (units of energy used per unit of GDP) as they industrialize, and higher carbon intensity i.e. they emit more carbon per unit of GDP (and per capita), as they tend to use the cheapest, most readily available forms of power, which are often the 'dirtiest'.
- With most of the global GDP growth coming from emerging markets, a disproportionate amount of energy will be required, resulting in disproportionately higher emissions.
- Given the potential impact of emissions, the world is faced with an energy choice – either Action (mitigation or geoengineering) or Inaction (adaption) on climate change. These are examined in greater in detail in the chapters that follow.
- The likely total spend on energy (capex and fuel) over the next 25 years is actually remarkably similar on both an Action and Inaction scenarios — Citi's 'Action' scenario implies a total spend on energy of $190.2 trillion while our 'Inaction' scenario is actually marginally larger at $192 trillion.
- While in the Action scenario we spend considerably more on renewables (reducing in cost over time) and energy efficiency (effectively negative energy usage), the resulting lower use of fossil fuels lowers the total cost in later years.

Our Energy Choices

The world is faced with difficult, but enormously important choices about its energy future. Global primary energy demand is likely to grow by more than 30% over the next 20 years and how we adapt that demand given its linkage with GDP, and how we feed that hunger for energy will have enormous consequences for countries, economies, industries, and the world as a whole. While there are countless smaller decisions that will follow with either path, the choice can essentially be broken down into two paths:

We compare two scenarios – Inaction and Action and examine the effect these choices could have on global GDP and investment opportunities

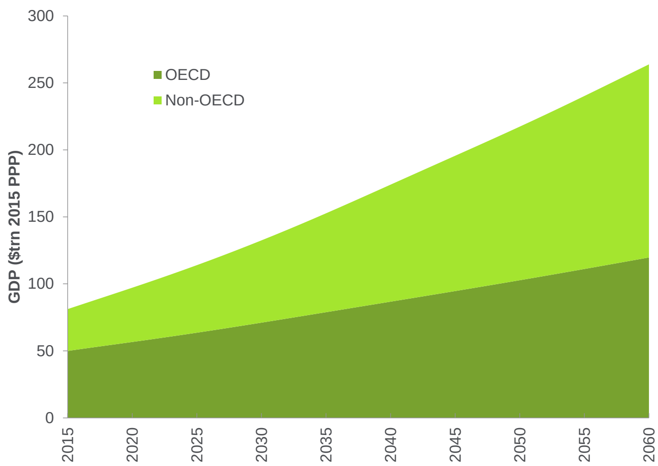
1. **Inaction** – We allow macroeconomics to drive demand for energy by ignoring the implications for emissions and feeding energy demand based purely on (often short term) economics and the immediate availability of fuel. To meet rapidly growing energy demand, this scenario will result in an enormous 'energy bill' for the world, and alongside this we must also consider the potential financial implications of climate change.
2. **Action** – We mold our energy future driven by a blend of emissions, economics, avoided costs and the implications of climate change. This requires an assessment of how much 'extra' we will spend on transforming the global energy mix to a low carbon energy complex, and what the other associated costs will be in terms of lost global GDP, stranded assets etc., offset against the avoided costs of climate change.

An Energy Hungry Planet

The IEA estimates that currently 1.3 billion people or 18% of the world's population do not have access to electricity, and 2.6 billion people (40%) lack access to clean cooking facilities. As wealth levels increase and the global economy develops, global energy demand is set to balloon over the coming decades, and the backdrop of its impact on the climate makes the choice of how that energy is generated, and indeed how much of it we use versus how much we save, of critical importance.

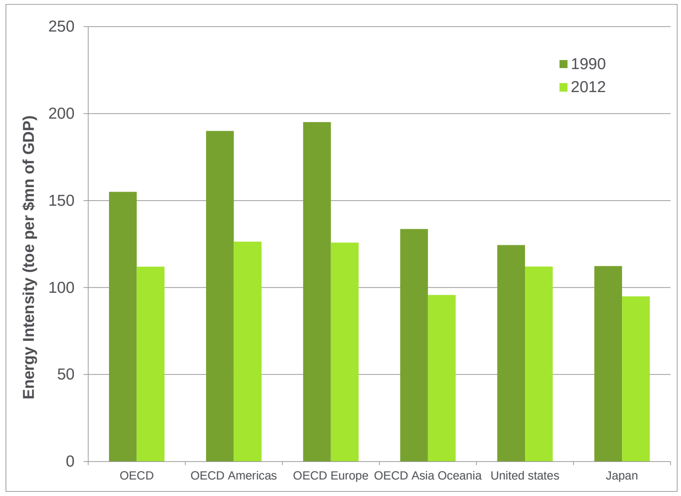
As Figure 15 shows, global GDP is set to increase from around $80 trillion today to around $260 trillion by 2060 (at current prices) — a threefold increase. Two thirds of that growth is scheduled to come from non-OECD economies.

Figure 15. Global GDP Growth Projections 2010-2060 by OECD and Non-OECD Grouping (Current Pricing)



Source: OECD, Citi Research

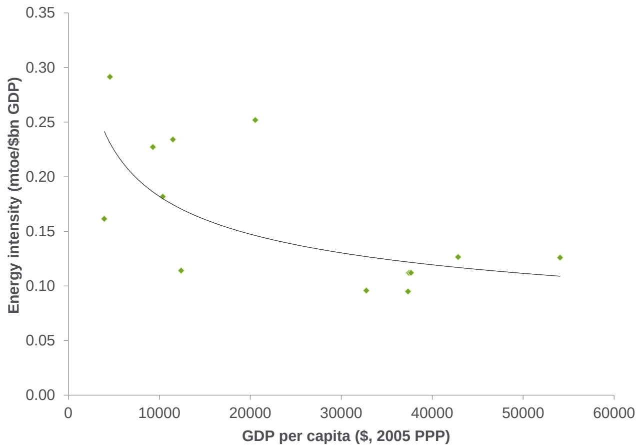
Figure 16. Energy Intensity Reduces Over Time as Nations Become More Wealthy



Source: OECD, IEA, Citi Research

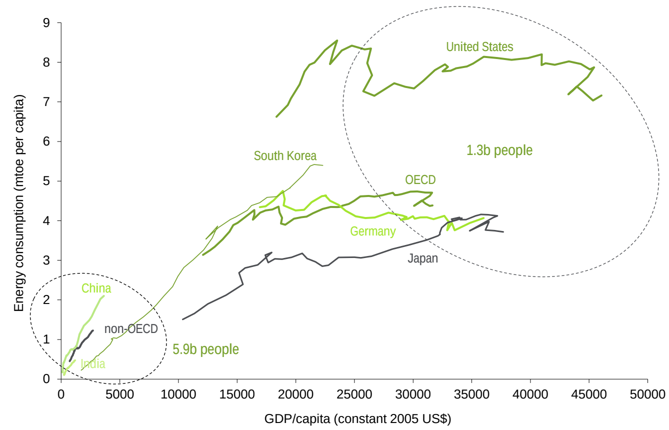
This GDP growth will require enormous quantities of energy, which is particularly pertinent when we consider that emerging economies show significantly greater levels of energy intensity, i.e. the amount of energy used per unit of GDP generated. The good news, as Figure 17 and Figure 18 show, is that as nations become wealthier, i.e. GDP per capita increases, energy intensity reduces mainly as these nations move towards a more service-based economy and become less focused on manufacturing, but also as efficiency increases.

Figure 17. Energy Intensity Reduces with Increasing GDP Per Capita



Source: OECD, IEA, Citi Research

Figure 18. Energy Consumption Per Capita Reduces as Wealth Increases



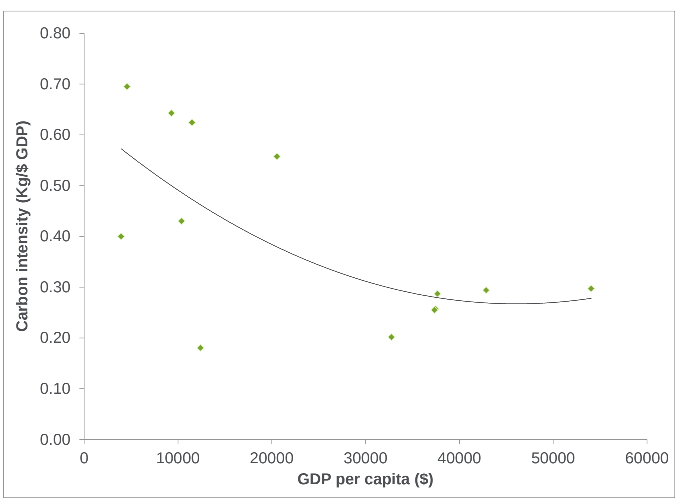
Source: OECD, BP, Citi Research

2/3rds of economic growth will come from emerging markets, which show higher levels of energy and carbon intensity per unit of GDP

Although a reduction in energy intensity is good news, the fact is that two thirds of global economic growth will come from emerging markets, which will require disproportionate amounts of energy to achieve that growth.

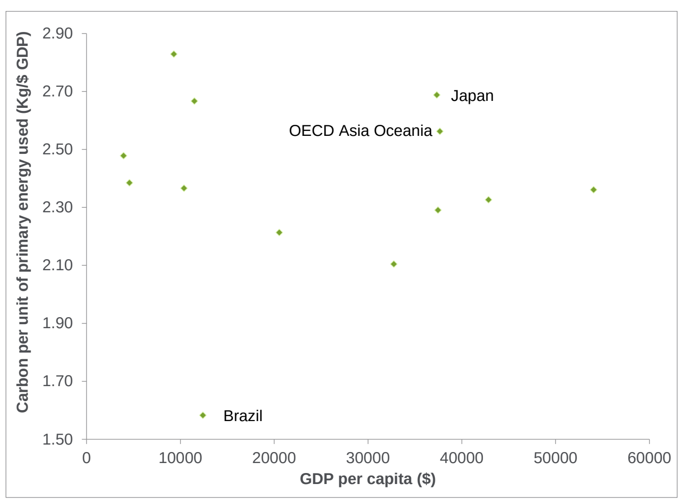
To add fuel to the fire, so to speak, emerging economies are often so power hungry trying to keep up with growth that there is a natural tendency to go for the cheapest, most quickly deployable forms of energy available (i.e. coal) which are often the 'dirtiest' in terms of emissions. This is not true across the board, as some developing economies have high proportions of hydropower (Brazil), while other developed nations which are blessed with significant fossil natural resources remain relatively high emitters (see Figure 20). However, this general truism combined with the higher levels of emerging market energy intensity mean that developing markets emit significantly larger quantities of CO_2 per unit of GDP generated than developed economies, as shown in Figure 19.

Figure 19. Carbon Intensity vs GDP Per Capita; Carbon Intensity Reduces with Increasing Wealth Levels



Source: OECD, IEA, Citi Research

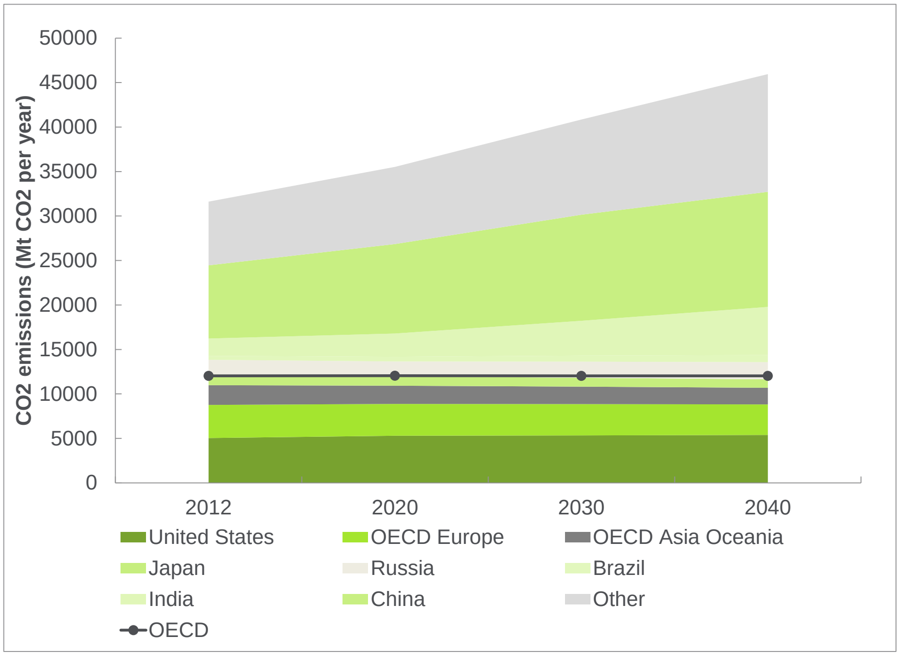
Figure 20. Emerging Markets Typically Use 'Dirtier' Fuels, though 2012 Trend is Skewed by Japan in the Wake of Fukushima



Source: OECD, IEA. Citi Research

More limited GDP growth with lower energy and carbon intensity in developed markets, combined with faster GDP growth and greater energy and carbon intensity in emerging markets, means that under current scenarios, carbon emissions would rise significantly in the coming decades, with effectively all of the growth in emissions coming from emerging or developing markets, as shown in Figure 21.

Figure 21. CO_2 Emissions by Country/Region Under 'Business as Usual' Scenario



Source: IEA, Citi Research

The Choice of Energy Path

There are three ways to reduce GHG emissions — adaption, geoengineering and mitigation, or a combination of the three. We concentrate on mitigation efforts to reduce energy-related emissions

The good news is that although close, we are not yet committed to the path of much higher emissions. There are three main ways that we can deal with the threat of climate change[9]:

- **Geoengineering:** Consists of a wide range of proposed methods of cooling the planet – some involve reflecting a portion of the sun's radiation back into space and others involve removing carbon dioxide from the atmosphere. It is an extremely complex subject and it is unclear if any of the proposed techniques are technically feasible, environmentally sound and socially acceptable. Given the infancy of this field, we have not examined this approach in detail, though would note that this is an area worthy of exploration potentially as part of our suggested increase in global R&D (discussed in chapter 'Making It Happen').

- **Adaptation:** Involves learning to cope with a warmer world rather than trying to prevent it. It is effectively a 'business as usual' approach, the costs and effects of which are examined in the chapters 'The Cost of Inaction' and under our Citi 'Inaction' scenario. Costs are likely to be significant, not just in terms of lost GDP, population displacement, agriculture etc., but in terms of the enormous investments required in infrastructure such as flood defenses. It is this latter area of costs — i.e. the costs of learning to live with a warmer climate — which are traditionally referred to as the costs of adaptation.

[9] Nordhaus (2013).

- **Mitigation:** Consists of action to reduce greenhouse gas emissions. In this report we concentrate on mitigation and the investment required in the energy sector for it to play its part in limiting warming to below 2°C relative to pre-Industrial levels, largely as this is easier to quantify with an associated greater level of certainty (though even this is still highly speculative).

Significant efforts to mitigate climate change can reduce the need for adaptation and the need for geoengineering, but one should not dismiss these other approaches completely, as global warming results from the accumulation of past long-lived GHG emissions, and therefore just reducing current GHG emissions might not be enough to reach a 2°C temperature increase limit. These approaches are therefore not mutually exclusive strategies, rather having synergies that can be exploited to enhance their cost-effectiveness.

We examine each of these options in turn over the following chapters

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Geoengineering

Mitigation is not enough. In order to achieve the climate policy goal of restricting the rise in global mean temperatures to less than 2°C above pre-Industrial levels will require some form of geoengineering.

Geoengineering is an umbrella term that covers a wide range of proposed techniques to counter climate change by deliberate large-scale interventions in the Earth's system. There are two main classes of techniques – Solar Radiation Management (SRM) and Greenhouse Gas Removal (GGR).

SRM involves reflecting a small proportion of the sun's radiation back into space. This could be achieved by introducing droplets of sulphuric acid into the upper atmosphere, which would act as tiny mirrors, or by brightening clouds. Such techniques could be fast-acting, cooling the planet quickly and could be cheap to deploy (compared to conventional mitigation), but the governance challenges of deploying such a technique would be immense and it would provide only a temporary fix. If you cease SRM, the temperature would bounce back up to where it would have been previously and if the level of greenhouse gases in the atmosphere is still increasing that bounce back would be extremely rapid and harmful. This so-called Termination Effect could in fact be terminal.

GGR involves removing CO_2 and other greenhouse gases from the atmosphere and storing them away so that they no longer affect the climate. This could be achieved by planting more forests or by developing machines that extract CO_2 from the atmosphere. All such techniques are likely to be expensive, but could provide a permanent fix. The governance challenges vary depending on technique, but in the main are likely to be less onerous than those associated with SRM.

You may not like the sound of geoengineering, but it is already assumed in the climate models that avoid dangerous climate change. The IPCC's RCP2.6 scenario is the only one that caps temperature rises below 2°C, but this is achieved only by assuming that emissions turn negative in the second half of this century – that GGR techniques will be deployed at a multi-billion tonne per year scale. There is a central incoherence in policymakers' efforts to avoid dangerous climate change — no such techniques exist and there is inadequate funding for research or incentives for industry to invest in developing such techniques. They seem to be willing the ends without providing the means.

Adaption: The Costs of Inaction

Highlights

- While the cost of adaption traditionally refers to the cost of living with climate change, such as increased spend on flood defenses, here we examine the additional costs to the world in terms of its impact on GDP.
- Climate change will have an impact on global GDP, and hence there is effectively a cost of inaction. Climate scientists use so-called "Integrated Assessment Models" (IAM's) to estimate these impacts and costs.
- These IAM's produce a wide range of expected impacts, the range of estimates being between 0.7% to 2.5% of GDP for a temperature increase of 2.5°C which is expected to be reached in 2060
- The cumulative losses to global GDP from climate change impacts ('Inaction') from 2015 to 2060 are estimated at $2 trillion to $72 trillion depending on the discount rate and scenario used. Lower discount rates encourage early action.
- If emissions continue to rise and therefore temperature continues to increase after 2060, the negative effect on GDP losses could become more than 3% of GDP with estimates ranging from 1.5% to almost 5%.
- Under an 'Inaction' scenario, the world would be locked to a high-emissions infrastructure and the damages could continue for more than a century.
- The highest impacts of GDP are foreseen in South and South East Asia, Africa and the Middle East.
- The estimated damages could be larger as these economic studies only measure those impacts that are quantifiable and largely concentrate on market or near market sectors. Other impacts such as tipping points, weather related events or catastrophic risks are not included in the studies.

Introduction

While 'global warming' is a general description of the potential effects, scientists believe that the biggest effects from climate change will actually be changes in rainfall patterns, ocean currents, growing seasons and everything else that depends on climate[10]. The impacts of climate change differ between one region and the next, with some regions likely to experience more frequent droughts, whilst others experience an increase in rainfall and potentially flooding. This could affect the availability and affordability of food and water, significantly impact poverty levels, health, mortality rates, and ultimately drive sizeable population displacement with all its associated implications.

Accordingly if the scientists are correct, the impacts of climate change could be significant, and would affect all of us. In economic terms, while little would remain unaffected, the sectors most obviously impacted by climate change include the energy, water, agriculture/food/fishery, and health sectors, not forgetting the insurance sector and banking/financial markets generally.

[10] Victor (2011)

The Cost of 'Inaction' on Global GDP

There have been several studies that have estimated the impact climate change could have on the global economy. Integrated Assessment Models (IAMs) are mostly used to calculate these damages as described in the box below. It is important to note that these welfare studies use different methods and different assumptions, which makes comparing them particularly difficult.

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Climate Economics - Integrated Assessment Models

Should climate action be more or less ambitious? What are the various advantages and disadvantages of different policy interventions? Who can, should and will pay? How ought the inherent risk and ambiguity be evaluated? What is the so-called social cost of carbon?

A standard and influential tool used by economists to answer these questions is the Integrated Assessment Model (IAM). There are different types of IAMs, but the types most commonly used by economists start with a baseline economic scenario that incorporates an assumed level of emissions. The models then consider the costs and benefits, at the margin, of reducing emissions to limit the damages that might result from climate change. In other words, the marginal costs of abating a tonne of carbon dioxide emissions are estimated and compared with estimates of the marginal social damage inflicted by that tonne. The latter is also referred to as the 'social cost of carbon' (SCC).

Policymakers are naturally interested in a single point estimate for the SCC that they can apply in government policy. However, there is a real risk that such a single point estimate is misleading. There is so much uncertainty that any single point estimate implies a false precision, as discussed below. Moreover, any estimate of social costs requires making choices that are ethically contentious, also discussed below under point two. Finally, the models used almost inevitably omit key considerations, implying that the point estimates may themselves be biased, as noted in section 3.

Nevertheless, such numbers are estimated and used. For instance, the United States Office of Management and Budget (OMB) and the EPA have conducted a joint analysis of the appropriate social cost of carbon for use in government policy, deriving a value of $37/t CO_2 (as of June 2015). This commentary considers the three key points to bear in mind when interpreting and using SCC estimates.

1. Scientific uncertainty about specific climate impacts

While the relationship between carbon dioxide emissions and increases in global mean temperatures are now fairly well understood, the uncertainty over the specific impacts in specific places at specific times remains substantial. Economists have, primarily for convenience, proxied the relationship between aggregate damages and temperature with a simple damages function. This expresses the fraction of GDP lost in a given year due to the relevant increase in temperature. Damages are often assumed, for convenience, to be a quadratic function of temperature increase. So it is assumed that damages increase smoothly as temperatures rise, with no abrupt shifts. There are, of course, other possible damages functions, and the evidence from the physical sciences suggests that functions with thresholds and triggers are far from ruled out.

Analysis of IAMs suggests that the carbon price can vary quite strongly on the specific response of ecosystems to temperature rises. As just one example, modelling by Ceronsky et al with FUND, a fairly standard IAM, suggests that if the thermohaline circulation (THC) were to shut down, the corresponding social cost of carbon (SCC) could increase to as much as $1,000/t CO_2. In short, the applicable social cost of carbon is very difficult to pin down because of the wide array of risks that could occur from our meddling with the climate system.

2. Value judgments cannot be avoided

Even if we were able to isolate and eliminate all scientific uncertainties in the chain of linkages between emissions, concentrations, temperatures and economic impacts, it would remain impossible to specify a single 'correct' estimate for the social cost of carbon. This is because a range of unavoidable social value judgments must be made in order to derive any estimate. These value judgments arise in a range of areas, but the four most contentious and important relate to valuing:

- **Impacts on future people**: The weight placed on impacts in the distant future, compared to impacts today, is reflected in the discount rate. This was one of the most contested parameters following the publication of the Stern Review, which used lower discount rates than previous studies, and in part for that reason concluded that the social cost of carbon was substantially higher.
- **Risk preferences**: Value judgments about risk preference are important too, given the risks involved in allowing the Earth's climate to heat. Higher aversion to risk tends to imply a higher social cost of carbon.
- **Inequality preferences**: It is expected that the impacts of climate change will fall more harshly upon the poor than the rich. How to value these effects strongly depends upon the assumed aversion to inequality.
- **Human lives**: Because climate change is expected to lead to a large number of deaths, the monetary valuation of a human life, if used, comprises a significant uncertainty in the overall estimate of the social cost of carbon.

These various value judgments have been debated at length by the economists and philosophers who work on the integrated assessment modelling of climate change. Now is not the place to rehearse those arguments in detail. However, it is worth noting that the use of market prices and market data – such as using market interest rates for government bonds as a proxy for the social discount rate – does not avoid these philosophical questions. The very decision to use the market is itself a (contested) philosophical choice.

3. Omission bias may lead to misleadingly low estimates

Finally, just as important as the scientific uncertainty and the inevitably of value judgments in SCC estimates is the concern that estimates emerging from economic IAMs may be systematically biased. The main source of concern is that, by definition, IAMs only model the effects that they are capable of modelling. The implication is that a wide range of impacts that are uncertain or difficult to quantify are omitted. It is likely that many of these impacts carry negative consequences. Indeed, some of the omitted impacts may involve very significant negative consequences, including ecosystem collapse or extreme events such as the catastrophic risks of irreversible melting of the Greenland ice sheet with the resulting sea level rise. Other consequences – such as cultural and biodiversity loss – are simply very difficult to quantify and are hence just omitted. While it is also likely that some omitted climate impacts are positive, it is highly probable that on balance such omitted impacts are strongly negative, leading to SCC estimates that are systematically too low and corresponding policy on climate change to be too weak. Indeed, the United Nations' IPCC assessment reports themselves accept that their own estimates should be viewed as being conservative, consistent with the prevailing culture of scientific enquiry.

Conclusion

Some scholars have concluded that given these limitations, IAMs are damaging or, at best, useless. It should certainly be openly and loudly acknowledged that estimates of the social cost of carbon are highly uncertain, subjective and potentially biased. Estimates should be accompanied with a corresponding warning of these weaknesses and advice to take any particular estimate with a grain of salt.

But not having models is not a solution either. Ignoring the intellectual challenges that are intrinsic to the economics of climate change does not make them vanish. Instead, economists need to do better, with much more transparent models – where value judgments and uncertainties are clear and can be played around with by policymakers and the general public – and where wide ranges are employed to communicate the sensitivities involved.

Along with transparency, a new generation of IAMs could focus our attention in more useful directions, away from short-term marginal changes and instead towards systemic, transformational change. This, rather than devising policy to balance central estimates of the social cost of carbon and central estimates of abatement costs, it may be better to seek interventions aimed at two objectives: (i) reducing the probabilities of very bad outcomes to very low levels, even if this involves relatively high cost; and (ii) increasing the probabilities of a positive transformational 'surprise' – for instance a cost breakthrough in clean technology – that could deliver very large social gains.

Determining a central estimate of the SCC does not prevent thinking about transformational change. However, an exclusive focus on the mean SCC tends to direct policy towards a set of interventions involving marginal, incremental changes to the existing system. Given the risks, and the potential benefits of a transition, incremental change is clearly far from enough. Instead, IAMs ought to help decision makers to consider major disruptive change. Far from being 'in the tails of the distribution', disruptive changes to our natural ecosystems and to our industrial ecosystems are now almost inevitable.

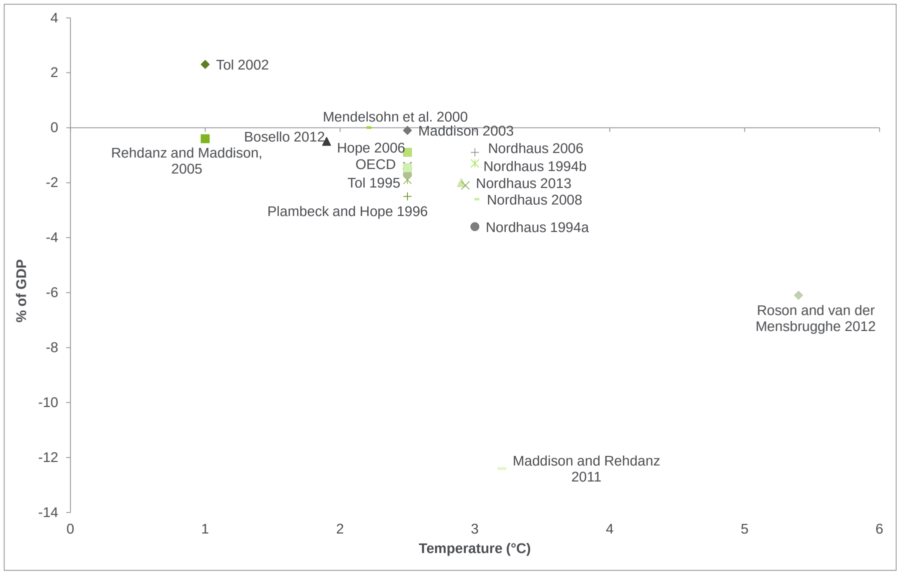
Generating an Aggregated View of IAM's

Of the many studies that have been written estimating the impact climate change could have on the global economy, one of the best known is 'The Economics of Climate Change' written by Lord Stern in 2006 which famously became known as the Stern Review. The main conclusion from the report was that that if we don't act now the overall costs and risks of climate change would be equivalent to losing at least 5% of global GDP each year 'now and forever' or 11% when one includes a rough estimate for other externalities such health and environmental effects that do not have market prices. Some of the impacts of climate change include access to water, food, health and the use of land and the environment. For example, a decline in crop yields especially in places like Africa could have a profound effect on future food production; ocean acidification as a direct result of increasing CO_2 emissions could impact marine ecosystems with possible effects on fisheries, whilst rising sea levels could result in millions of people being flooded each year due to an increase of warming of 3 or 4°C. Small islands in the Pacific and Caribbean and large coastal cities such as Shanghai could all be affected by sea-level rise.

Climate economists agree that an increase in temperature would have a negative effect on global GDP

Stern has been criticized by academics amongst other things for his use of a low discount rate (average 1.4%) — a topic which is much discussed in climate change economics. Other studies have also been undertaken to assess the aggregate damages from climate change for different levels of warming. The majority of these studies agree in principle that an increase in temperature would have an impact on the global economy ranging from 0.9 to 2.5% of global GDP loss for a temperature increase of 2.5°C. This loss increases to 6.4% for a temperature increase of over 5°C (refer to Figure 22 below). These costs are not one-time but are rather incurred year after year because of permanent damage caused by increased climate change

Figure 22. Aggregate Estimated Potential Climate Change Damages to Global GDP



Source: Arent et al. 2014[11] Citi Research

Global GDP losses from climate change inaction are estimated from 0.7% to 2.5% in 2060.

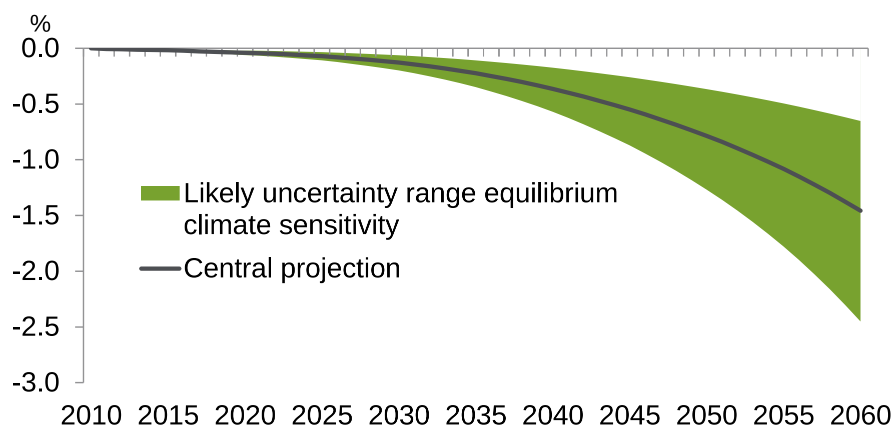
The OECD estimates that global GDP losses from climate change inaction range from between 0.7% to 2.5% in 2060 as shown in Figure 23 below. These calculations are well within the estimates of other studies as described above. The losses are calculated for only for a number of related sectors such as agriculture and health. Other climate change impacts such as water stress or extreme weather events which are not included in this analysis would also have large economic impacts.

[11] Arent, D.J., R.S.J. Tol, E. Faust, J.P. Hella, S. Kumar, K.M. Strzepek, F.L. Tóth, and D. Yan, 2014: Key economic sectors and services – supplementary material. In: Climate Change 2014: Impacts, Adaptation, and Vulnerability.Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of theIntergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea,T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken,P.R. Mastrandrea, and L.L. White (eds.)]. Available from www.ipcc-wg2.gov/AR5 and www.ipcc.ch.

Assumptions of Climate Change Damage Estimations

In its scenario, the OECD assumes a 2.9% average global growth rate of GDP. Global greenhouse gas (GHG) emissions (excluding emissions from land use, land use change and forestry) are projected to rise from roughly 45 GT CO_2e in 2010 to just over 100 GT CO_2e in 2060. Concentrations of carbon in the atmosphere (CO_2 only) rise from 390 ppm to 590 ppm in the same time frame. In its central projection scenario, it calculates that a 2°C temperature increase is reached in 2055, and the associated global GDP annual loss amounts to 1.1%. Temperature increases to more than 2.5°C by 2060. The model calculates the economic impacts from sea-level rise, health, ecosystems, crop yields, tourism flows, energy demand and fisheries but does not include economic damages from extreme weather events or catastrophic risks.

Figure 23. Climate Change Impact on GDP



Source: Braconier et al, (2014)[12]

It is also important to note that the damages to GDP calculated above only refer to global GDP losses up to 2060, however GDP losses may reach 5% if greenhouse gas emissions continue rising after this period. Also the economic damages from climate change inaction do not take into account non-market impacts, tipping points and other catastrophic events (discussed in more detail at the end of the chapter). The damages and costs relate to an increase or reduction of greenhouse gas emissions from the energy-sector which represent approximately two thirds of current emissions. The damages and costs from greenhouse gas related to changes in land use and land cover and from other sectors are not included here. What is important is that emissions between now and 2060 (under an 'Inaction' scenario) would commit the world to a high-emissions infrastructure and the damages would continue for more than a century.

[12] Braconier H, Nicoletti G, Westmore B, (2014), 'Policy Challenges for the next 50 years', OECD Economic Policy Paper, July 2014, No. 9, Paris

Putting a Value on the Lost GDP

The use of discount rate plays a very important part in estimating future liabilities.

In the context of global GDP which is currently around $80 trillion and expected to more than triple by 2060, the sums of money potentially at stake are hard to comprehend, especially as they are annual and cumulative. Figure 24 shows the cost of liabilities or damages to global GDP from inaction to climate change which differ according to the discount rate that is being applied and the uncertainty level. The use of discount rate in climate change economics has been debated and there are very different views on what is the best discount rate to use (see 'The Discounting Debate' below).

Figure 24. The 3 Scenarios of the Potential Costs of Climate Change, Showing the Significant Effect that Different Discounting Rates Have

Discount Rate	NPV of 'Lost' GDP Low $ Trillion	Central $ Trillion	Upper $ Trillion
0%	-20	-44	-72
1%	-14	-31	-50
3%	-7	-16	-25
5%	-4	-8	-13
7%	-2	-5	-7

Source: Citi Research

The Discounting Debate

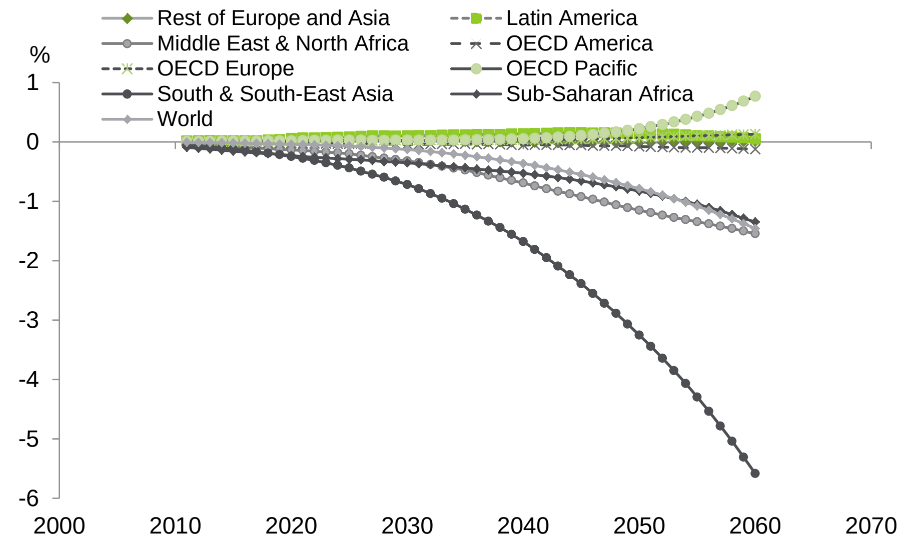
The rate at which future benefits and costs are discounted relative to current values often determines whether a project passes the benefit-cost test. This is especially true of projects with long term horizons, such as those to reduce greenhouse gas emissions. Whether the benefits of climate policies (which can last for centuries) outweigh the costs (many of which are borne today) is especially sensitive to the rate at which future benefits are discounted. Economists traditionally advocate that the discount rate should be primarily determined by the cost of capital; however others hold that it is unethical to discount the welfare of future generations and therefore a lower discount rate should be used to calculate the present value of future climate damages. Figure 24 shows the climate damages based on different discount rates − a low discount rate encourages early action primarily because future damages count for so much. Which is the correct discount rate to use is difficult to determine, and there is also a debate on whether the liabilities vs. cost of avoidance should be discounted at different rates, or whether we should a discount rate that reflects the actual market opportunities that societies face.

Economic Damages in Different Regions

South and South East Asia, Africa and the Middle East could experience the largest impacts on climate change

The extent of the economic damages from climate change is likely to differ substantially between different regions and different sectors. The highest impacts of GDP are foreseen in South and South East Asia, Africa and the Middle East, whereas countries in the upper Northern hemisphere such as Russia may be able to reap some economic benefits from climate change (Figure 25). One of the conclusions of the OECD studies described above was that climate impacts, to a large extent, are concentrated in vulnerable and high-populated regions. However it is important to look at the diagram below with some caution as economies do not operate in insolation, and the climate change impacts in one region could affect the economies in other regions. Impacts could also differ within one country or region. For example, even though the impact on the average national GDP would not be felt much in OECD Europe countries, it does not mean that these countries would not see any negative impacts. The relative gain in GDP for OECD Pacific countries occurs because the major economies in South and South East Asia would observe large losses in agriculture production. However extreme droughts are likely to happen in Australia which could negatively affect the OECD Pacific region's average GDP. Also some countries would be able to adapt more clearly to some of these impacts, by for example importing more food, however other regions would lose their competitive advantage in certain areas to other regions. Annual GDP is also an imperfect measure of the total economic costs of climate change as it does not include the wider-impacts on well-being.

Figure 25. Regional Economic (GDP) Impact of Climate Change to 2060 (Central Projection)



Source: Bracconier et al. (2014)

Co-Benefits from Reducing Emissions

There are also several co-benefits in reducing emissions including improving air quality standards, increasing energy security and reducing water use

There are also co-benefits from reducing greenhouse gas emissions which should be calculated when taking into consideration the liabilities and costs of avoiding of climate change. Reducing emissions can decrease fossil fuel imports for certain countries and therefore enhance energy security. Fossil fuel importers would spend less in our 'Action' scenario than in the 'Inaction' scenario (described in detail later). Reducing GHG emissions can also help improve air quality standards in many cities. In 2010, the cost of the health impact of air pollution (which is partly attributed to electricity generation and transport) in China and India was estimated at $1.4 trillion and $0.5 trillion respectively. Renewable resources such as solar and wind need little or no water resources when compared to fossil fuel power generation which needs water for cooling purposes. This could make a huge difference to water scarce countries that rely on freshwater for cooling in power generation.

Non-Market Impacts and Tipping Points, a Point of Caution

The loss to GDP maybe even higher if tipping points and non-market impacts are included in the analysis

Integrated assessment models used to estimate climate damages of inaction only measure those impacts that are quantifiable and largely concentrate on market or near market sectors such as agriculture, health etc.[13] However these studies omit other impacts which are difficult to measure such as tipping points, catastrophic risks and extreme weather events.[14] According to the IPCC 'no estimate is complete', however most experts believe that excluded impacts such as non-market effects are on balance all negative. These economic impacts are difficult to estimate and lie well outside the conventional market place, however they could have a substantial impact on a regional economy. For example, according to the World Bank, the economic damages and losses due to the floods in Thailand in 2011 was estimated at $46 billion, not to mention the enormous loss of life. It is not known with any certainty whether this event was triggered by climate change, but this shows the regional impacts an increase in catastrophic weather events could have on a region. Large tipping points on the other hand can occur when small climate changes trigger a large impact and can pose a systematic risk, such as the melting of the Greenland ice sheets. These risks increase with temperature rise and can induce shocks to both climate and the economic systems.

Is GDP the right measure to use?

There is also a discussion on whether annual GDP loss from climate change damage is the right metric to use. GDP measures only the flow of production, income and expenditure and does not include the stock of assets or wealth. As a result it does not record the deterioration in a country's natural resources which could ultimately be affected by climate change. Clearly including these risks would increase the potential financial costs from climate change (see Citi GPS: THE PUBLIC WEALTH OF NATIONS for more information).

[13] Nordhaus (2013)
[14] Delink et al. (2014)

Mitigation: The Costs of Action

Highlights

- Action to mitigate climate change inherently involves a cost. Hence we need to be either incentivized into taking a low carbon path, or penalized for not doing so. Action can take differing forms, most notably either legislation to force change, or via the creation of economic instruments such as putting a 'price' on carbon.

- If we compare the difference in cost between adopting a low carbon future and business as usual, we can derive a cost of mitigation. There are many differing methods of doing so, with some such as the IEA's long standing approach focusing purely on capital investment, while other approaches such as the one that we have adopted look at the total spend on energy thereby capturing fuel costs. Both approaches have their advantages and disadvantages, and we examine these, and highlight where our scenarios differ from those of the IEA.

- Over the next few chapters we examine the implications of Citi's 'Action' scenario which goes down a low carbon route, with a focus on the electricity sector as the largest current emitter and fastest growing area of energy usage globally. We examine the potential costs of transforming the energy mix in electricity production and its impact on emissions, and link this to an implied cost of carbon purely for the electricity sector, discussing how that might vary over time.

- What is perhaps most surprising is that looking at the potential total spend on energy over the next quarter century, on an undiscounted basis the cost of following a low carbon route at $190.2 trillion is actually cheaper than our 'Inaction' scenario at $192 trillion. This, as we examine in this chapter, is due to the rapidly falling costs of renewables, which combined with lower fuel usage from energy efficiency investments actually result in significantly lower long term fuel bill. Yes, we have to invest more in the early years, but we potentially save later, not to mention the liabilities of climate change that we potentially avoid.

- A low carbon route essentially involves investing more heavily in low emissions technologies such as renewables, investing less in fossil fuels, in particular coal in power and oil in transport, and investing significantly more in energy efficiency to reduce overall energy usage. We examine the implications of carbon for the integrated energy cost curves first derived in the original Energy Darwinism report, and in particular examine the implications of this potential mix-shift in terms of stranded assets.

- By comparing the cost of mitigation to the avoided 'liabilities' of climate change, we can derive a simple 'return on investment'. On a risk adjusted basis this implies a return of 1-4% at the low point in 2021, rising to between 3% and 10% by 2035. While not spectacular returns, against current low yields (and given the potential consequences), it represents a relatively attractive option.

- With a limited differential in the total bill of Action vs Inaction (in fact a saving on an undiscounted basis), potentially enormous liabilities avoided and the simple fact that cleaner air must be preferable to pollution, a very strong "Why would you not?" argument regarding action on climate change begins to form.

Different Types of Action

A simple reason why atmospheric concentrations of greenhouse gases has grown is that they have been put there as a result of our using historically the cheapest, easiest, or most readily available solutions to a requirement, such as energy. To look at it another way, adopting a lower carbon path is (at least superficially) more expensive, otherwise all things being equal we would logically have gone for a cleaner option.

Accordingly, to change our behavior entails a cost, and hence will require some form of mechanism to offset that cost, either involving incentives or penalties. There are two main ways to encourage a move to a low carbon economy:

1. **To enact legislation to force change**: an example of this is the new US legislation which aims to cut carbon emissions from power plants by 30% or the US Corporate Average Fuel Economy (CAFE) which encourages fuel efficiency improvements in the transport sector.

2. **To develop economic instruments**: that provide an incentive (or avoided penalty) to switch to low carbon technologies and fuel such as quotas, carbon pricing and tradable permits. Carbon pricing is one such economic instrument which will effectively put a price on GHG emissions both to provide an incentive to reduce them and also to minimize the costs of abatement by efficiently allocating capital to the most cost effective abatement options first. It also prices the externalities of GHG emissions encouraging a move to low carbon fuels if carbon is adequately priced.

The next two chapters examine both of those mechanisms, in the form of deriving a cost of carbon for the power sector, and an examination of the effects of legislation relating to energy efficiency, mainly in the transportation market.

Assessing the Incremental Cost of Action

There are many different approaches to estimating the cost of action to mitigate climate change, each with their own benefits and pitfalls. There are equally as many global integrated energy models which are used by the investment community, corporates and governments, which highlight differing energy mixes going forwards.

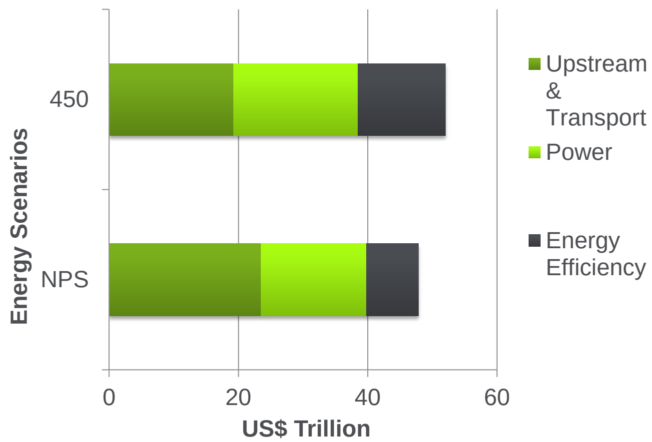
Of the numerous global energy investment scenarios available, perhaps the most comprehensive is that put forward by the IEA. We examine this scenario, before moving on to discuss the benefits and limitations of this approach, and to highlight where our own 'Action' and 'Inaction' scenarios differ in their approach and findings.

The IEA Scenarios and Where We Differ

$53 trillion capex investment is needed to invest to have a chance of limiting temperature increase

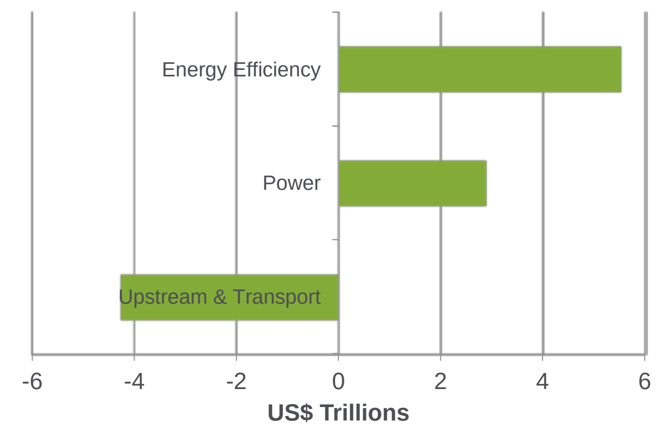
The IEA bases its analysis on capital investment using its own integrated global climate and emissions model which it has been publishing and refining for more than 20 years; accordingly it is worthy of significant respect. The IEA estimates that the total capex investment required for energy (and efficiency) from 2014 to 2035 is $48 trillion in its central energy scenario (the so-called 'New Policies Scenario' or NPS scenario), increasing to $53 trillion for a 50% chance of meeting a 2°C temperature increase target (the '450 scenario'), as shown in Figure 26. The '450 scenario' is so called as it lays out a scenario which would limit greenhouse gas concentrations to 450ppm, the level generally accepted that would give the world a 50% chance of limiting climate change to 2°C or less. The IEA's 'New Policies Scenario' lays out an energy mix where current and signaled emission reduction commitments are enacted, and replaced on expiry; this is effectively the IEA's base case. The 'Current Policies Scenario' assumes that as current policies expire, they are not replaced or extended.

Figure 26. Cumulative Investment Required Under the IEA's NPS and 450 Scenarios



Source: IEA (2014a), Citi Research

Figure 27. Delta in Investment by Energy Segment between the IEA's 450 and NPS Scenarios

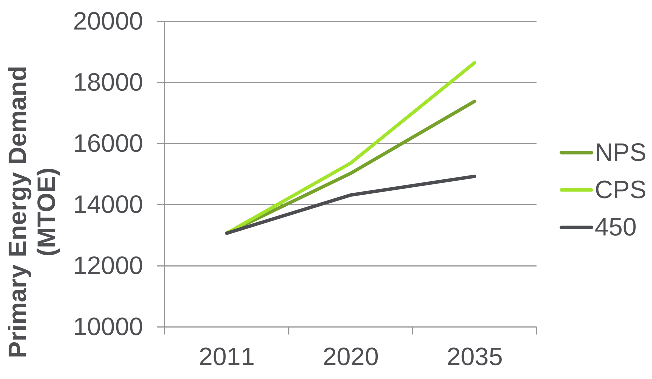


Source: IEA (2014a), Citi Research

As Figure 26 and Figure 27 demonstrate, the energy sector's transition in the IEA's '450 scenario' requires not only more capital investment but a notably different allocation of capital. Investment in power generation and energy efficiency in the '450 scenario' increases by $2.9 trillion and $5.5 trillion respectively, whilst investment in upstream, transport and refining of fossil fuels decreases by $4.2 trillion when compared to the NPS scenario. Much of the incremental investment in power generation is allocated to the deployment of renewables, whilst over $3 trillion of the incremental investment in energy efficiency is allocated to the transport sector.

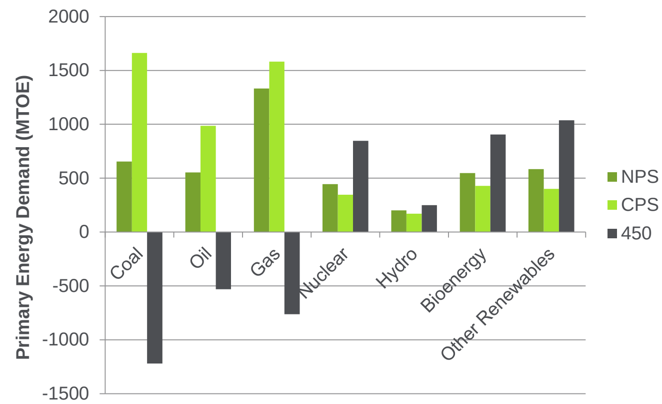
In terms of fuel mix, Figure 28 and Figure 29 below present the primary energy demand and changes therein from 2011 in 2035 under the IEA's three scenarios.

Figure 28. Primary Energy Demand Under Three Scenarios



Source: IEA (2013)

Figure 29. Change in Primary Energy Demand from 2011 (in 2035)



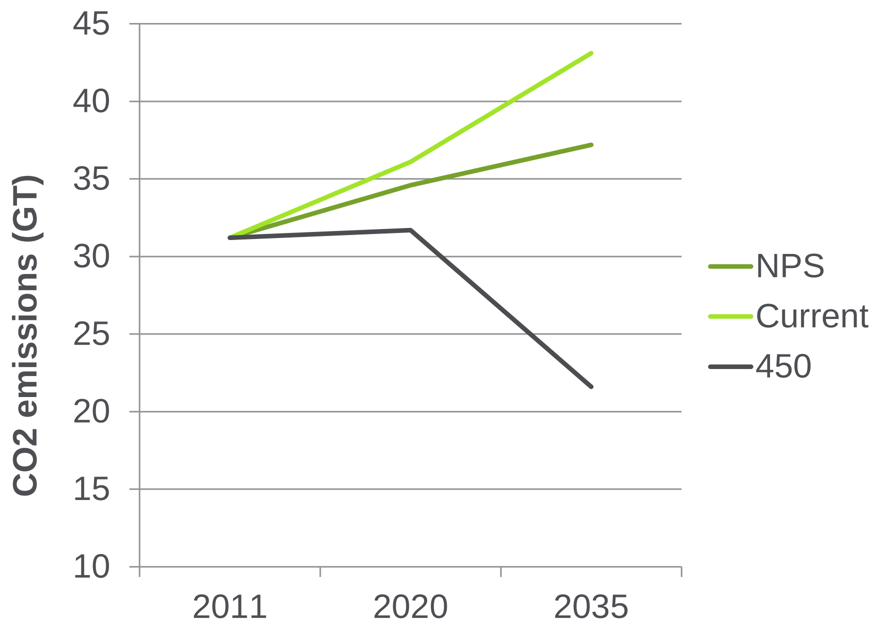
Source: IEA (2013), Citi Research

As one can see from the diagram above, the '450 scenario' reduces the primary demand for fossil fuels and increases the demand for nuclear, bioenergy and other renewables.

Impact on Emissions

In meeting the '450 scenario', energy-related emissions would need to peak by 2020 and decline to around 22GT in 2035 as shown in Figure 30 below. The cumulative emission gap between the NPS and the '450 scenario' is around 156GT of CO_2. The largest reduction in emissions occurs in power generation followed by the transport and industry sectors (IEA, 2014).

Figure 30. CO_2 Emissions in Different Energy Scenarios



Source: Citi Research

Deriving a Return on Investment

One of the advantages of examining purely capex alongside the potential damages of climate change, is that one can derive a 'return' on that investment in terms of avoided costs in a way that a holistic energy spend approach cannot.

Figure 32 shows the NPV of the energy capex spend of going down a low carbon route with a 50% chance of limiting temperature increase to 2°C (the IEA's '450 scenario') and the energy capex spend for a scenario which increases temperature by over 3°C (the NPS scenario).

Figure 31. The 3 Scenarios of Potential Cost of Climate Change in Terms of NPV Lost to GDP, at Different Discount Rates

	NPV of 'Lost' GDP		
Discount Rate	Low $ Trillion	Central $ Trillion	Upper $ Trillion
0%	-20	-44	-72
1%	-14	-31	-50
3%	-7	-16	-25
5%	-4	-8	-13
7%	-2	-5	-7

Source: Citi Research

Figure 32. NPV of the Differential Cost Between the IEA's NPS (Business as Usual) and 450 (Low Carbon) Scenarios, Using Different Discount Rates

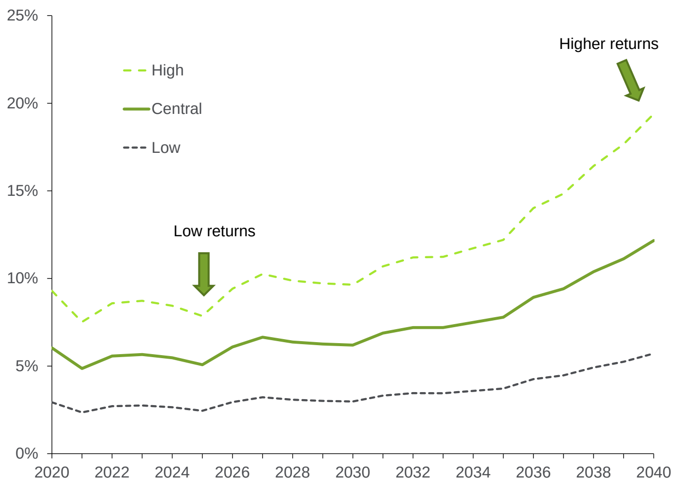
Discount Rate	NPS $ trillion	450 $ trillion	Difference $ trillion
0%	48	53	4.8
1%	44	48	4.2
3%	36	40	3.4
5%	31	34	2.7
7%	27	29	2.3

Source: Citi Research, IEA

Figure 31 and Figure 32 demonstrate that at low 'societal' discount rates, climate change damage costs outweigh the incremental cost of adopting a low carbon path. It is notable that it is only with relative high discounting rates on the damages that the cost would seem hard to justify. Given the inter-generational debate we see some merit in using a much lower 'social' discount rate than might be applied to usual investment decisions. Conversely, when comparing the potential costs and benefits of Action, it would seem disingenuous to not discount the liabilities (in terms of potentially avoided costs), but to then compare this to a discounted cost of Action.

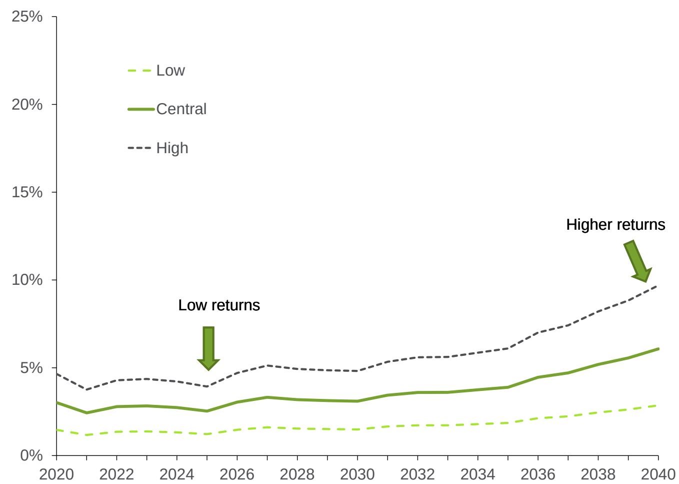
In this section we compare the incremental cost of following a low carbon path with the estimated value of reduced damages in the future. It is also useful to look at these investment choices in terms of returns as one would any normal investment choice. Figure 33 and Figure 34 show the implied return in terms of avoided liabilities of inaction, with reference to the incremental undiscounted cost of Action ($4.8 trillion). The numerator used in the calculation is the incremental 'saved' GDP in each year, thereby giving an implied annual 'return' on that incremental investment figure. Figure 34 then takes these implied returns and halves them; this would seem appropriate given that the IEA's '450 scenario' is derived to offer a 50% chance of avoiding a temperature increase of more than 2°C, i.e. the return is effectively risk adjusted.

Figure 33. Implied Return of Incremental Avoided Costs on Annual Spend



Source: Citi Research

Figure 34. Risk-Adjusted Return of Incremental Avoided Costs on Annual Spend, to Reflect 50% Chance of Avoiding Climate Change



Source: Citi Research

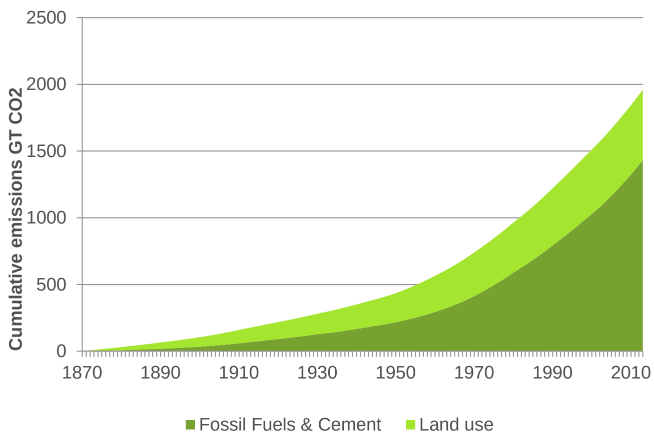
As avoided losses increase, the returns increase to between 3-8%

As the figures show, while the risk adjusted returns are limited at lows of 1-4% depending on the scenario, as the avoided losses increase, those returns increase dramatically to between 3-10%. While still not enormous, in the context of current yields, and certainly in the context of the potential implications of inaction (and that later remedies are significantly more expensive), the low carbon route begins to look relatively compelling. Given that there is a reasonable (though not spectacular) return, and on the basis that simplistically cleaner air must be preferable to pollution, the "Why would you not?" argument again comes to the fore — an argument which becomes progressively harder to ignore over time. Coupled with the fact the total spend is similar under both action and inaction, yet the potential liabilities of inaction are enormous, it is hard to argue against a path of action. Admittedly some industries will suffer, others will benefit, and the effects will be felt differently around the world; the challenge therefore is to get policymakers to think holistically and to act accordingly, and to allow the funds to flow in the right directions (as examined in the final chapter of this report, "Making it Happen").

Investment in Power Generation

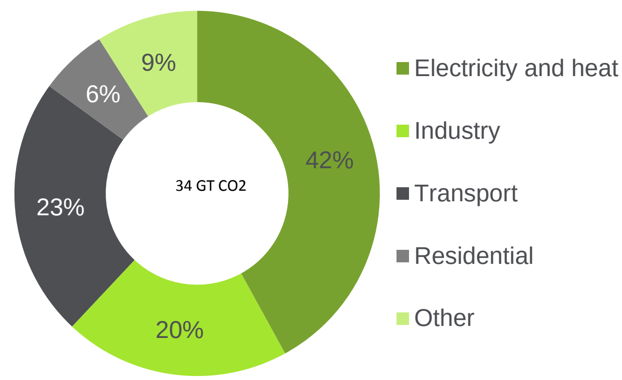
Out of all greenhouse gas emissions (measured in CO_2 equivalents for comparative purposes) energy-related CO_2e emissions made up the majority of greenhouse gas emissions estimated at 65% in 2010. Of those emissions, 90% were from the combustion of fossil fuels.

Figure 35. Cumulative CO_2 Emissions from Energy and Land Use



Source: Boden et al. (2013), Houghton et al. (2012), Citi Research

Figure 36. Percentage of Annual Energy-Related Emissions by Sector (2010)



Source: IEA (2014), Citi Research

Of those energy related emissions, by far the largest part (42% in 2013) were from the power sector, itself the largest single greenhouse gas emitter in the climate change debate. Transport was responsible for a further 23%, meaning that combined with power, they accounted for two thirds of emissions from energy, which itself was two thirds of total emissions.

We focus on the electricity sector in detail as it is the largest emitter

While we recognize that the electricity market is only part of the puzzle to combat climate change, given that it is the largest single greenhouse gas emitter in the climate change debate, policy action in the power market would make potentially the most meaningful impact to greenhouse gas emissions, if designed and implemented appropriately. Hence we have focused our attention in this report on the costs associated with transforming the electricity market, what impact these transformations have on the 'carbon budget' and the dynamics of this transformation.

We have constructed two energy scenarios which form the basis of the analysis in this report:

- **Citi's 'Inaction' scenario**: An energy mix out to 2040 which is essentially a business as usual scenario, which assumes the current energy mix remains relatively constant and that there is no investment in energy efficiency. While there obviously *is* current investment into energy efficiency we are trying to assess the incremental amount which is being spent on following a low carbon future to examine the 'affordability' of preventing climate change, and hence a 'zero' baseline is necessary.

- **Citi's 'Action' scenario**: In constructing this scenario to 2040 we have focused the bulk of our analysis on the power sector, as the largest single emitter in the energy segment, (an approach which is outlined in more detail in the next chapter). We assume significantly greater levels of renewable deployment than the IEA's '450 scenario' and that costs reduce faster. Moreover, our approach to assessing costs differs materially. Efficiency, largely in transport, is also examined in a separate chapter. In our assumptions for the transport and industry segments of energy we have adapted the IEA's assumptions, applying assumptions of our own and altering time frames. Having focused on the power sector in this report, both of these areas we intend to be subject of more detailed follow-on reports.

Levelized Cost of Electricity: A Different Measure of Cost

Given the existing rigor of the IEA's capex-based approach, we have chosen to adopt a slightly different approach to assessing the overall likely costs of energy to the global economy.

We take into consideration not only capex spending but also include the overall avoided fuel costs of moving to a low carbon future.

Instead of estimating the capital cost requirements to enable a transition in the global energy market (which has already been done) we focus our Citi analysis on the overall costs of energy procurement. In the power sector where we focus our analysis, we therefore use a levelized cost of electricity (LCOE) approach which captures both the fuel and capital costs over the useful life of an asset. Effectively the LCOE answers the question: "At what price does a certain power plant have to sell electricity to break even for a plant operator?"

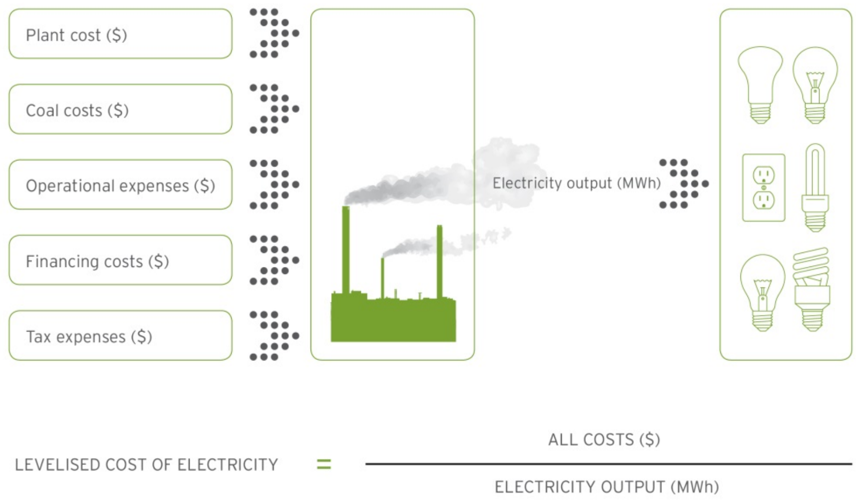
Examining just capex spend in the energy transformation runs the risk of missing the avoided cost in terms of future reduced fuel demand. While this is arguably partially captured by lower required upstream capex in fossil fuels, we believe that adopting an LCOE approach to the electricity sector therefore provides a more holistic view. No approach is perfect however; an LCOE approach has its own drawbacks in terms of assumptions on commodity prices, regional differentials etc., but we believe it can complement capex-based analysis if used in conjunction, and more it allows different types of analysis such as comparing the total amounts 'spent' on energy to be compared to for example GDP levels. The benefits and pitfalls of both approaches are examined later.

Why is LCOE Useful to Compare Different Technologies?

Different technologies have different cost profiles. While renewable energy costs more to build relative to a unit of energy produced, this ignores the fact that once built, renewables plants incur limited costs compared to fossil fuels, as they consume no fuel. The useful life of a coal-fired plant is about 40 years whilst for a solar photovoltaic (solar PV) plant it is 25 years. This makes the usefulness a dollar of capex spent on a coal-fired plant difficult to compare to a dollar spent on a solar PV plant.

As the levelized cost of electricity captures all costs of electricity generation over the lifetime for each technology it is widely used to compare cost competitiveness of different fuel types.

Figure 37. Levelized Cost of Electricity



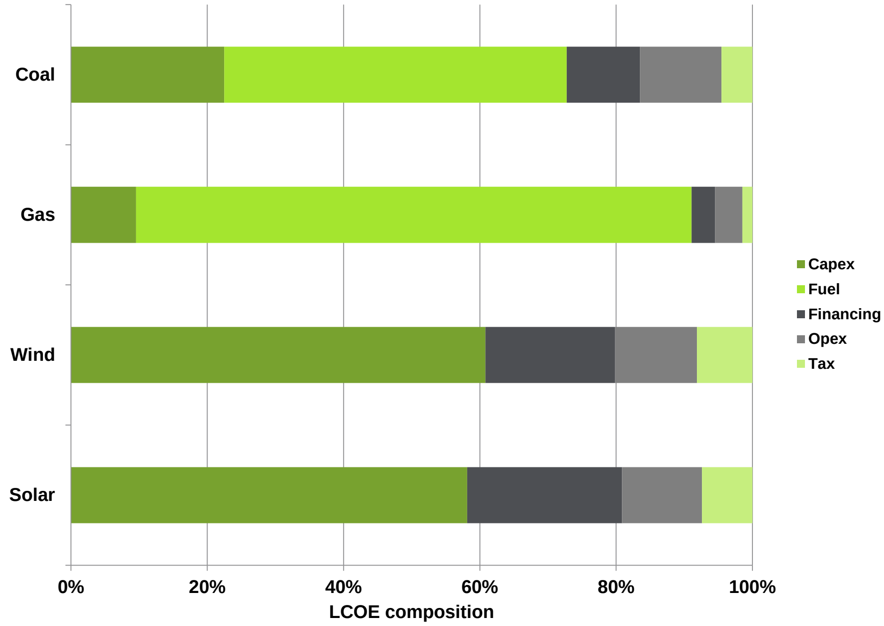
Source: Citi Research

The Benefits of an LCOE Approach (1): The Difference in Cost Breakdown

Capex makes up the majority of the costs for renewables, whilst for gas 80% of the costs relate to fuel

The cost composition between different technologies can vary quite markedly. For renewable energy, upfront capital expenditure on equipment makes up the majority of costs: around 60%. As renewable energy projects are generally levered with debt, financing costs also play an important part in the cost equation. On the other hand, coal and gas-fired plants are more sensitive to fuel costs. This is particularly extreme for a gas-fired plant, for which fuel costs make up over 80% of its levelized cost of generation. Variations in gas price can therefore cause large swings in the competitiveness of gas-fired plants. For coal-fired plants the economics are less biased towards fuel cost while on the other hand upfront construction costs make up 25% of total cost of electricity produced. Figure 38 shows a full cost breakdown of all technologies considered.

Figure 38. Levelized Cost of Electricity Breakdown for Different Generating Types



Source: Citi Research

As Figure 38 highlights, capex as a proportion of the overall cost of a unit of electricity generated by different technologies varies dramatically, from around 10% for a combined cycle gas turbine (CCGT), up to around 60% for both wind and solar; conversely, fuel makes up over 80% of gas LCOE, versus zero for wind and solar.

Accordingly, examining capex on a standalone basis runs the risk of overstating the cost of renewables, and understating the total cost of conventional generation technologies. This is particularly true if any form of discounting is used, as the bulk of the costs for renewables are upfront, whereas for gas they would be backloaded.

The Benefits of an LCOE Approach (2): The Pace of Change

Given the rapid increase in the pace of substitution in energy markets over the last two years, the main focus of the original Citi GPS: ENERGY DARWINISM report was to show how dangerous assumptions on capex can be when the pace of change in an industry is so rapid, and the rate of evolution so fast.

One of the key theories from the original energy Darwin report was highlighting these differing rates of cost evolution of different generation technologies. Solar in particular was exhibiting learning rates in excess of 20% (i.e. the cost of a panel would fall by >20% for every doubling of installed capacity), wind at 7.4%, gas was evolving via the shale revolution in the US, while nuclear was becoming more expensive, and liquefied natural gas (LNG) had also increased in cost by around 10% per annum over the last decade.

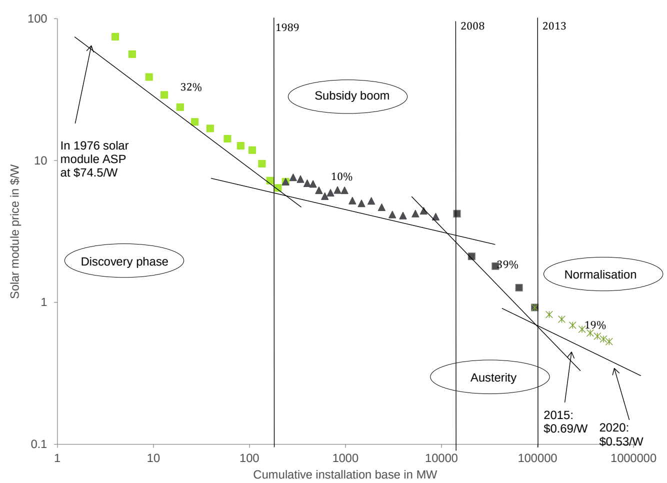
Hence the report highlighted the lack of certainty over returns on many investments at the upper end of the cost curves in the energy industry over the next five years, let alone their total lives, which could be anywhere up to 40 years. This effect has become even more prevalent even more quickly than we anticipated, with significant quantities of stranded assets across the whole breadth of energy industry, from coal mines, gas fields, to power generation facilities. Accordingly, understanding those rates of change and the risk of stranded assets (and whether assets will actually be built, thereby affecting capex spend, given the lack of certainty over returns) becomes ever more important. As before, we are not trying to say that LCOE is 'better' than a capex based approach, rather each has its own advantages, and an LCOE approach highlights certain aspects that could be missed in a capex only approach; examining LCOE in conjunction with capex-based approaches should therefore add to the debate.

Renewable Energy's 'Technology' Characteristics

Learning rates for renewables should continue making the technologies ever more competitive, and ultimately cheaper than conventional, as is the case in many markets already

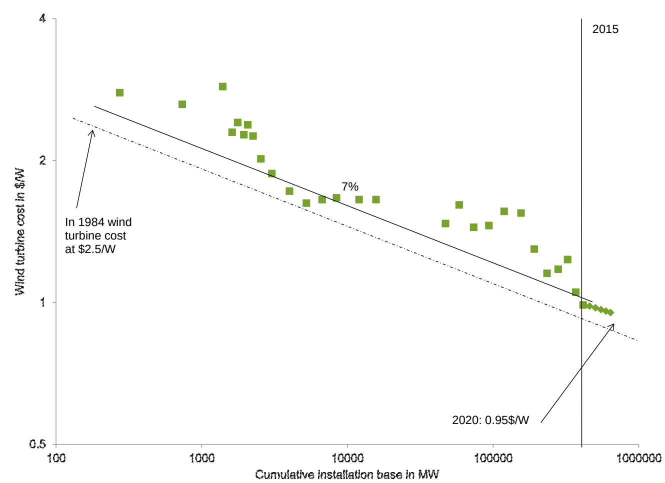
We expect installation costs for wind turbines and solar modules to continue to decline rapidly. Admittedly past declines in the solar PV space will be more difficult to replicate as there were many one-offs such as the manufacturing move to China and margin compression across the value chain. We estimate that going forward learning rates in solar PV modules will be up to 19% whilst onshore wind turbine learning rates are likely to hover around 7%. We find it useful to convert these learning rates (which express cost reductions for every doubling of installed capacity), into year on year reductions. For solar PV modules the year on year reduction would amount to 2% whilst for onshore wind this number is 1%.

Figure 39. Solar Learning Rate 19%



Source: BNEF, Citi Research

Figure 40. Wind Learning Rate 6.7%



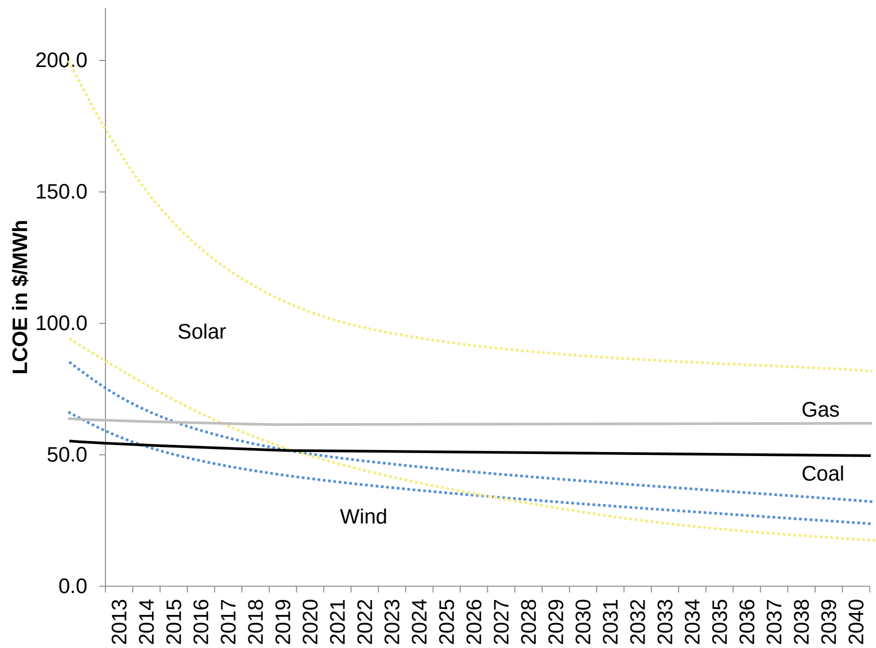
Source: BNEF, Citi Research

Why Renewable Energy Could be a Viable Solution

Renewable energy will become much more competitive in the future

In the initial years, the cost of procurement from carbon-light sources such as renewable energy is costly (solar at ~$90-180/MWh, wind at $60-80/MWh, versus coal at $60-70/MWh and gas at $50-100/MWh). Solar PV in particular is more expensive than conventional fuels in most parts of the world (with exceptions in regions with abundant sunshine such as Latin America and the Middle East). However, as component costs and financing of renewable projects decline, renewable energy becomes more competitive – for onshore wind, parity is reached earlier than for solar PV. Beyond that point there is a financial advantage in installing renewable energy and we should think of installing renewable energy as a benefit rather than a cost to society. Figure 41 shows our estimates of the global cost of power by various fuel-types.

Figure 41. Cost of Energy from Renewables Expected to Fall Drastically Over the Next Years



Source: Citi Research

This is one of the key benefits of examining total spend on an LCOE basis, as it demonstrates well the shifting relative economics of different generation technologies. Most important is this point that as renewables become 'cheaper' than conventional, there is effectively a net saving to using them.

The Disadvantages of an LCOE Approach

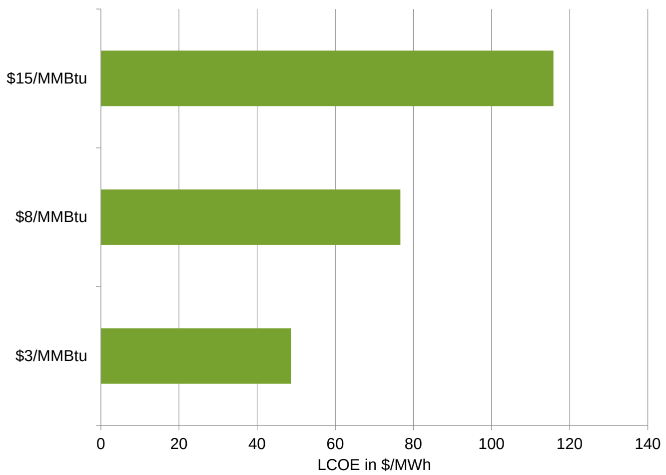
The disadvantages to using LCOE, or conversely the advantages of using a purely capex-focused approach are as follows:

- The main argument against the use of LCOE and total costs is that it requires significant assumptions on commodity prices, which are of course extremely difficult to forecast with any accuracy particularly over a 25 year time horizon. However, one could counter that those prices will have an equally large impact on the returns that the upstream capex will generate – by assuming that fuel costs are adequately captured by upstream capex therefore assumes that an adequate return will be earned on that investment, and therefore it could be argued makes just as large indirect assumptions on future commodity prices as an LCOE approach does. This highlights once again the work contained in the original Energy Darwinism report, that the pace of change in energy markets makes returns on investment highly uncertain for many forms of energy assets, particularly conventional.

- It can be argued that a purely capex-based approach *does* incorporate fuel costs, in that they are effectively captured in the upstream investment into coal mines, oil and gas fields etc., the fuel 'costs' essentially providing a return on the capital investment. However, once again this assumes that load factors, fuel costs and selling prices will be adequate, and hence once again assumes in many ways just as many assumptions as an LCOE approach does.

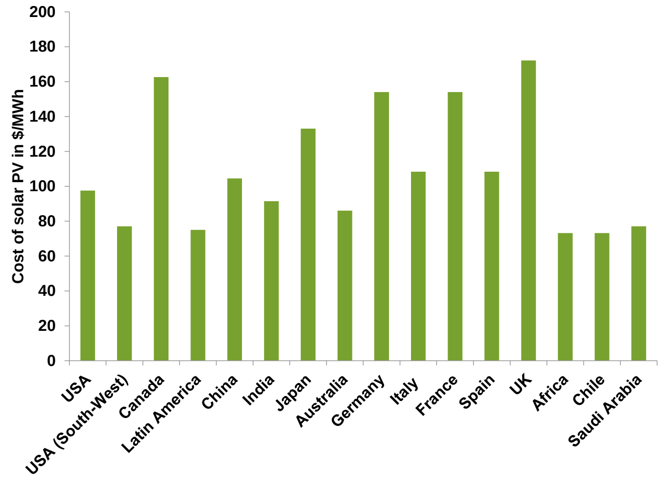
- The costs of both conventional and renewable energy vary significantly by region. The economics of gas-fired plant are most sensitive to gas prices, in which there is a large discrepancy between regions as shown in Figure 42. In the US the shale gas boom has drastically driven down gas prices and the oil price drop has now brought gas prices down to below $3/MMBtu. However, in other regions, gas prices are still higher due the lack of availability, such as Europe where gas trades at $7-8/MMBtu, and in Japan with gas prices up to $15/MMBtu. These price discrepancies across regions have a large impact on the economic viability of gas-fired plants vs renewables. The economics of renewable energy also vary significantly around the world. In particular the cost of solar PV electricity is very sensitive to insolation levels (sunshine hours), which varies drastically across regions as highlighted in Figure 43.

Figure 42. Gas Economics Heavily Depend on Gas Price



Source: Citi Research

Figure 43. Solar PV Cost of Electricity Generation Across Different Regions – Citi Projections for 2015



Source: Citi Research

Capex vs. LCOE Conclusions

So, both a purely capex-based approach and an LCOE approach have benefits and limitations. By choosing to use an LCOE approach we are not saying it is better – merely different, and it does highlight some of the benefits of following a low carbon path. In reality of course neither approach is perfect, and while there are arguments that there are 'less' assumptions in adopting a capex-based approach, this has been done very effectively by institutions such as the IEA, and to replicate it here might add limited additional value to the debate. What adopting an LCOE and holistic approach alongside the capex-based work does emphasize is the rapidly reducing costs of alternative energy, and in particular the ultimate savings via lower spend on commodities used in a lower carbon path.

Figure 44. The Advantages and Disadvantages of a Capex-Based Approach and LCOE

Advantages of capex/ disadvantages of LCOE	Advantages of LCOE/disadvantages of capex
Less apparent assumptions on fuel costs vs. LCOE	Total costs of generation vary widely by technology between upfront capex and fuel cost
Less regional variation in costs vs. LCOE	Does not penalize up front cost nature of renewables if discounting is used
Avoids transportation cost assumptions	Highlights effects of fuel savings via renewables
Intermittency of renewables and associated grid costs is not captured in LCOE (unless associated T&D etc. spend is adjusted)	Highlights relative speeds of changes in costs of differing generation technologies

Source: Citi Research

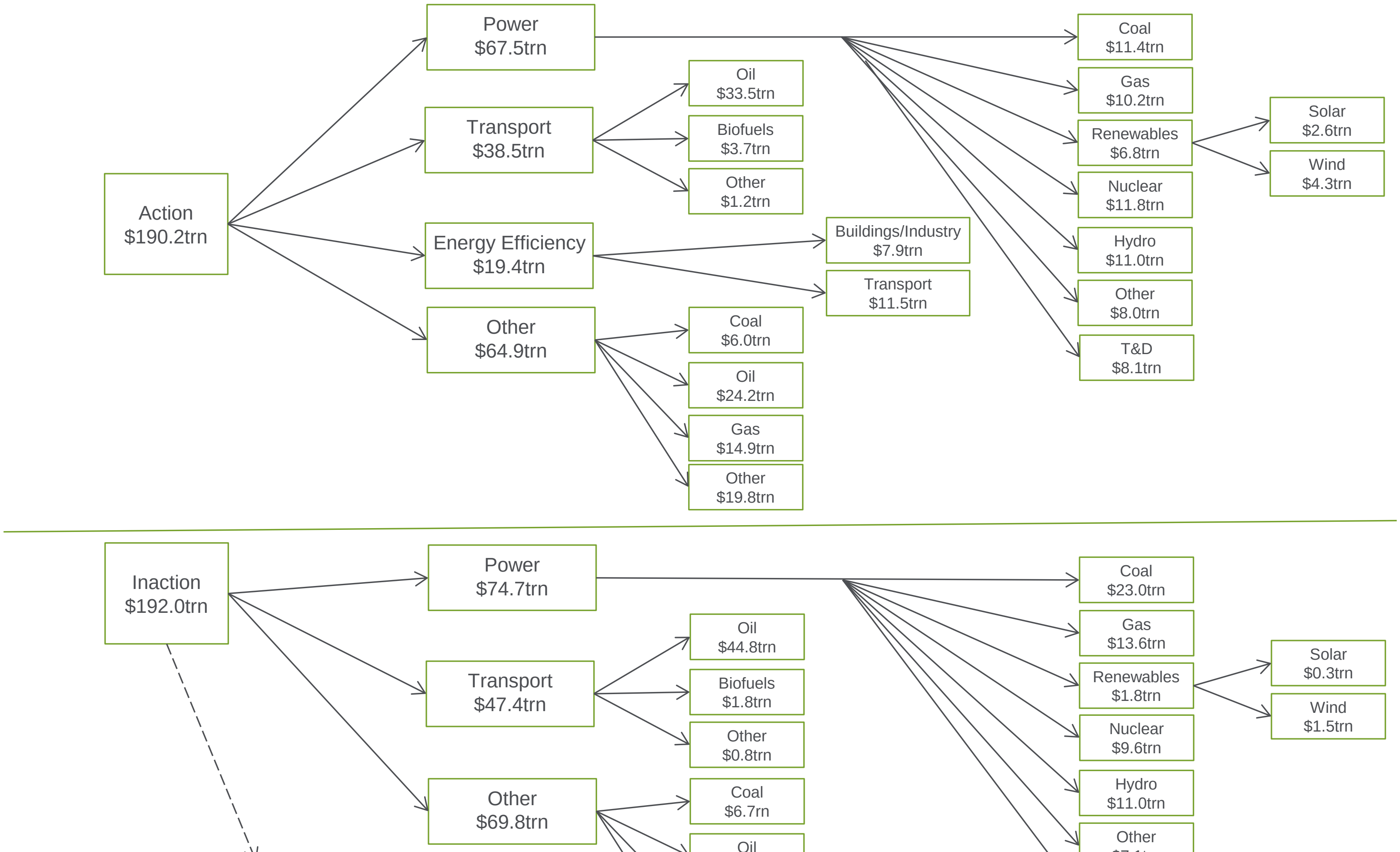
Assessing the Global Spend on Energy Over the Next Quarter Century

As discussed, while other methods assess the investment required in energy to follow a low carbon path, we have adopted a slightly different approach, looking at the potential total energy spend under differing energy mix assumptions. The holistic approach provides an additional perspective that can be used alongside a purely capex-focused approach, allowing us to examine its significance in different ways such as allowing us to assess the total amount spent on energy supply in a year relative to the size of the global economy, as well as gaining a perspective into the quantity of stranded assets potentially ‘created’ by following a low carbon path.

Applying the LCOE assumptions to our adapted global power model produces the total spend scenarios outlined in Figure 45. To be clear, this chart shows not just the capital investment required in power, but incorporates the cost of fuel used. For other areas of use it incorporates energy usage at current Citi commodity forecast prices and then held flat from 2018 onwards to 2040. In terms of assumptions we have not made any assumptions on long term commodity prices beyond 2018, but simply assumed that these prices remain flat over the life of the analysis. Clearly changes in commodity prices (discussed in a later section) would have a material impact on relative costs and savings, though we would note that the low nature of some commodities such as oil reduces investment therein, as well as potential savings from not using that fuel (i.e. following a low carbon path).

The detailed analysis of the costs of the impact of climate change, and increased investment in both the power market and energy efficiency is provided in dedicated chapters later in this report. However, at this stage we provide a summary of those holistic costs of capex and fuel spend to the global economy over the next quarter century, as shown in Figure 45.

Figure 45. Estimated Spend on Energy Globally, 2015-40 Under Citi's 'Action' and 'Inaction' Scenarios, vs. Potential 'Costs' of Climate Change

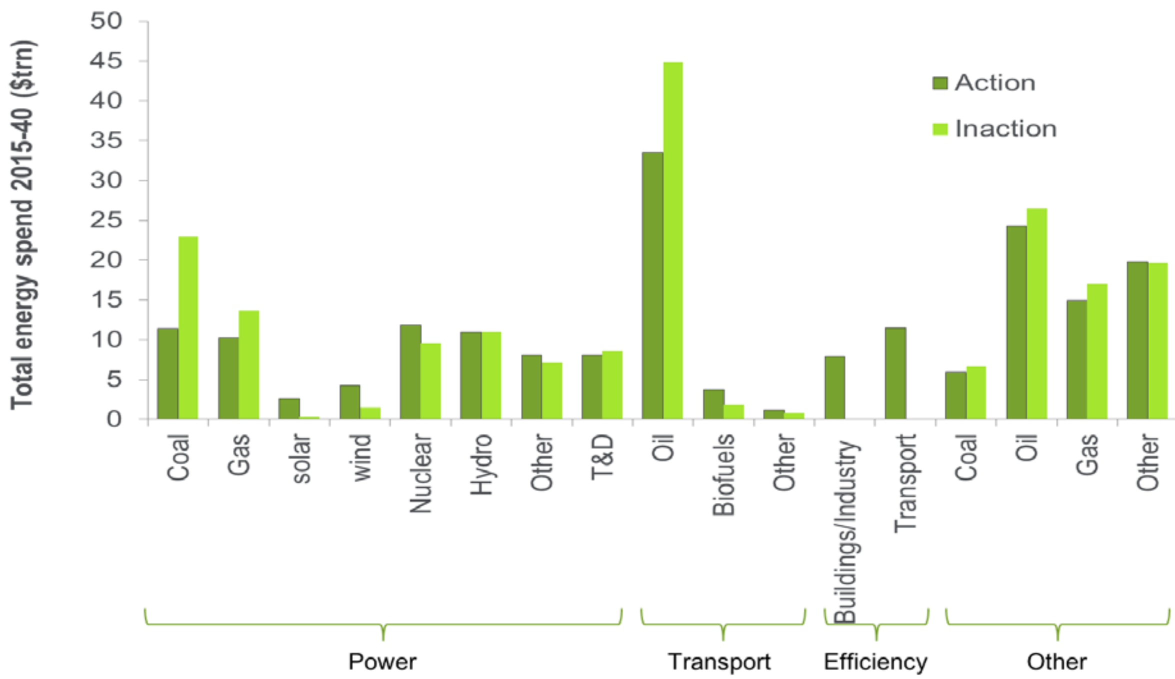


Discount Rate	NPV of damages by scenario ($trn) Low	Medium	High
0%	20.5	44.3	72.0
1%	14.4	31.0	50.3
3%	7.3	15.7	25.4
5%	3.9	8.3	13.4
7%	2.2	4.7	7.4

Note: Pricing assumptions from 2018 onwards for illustration purpose only: Coal at $74/mt, Gas at $6.95/mmbtu and Oil at $80.80/bbl

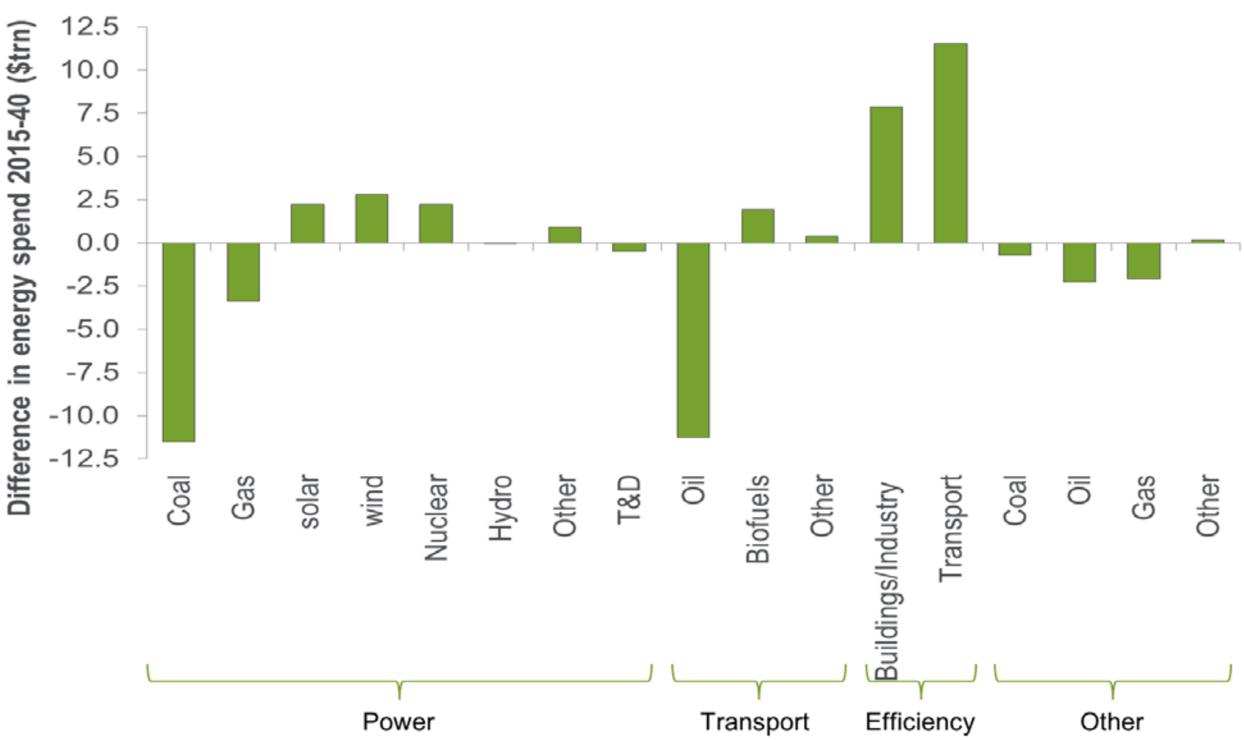
Source: Citi Research

Figure 46. Changes in Total Energy Spend Between our 'Action' and 'Inaction' Scenarios.



Source: Citi Research

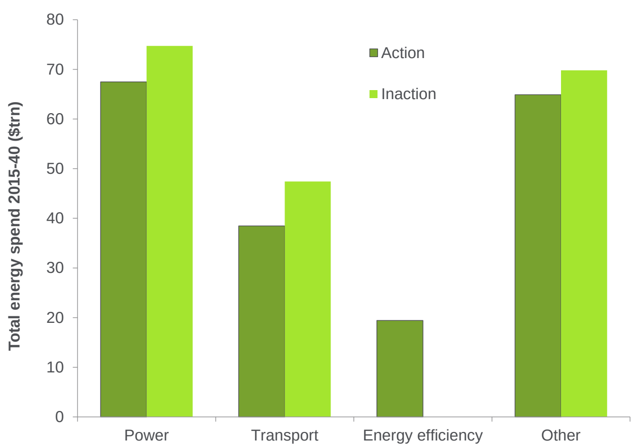
Figure 47. Difference in Total Investment Between our 'Action' and 'Inaction' Scenarios, 2015-2040.



Source: Citi Research

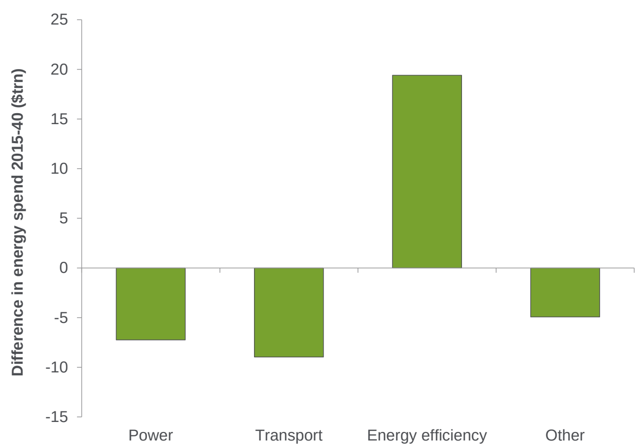
Figure 45 shows the total spend and split therein of energy spending over the next 25 years under both our 'Action' and 'Inaction' scenarios. While electricity (the main focus of this report examined in more detail in a later section) is calculated on an LCOE basis, other areas such as transport are calculated using the expected volumes used, multiplied by current forecast prices, with prices held constant beyond 2018 (i.e. no assumptions are made regarding changes to prices). Clearly this latter point is important – if commodity prices such as oil had not plummeted in recent months, the total spend figures would be considerably higher.

Figure 48. Energy Spend in 'Action' and 'Inaction' Scenarios by Segment, 2015-40



Source: Citi Research

Figure 49. Change in Energy Spend in 'Action' and 'Inaction' Scenarios by Segment, 2015-40



Source: Citi Research

The difference in spending between the 'Inaction' and 'Action' scenario is marginal

While not perfect, this approach is designed to capture how much we will 'spend' on energy over the next quarter century. The key point to take is that the difference in total spend is marginal between the two scenarios, mainly because although we spend significantly more on renewables and energy efficiency in the 'Action' scenario, this is offset by reduced spend on fossil fuels (as renewables don't use 'fuel', and energy efficiency is effectively negative fuel use). However, if we go down the route of 'Inaction' and do not invest into a low carbon economy, we could potentially face some negative impacts such as changes to rainfall patterns, a reduction in crop production, an increase in sea level rise etc., the estimated costs of which are highlighted in the box on Figure 45. Whilst these could ultimately affect the livelihoods of many people, they will also have a negative effect on global GDP. This is addressed in more detail in other chapters.

This approach also makes it easier to compare the costs of energy to global GDP in terms of energy acting as a brake or accelerator for global growth in a way that analyzing purely capex perhaps doesn't. It also gives a sense of the value of the assets which remain 'unused', i.e. becoming stranded under a low carbon scenario. Admittedly this approach would vary dramatically depending on pricing assumptions, but as we discussed in a later chapter, it highlights the decreasing proportion of total energy costs which are in fact fuel.

Drivers of Change (1): The Power Market Transformation

Highlights

- The power market is the single largest carbon emitter in the energy market and currently emits 12.6GT CO_2e in 2015. This number is projected to double by 2040 in the absence of investments into abatement measures such as renewable energy (mainly solar PV and onshore wind) and energy efficiency to reduce electricity consumption.
- Coal is the single largest carbon emitter in the power market and makes up 41% of the fuel mix given its low cost, yet emits we estimate 73% of the total emissions from power generation.
- In this chapter we examine in detail our Citi 'Action' and 'Inaction' scenarios with a particular focus on the power sector as the largest single emitter. In particular we focus on where our scenarios differ from others such as those from the IEA; in summary we assume faster cost reductions and a greater penetration of renewables. While most examinations of cost focus purely on upfront capex, we have chosen to adopt a different approach, namely 'LCOE', which captures both the upfront investment costs and operating costs (including fuel) thereafter.
- In summary we find that the incremental cost of following a low carbon route in the power sector (our so-called Citi 'Action' scenario) is only around $1.1 trillion out to 2040. While costs are more expensive in early years, as renewable technologies become cheaper in later years due to their impressive learning rates, we effectively save money via the lower fuel usage in conventional plants, as well as reduced overall consumption via investment in energy efficiency.
- As a result, carbon emissions in the order of 200GT CO_2e can be avoided between 2015 and 2040. A third of the avoided carbon can be attributed to energy efficiency investments and the other two thirds can be attributed to renewable energy investments.
- We examine the implications of these incremental costs for a potential price of carbon, how it might vary around the world, and then incorporate a cost of carbon into the original 'Energy Darwinism' integrated global energy cost curves to examine the implications for stranded assets. Unsurprisingly, coal is the biggest loser, while the key beneficiaries are renewables given their limited lifetime emissions.
- We also highlight the potential that energy storage offers, in terms of offsetting the intermittency of renewables, as well as its wide reaching implications for energy markets overall.

Citi's Trajectory into a Carbon-Light Electricity Mix

In order to make a cost and impact assessment, we look at the Citi 'Action' and 'Inaction' scenarios and assess the investment requirements and the impact on carbon emissions under both scenarios:

Citi 'Action' scenario: This scenario reflects a transition to a carbon-light electricity mix and investments in (1) renewable energy and (2) energy efficiency to mitigate CO_2 emissions. In this scenario we assume an electricity generation CAGR of 1.6% between 2015 and 2040 – a lower rate than our 'Inaction' scenario due to energy efficiency investments. Further our Citi 'Action' scenario assumes renewable energy penetration increases to 34% by 2040 from 6% in 2012.

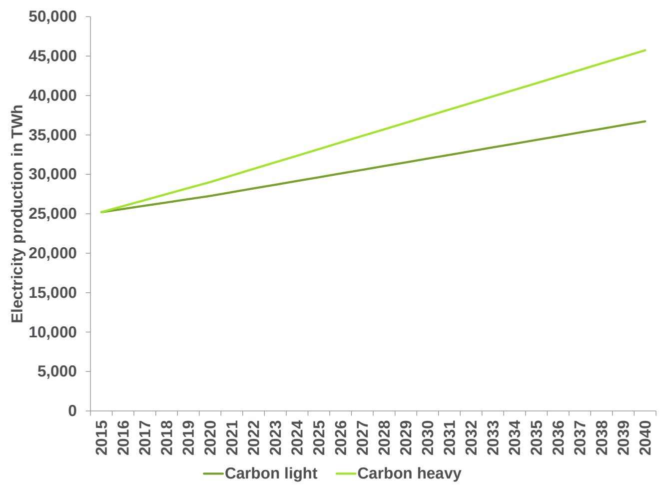
Citi 'Inaction' scenario: This scenario reflects no change in our current carbon-heavy electricity mix. In this scenario renewables investment will pick up but will only stay at 6% penetration by 2040. Fossil fuels will make up two thirds of our electricity mix with coal continuing to take the largest market share with 40%. Further this scenario assumes a higher electricity generation CAGR of 2.4% between 2015 and 2040 due to zero investments into energy efficiency.

Power consumption will grow at a lower rate in our 'action' scenario; fossil fuels would decline from 65% to 28% of the power market

In our 'Action' scenario where investments are triggered, we estimate power consumption to grow at a slower rate than in our inaction scenario due to investments into energy efficiency. In 2040 we estimate this gap to widen to 20% between both of our scenarios (Figure 50).

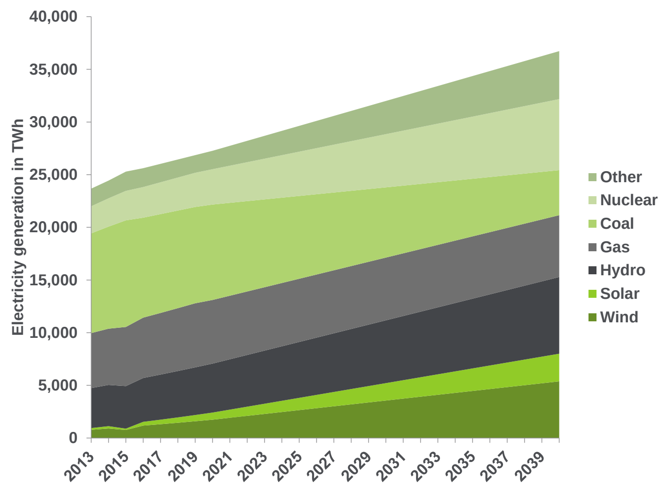
For the electricity mix we have assumed that in our status quo scenario the electricity mix stays constant over time weighted towards fossil fuels – coal 40%, gas 22% and renewables 6%. In our Citi 'Action' scenario we have assumed that the fossil fuel share declines from currently over 64% to 28% whilst solar PV and onshore wind energy could make up to 22% of the electricity mix in our Citi 'Action' scenario (Figure 51).

Figure 50. Annual Electricity Production for Both Citi Scenarios



Source: Citi Research

Figure 51. Carbon-Light Scenario Sees Fossil Fuel Share to Decline from 64% in 2015 to 28% in 2040



Source: Citi Research

Where Are We Different From the IEA?

Solar PV would increase at 53GW per annum from 2013-2020

The key difference between our forecasts and the IEA's is the assumed penetration of renewable energy in the electricity mix. In our Citi 'Action' scenario we have assumed a higher rate of penetration for solar PV and onshore wind installations (Figure 53 and Figure 54). In particular, our forecasts for solar PV deviate significantly from the IEA's.

Figure 52. Fuel Mix for Electricity Generation by 2020

2020	Citi Action	Citi Inaction	IEA 450	IEA CPS
Fossil	58.3%	67.4%	60.3%	64.1%
Renewables	12.4%	5.8%	10.3%	9.0%
Nuclear	12.3%	10.7%	12.3%	11.3%
Hydro	17.0%	16.0%	17.0%	15.6%
Total	100%	100%	100%	100%

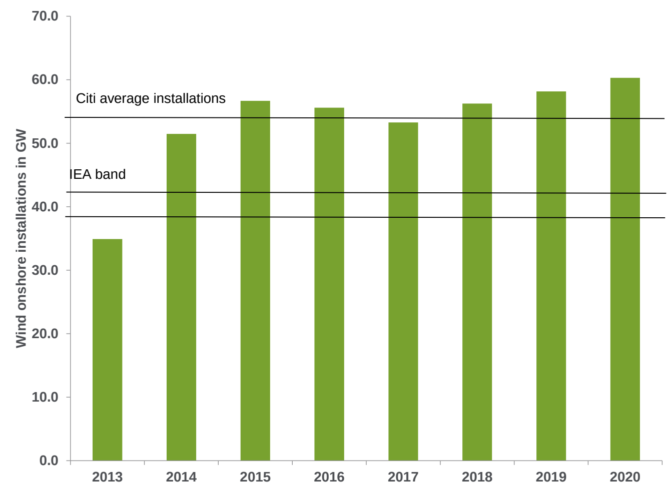
Source: Citi Research

Our granular country by country solar PV forecasts show an average installation rate of 53GW per annum 2013-2020. This compares to 33-34GW installations by the IEA (lower bound New Policy scenario, upper bound 450 scenario), as seen in Figure 53. These differentials are also clear in our wind assumptions (Figure 54).

Figure 53. Citi Solar PV Installations

Source: IEA (2014), Citi Research

Figure 54. Citi Onshore Wind Installations



Source: IEA (2014) Citi Research

Our bottom-up assumptions for both wind and solar by country are shown in Figure 55 and Figure 56.

Figure 55. Citi Solar PV Forecasts

Annual Demand (MW)	2007A	2008A	2009A	2010A	2011A	2012A	2013A	2014A	2015E	2016E	2017E	2018E	2019E	2020E
Europe	2,362	4,835	6,763	12,014	21,478	15,236	10,572	6,985	7,836	7,066	8,240	8,762	9,204	9,669
Italy	70	338	719	2,321	9,446	3,564	1,364	395	533	720	756	794	833	875
Germany	1,400	1,600	4,500	7,392	7,485	7,600	3,304	1,901	1616	1777	1866	1960	2058	2160
Spain	600	2,500	100	275	372	275	143	22	25	29	33	38	44	51
France	50	100	100	707	1,671	1,022	649	926	1019	1120	1233	1294	1359	1427
UK	0	0	0	115	784	725	1,082	2,273	2955	1477	2216	2327	2443	2565
ROE	242	297	1,344	1,204	1,720	2,050	4,030	1,468	1688	1941	2136	2349	2467	2590
North America	200	350	400	1,129	1,961	3,568	5,056	6,908	9,177	12,212	6,840	7,182	7,542	7,919
USA	200	350	350	984	1,712	3,300	4,621	6,312	8,521	11,504	6,097	6,402	6,722	7,058
Canada	0	0	50	145	249	268	435	596	656	708	743	781	820	861
South America	3	3	7	5	11	95	103	614	1,297	1,752	2,103	2,314	2,545	2,799
Chile	0	0	0	0	0	2	13	483	773	966	531	584	643	707
Rest of Latam	3	3	7	5	11	93	90	131	524	786	1572	1729	1902	2092
Asia	390	630	840	1,953	5,272	8,832	22,117	25,357	29,067	30,635	30,678	32,524	34,119	35,564
Japan	300	300	500	900	1,155	2,000	7,092	10,253	9,000	8,000	6,000	6,060	6,121	6,182
China	40	30	200	450	3,240	5,000	12,920	13,000	16,000	17,600	18,480	19,404	20,374	21,393
Korea	50	300	100	148	157	252	361	480	490	499	509	520	530	541
India	0	0	20	95	300	980	968	815	2,000	2,800	3,780	4,536	4,990	5,239
Other Asia	0	0	20	360	420	600	776	809	1,578	1,735	1,909	2,004	2,104	2,210
Asia Pac	20	20	100	387	774	1115	861	921	939	958	977	997	1017	1037
Australia	20	20	100	387	774	1,115	861	921	939	958	977	997	1017	1037
South Africa	0	0	0	0	2	7	177	901	1,126	1,408	1,760	2,112	2,534	3,041
ROW	100	100	150	1,942	2,606	2,200	1,392	3,315	4,973	6,216	10,567	11,095	11,650	12,232
Total	3,075	5,938	8,260	17,430	32,104	31,053	40,278	45,001	54,415	60,246	61,165	64,985	68,610	72,261

Source: Citi Research

Figure 56. Citi Onshore Wind Forecasts

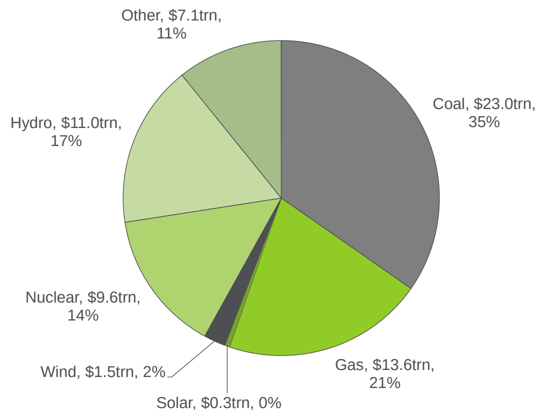
Annual installations (MW)	2007 A	2008 A	2009 A	2010 A	2011 A	2012 A	2013 A	2014 A	2015 F	2016 F	2017 F	2018 F	2019 F	2020 F
Asia	5,226	8,391	15,451	21,468	20,963	15,645	18,212	26,006	31,414	29,215	30,297	31,919	32,425	33,000
China	3,304	6,110	13,785	18,928	17,631	12,960	16,088	23,196	28,000	25,000	25,000	26,000	26,000	26,000
India	1,575	1,810	1,271	2,139	3,019	2,337	1,729	2,315	2,778	3,334	3,667	4,034	4,235	4,447
Japan	229	342	205	249	202	78	47	130	260	494	1,235	1,482	1,778	2,134
Rest of Asia	118	129	190	152	111	270	348	365	376	387	395	403	411	419
Europe	8,662	8,601	10,730	10,176	10,396	12,774	11,660	12,857	10,184	10,516	11,050	11,581	12,120	12,737
Germany	1,667	1,656	1,874	1,414	1,880	2,199	2,980	5,279	2,500	2,500	2,500	2,500	2,500	2,500
Spain	3,522	1,544	2,471	1,463	1,051	1,110	175	28	50	50	50	50	50	50
Denmark	3	38	302	284	207	206	610	105	100	100	100	100	100	100
Italy	603	1,010	1,113	948	1,081	1,240	434	108	111	115	116	117	118	119
France	888	950	1,170	1,396	837	816	631	1,042	1,250	1,438	1,582	1,740	1,827	1,918
UK	427	568	1,271	1,003	1,308	2,093	1,882	1,736	1,500	1,620	1,750	1,890	2,041	2,204
Portugal	434	712	673	171	673	150	195	184	190	195	197	199	201	203
Netherlands	210	478	- 10	54	3	119	302	141	145	150	151	153	154	156
Sweden	217	260	512	603	736	847	724	1,050	890	600	550	490	460	450
Poland	123	268	181	455	436	880	894	444	488	537	591	650	715	787
Turkey	-	311	343	528	477	506	647	804	965	1,158	1,389	1,598	1,837	2,113
Rest of Europe	568	806	830	1,857	1,707	2,608	2,186	1,936	1,994	2,054	2,074	2,095	2,116	2,137
North America	5,630	8,767	11,083	6,218	7,938	14,985	3,063	7,359	9,851	10,392	6,559	7,087	7,629	8,220
US	5,244	8,244	10,018	5,212	6,631	13,078	1,084	4,854	7,000	8,000	4,000	4,400	4,840	5,324
Canada	386	523	950	689	1,257	939	1,599	1,871	2,058	1,441	1,513	1,588	1,636	1,685
Mexico	-	-	115	317	50	968	380	634	793	951	1,046	1,098	1,153	1,211
Latam	30	121	538	372	804	1,249	1,234	3,750	3,691	3,889	4,102	4,330	4,575	4,838
Brazil	10	94	265	321	504	1,077	953	2,472	2,596	2,725	2,862	3,005	3,155	3,313
Chile	18	-	148	4	-	33	130	506	300	345	397	456	525	603
Rest of Latam	2	27	125	47	300	139	151	772	795	819	844	869	895	922
Pacific Region	158	485	578	295	345	358	655	567	600	600	200	200	200	200
Australia	7	482	406	278	236	358	655	567	600	600	200	200	200	200
Rest	151	3	172	17	109	-	-	-	-	-	-	-	-	-
Africa and Middle East	160	98	230	199	5	95	90	934	926	988	1,055	1,130	1,212	1,302
Ethopia	-	-	-	-	-	81	90	-	-	-	-	-	-	-
Egypt	80	55	65	120	-	-	-	-	-	-	-	-	-	-
Morocco	60	10	119	33	5	-	-	300	300	300	300	300	300	300
South Africa	-	-	-	-	-	-	-	560	616	678	745	820	902	992
Rest	20	33	46	46	-	14	-	74	10	10	10	10	10	10
Total	19,866	26,463	38,610	38,728	40,451	45,106	34,914	51,473	56,665	55,600	53,263	56,246	58,160	60,298

Source: Citi Research

$1.1 Trillion: The Cost of Overhauling the Power Market

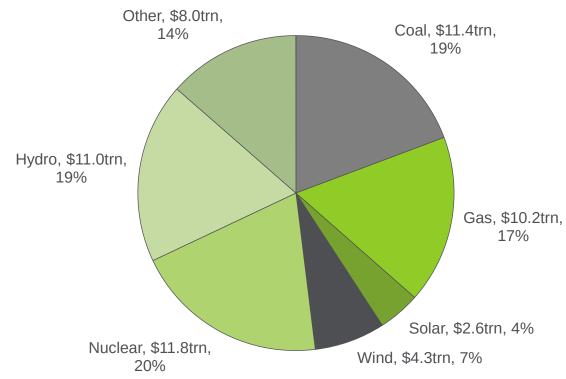
Figure 57 and Figure 58 show the split of total investment in the power market under the two different Citi scenarios. As the charts show, the difference in the total bill between 2015 and 2040 is $6.9 trillion, with 'Action' being less costly, though of course this ignores the increased investment in energy efficiency which more than offsets this saving.

Figure 57. Total Spend on Electricity Using an LCOE Approach in Citi's 'Inaction' Scenario. (Total spend = $66.1trn)



Source: Citi Research

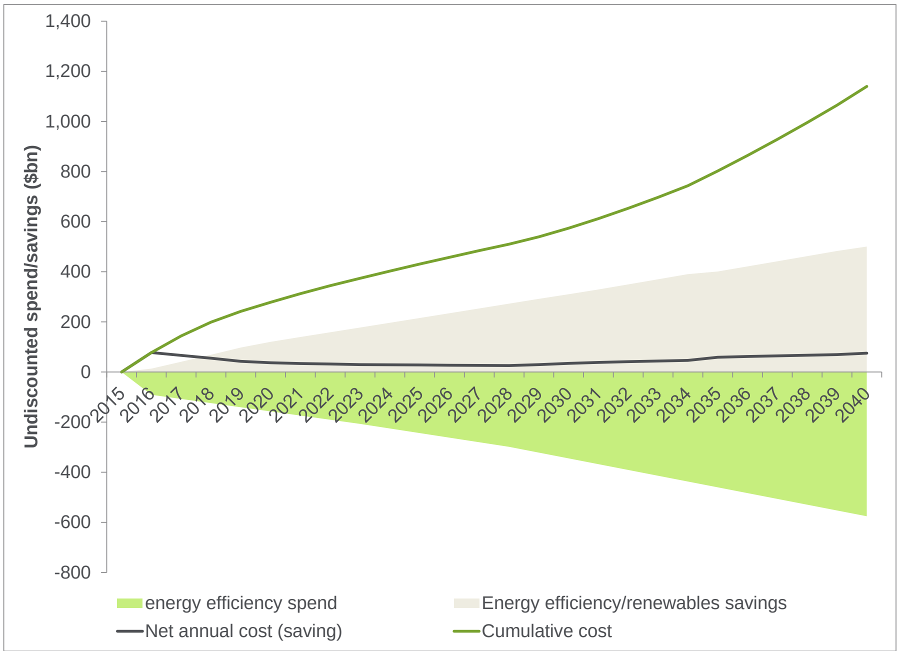
Figure 58. Total Spend on Electricity Using an LCOE Approach in Citi's 'Action' Scenario. (Total spend = $59.4trn)



Source: Citi Research

Converting these differentials to a timeline showing incremental investment vs. savings on power costs produces the results shown in Figure 59.

Figure 59. The Net and Cumulative Incremental Costs of Following the Citi 'Action' Scenario



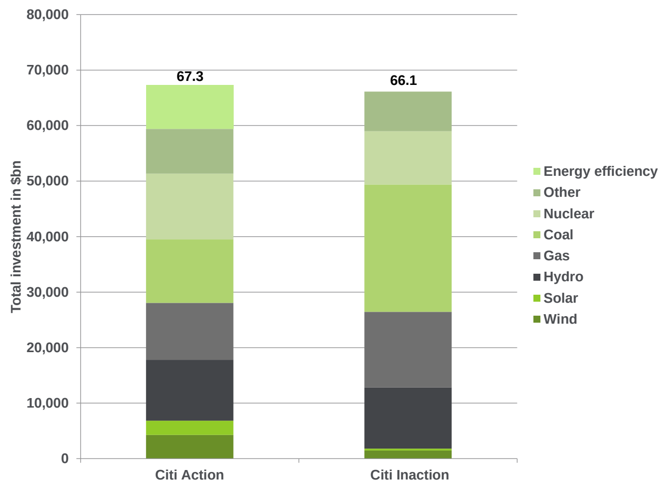
Source: IEA (2014), Citi Research

We estimate that by 2030 the cost of power production from renewables will have come down far enough to be fully cost competitive. However, this benefit is then offset by investments needed for energy efficiency on both the demand-side and the industry-related side.

Cumulative incremental electricity investment between both scenarios would amount to $1.1 trillion

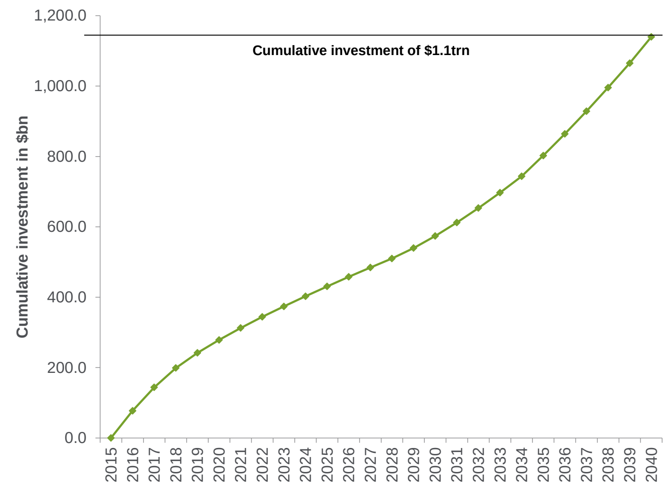
Overall, in the period 2015-2040 we estimate that cumulative incremental investments will amount to $1.1 trillion, as highlighted in Figure 59, Figure 60, and Figure 61.

Figure 60. Total Investment in Both Citi Scenarios 2015-40 (Including Efficiency, but Excluding T&D Spend)



Source: Citi Research

Figure 61. Incremental Difference in Investments Annually Between Both Scenarios



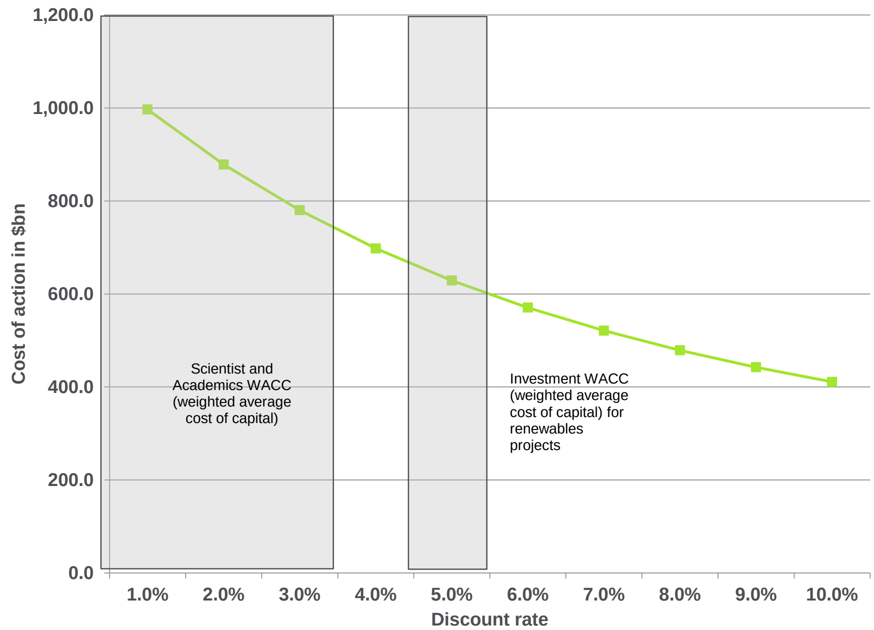
Source: Citi Research

However, this amount could be a smaller sum if one discounts those costs that arise in the future. The question then becomes what is the right discount rate to use when considering investments into a carbon-light power market. From an investment point of view one would consider the cost of capital of renewable projects. Ultimately project owners and bank providers bear the financial risk when investing into these infrastructure projects. Further, the equity on projects bears the majority of financial risk for those projects. Currently the cost of equity for renewables projects is around 5-7% depending on what type of asset and how stable and trustworthy the regulatory regime is deemed. However as our investment costs are denominated in real terms, the corresponding cost of equity could drop by 1-2% to bring the real project cost of equity to around 4-5%.

However, contrary to the argument that investments into a carbon-light future should be discounted from a financial viewpoint, climate change scientists have argued that discounting should reflect an inter-generational trade off, as discussed earlier. Fundamentally, the idea of discounting is being used in finance because monetary value can be enhanced from one period to another via say a bank savings account, and therefore a higher monetary value is assigned to the present. When considering climate change, some scientists argue that society should not use any form of discounting as it implicitly assigns a higher value to present generations vs. future generations.

The difference between a low discount rate and a discount rate that reflects the equity risk of renewable projects can bring down costs from $1.1 trillion to $0.4 trillion in net present value (NPV) terms. However we also note that a consistent discounting rate needs to be used when contrasting investments with avoided liabilities.

Figure 62. Cost of Action: How Much Does It Cost Society To Transform Our Current Electricity Market in Net Present Value (NPV) Terms



Source: Citi Research

Impact of Power Transformation on CO_2

For a 50% chance of meeting temperature increase of 2°C, cumulative GHG emissions need to be capped at 2,000GT CO_2e

In this section we examine our scenarios in emissions terms. Malte Meinshausen has predicted for an illustrative 50% chance to not exceed long term temperature rises beyond 2 degrees Celsius; the allowable greenhouse gas emissions budget is 2,000GT CO_2e between 2000 and 2049.

Meinshausen, who makes a distinction between greenhouse gases (Kyoto gases below) and carbon dioxide (CO_2), has attached the following probabilities to exceeding 2 degree Celsius in long term temperature rises for different greenhouse gases and carbon dioxide emission levels in Figure 63.

Figure 63. Meinshausen Greenhouse Gas Budget

		Probability of exceeding 2 degrees Celcius	
Indicator	**Emissions**	**Range**	**Illustrative default case**
Cumulative total CO2 emissions 2000-49	886Gt CO2	8-37%	20%
	1,000Gt CO2	10-42%	25%
	1,158Gt CO2	16-51%	33%
	1,437Gt CO2	29-70%	50%
Cumulative Kyoto-gas emissions 2000-49	1,356Gt CO2e	8-37%	20%
	1,500Gt CO2e	10-43%	26%
	1,678Gt CO2e	16-51%	33%
	2,000Gt CO2e	29-70%	50%

Source: Meinshausen et al (2009)

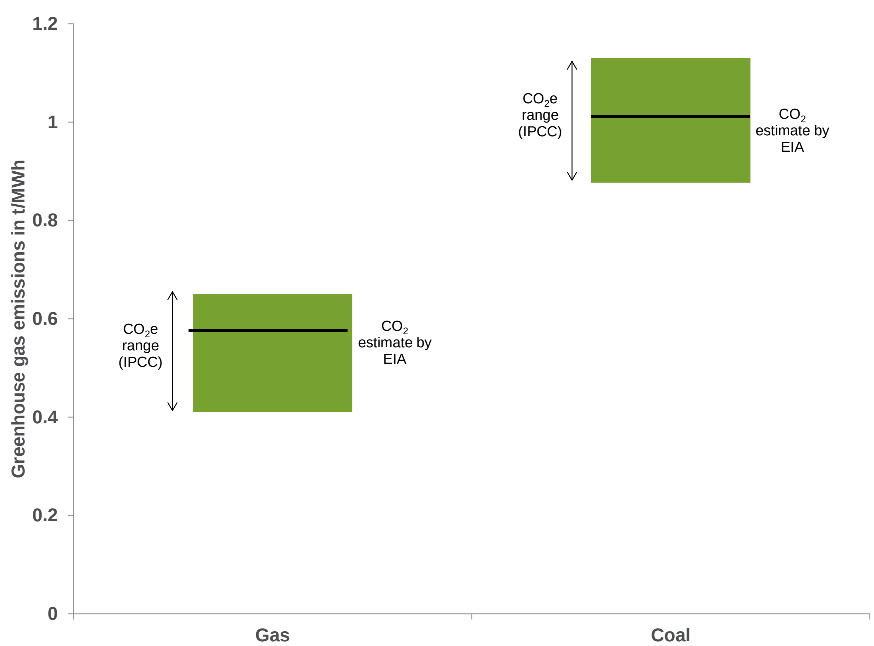
Difference between CO_2 and CO_2 Equivalent

One important distinction in the emissions debate is the difference between CO_2 emissions and CO_2 equivalent (CO_2e) emissions. CO_2e emissions measure greenhouse gases – this captures both CO_2 emissions plus other gases such as methane, F-gases and N_2O adjusted for their global warming potential relative to CO_2.

For the power market however, greenhouse gas emissions in CO_2e and CO_2 emissions are to a large extent aligned. The vast majority of emissions when generating electricity from fossil fuels are in the form of carbon dioxide, therefore there is little deviation between both CO_2 and CO_2e emissions in the power market. However, this depends on what is being measured. The IPCC (Figure 64) calculates the lifecycle GHG emissions (from cradle to source) of power generation. This includes not only the CO_2 emissions from the combustion of fossil fuels in power plants, but also methane and other greenhouse gas emissions from the extraction of fossil fuels, extraction of materials used for solar and wind power generation and transportation. The EIA data calculates only the CO_2 emissions from power generation and does not include other greenhouse gas emissions.

In the context of linking temperature rises to emissions, quoting the budget in CO_2e terms is a more accurate measure as it captures other important greenhouse gases on top of carbon dioxide which are responsible for global warming. Similarly the IEA quotes their 450 scenario in greenhouse gas terms, where the 450ppm refers to greenhouse gas concentration (CO_2e). Therefore, for this study we use CO_2e (IPCC figures) and compare those to the greenhouse gas budget described by Meinshausen which includes all cumulative Kyoto-Gas emissions.

Figure 64. Greenhouse Gas vs. Carbon Dioxide Emissions per Unit of Electricity Generation

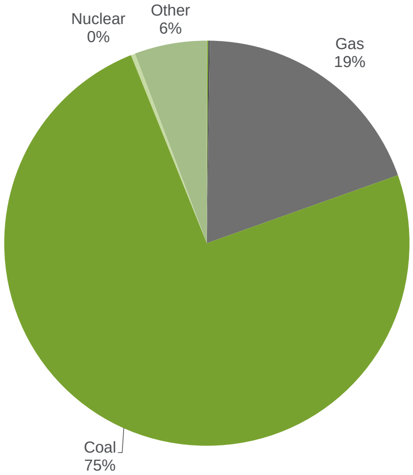


Source: IPCC (2014) and EIA

In 2015, coal and gas fired generation will emit 9.2 and 2.6 GT CO_2e respectively

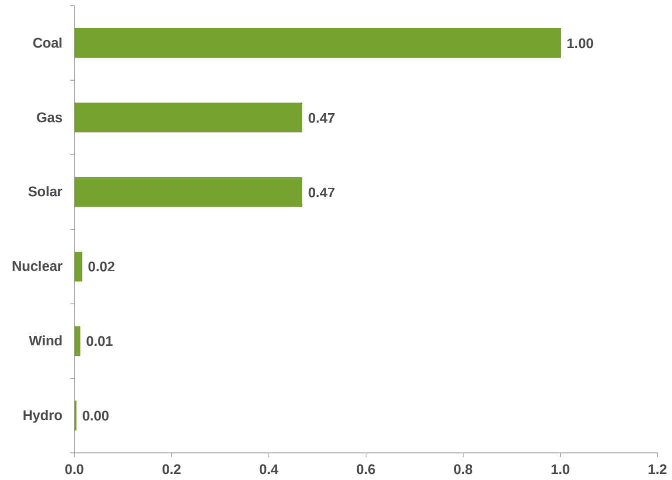
Currently, coal- and gas-fired electricity generation are the largest greenhouse gas emitters (CO_2e) in the power market (Figure 65), estimated at 9.2GT CO_2e and 2.6GT CO_2e, respectively. Future investments into energy efficiency will help reduce electricity consumption as a whole whilst substitution from coal-fired to gas-fired to renewable energy generation will reduce emission intensity. Both measures should lead to reduced greenhouse gas emissions of 9.3GT CO_2e by 2040, a 60% reduction compared to a business as usual scenario.

Figure 65. Total Greenhouse Gas Emissions in 2015 in Power Market – Citi Estimates



Note: 'Other' is mainly emissions from electricity generated from oil
Source: Citi Research

Figure 66. Greenhouse Gas Lifecycle Emissions in t CO_2e per MWh



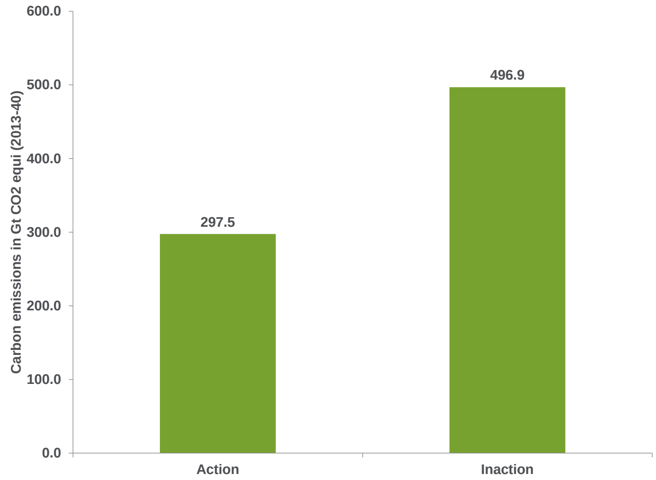
Source: Citi Research

There is a difference of over 200GT of CO_2e of cumulative emissions emitted between our action and inaction scenario

Implications of Citi Scenarios

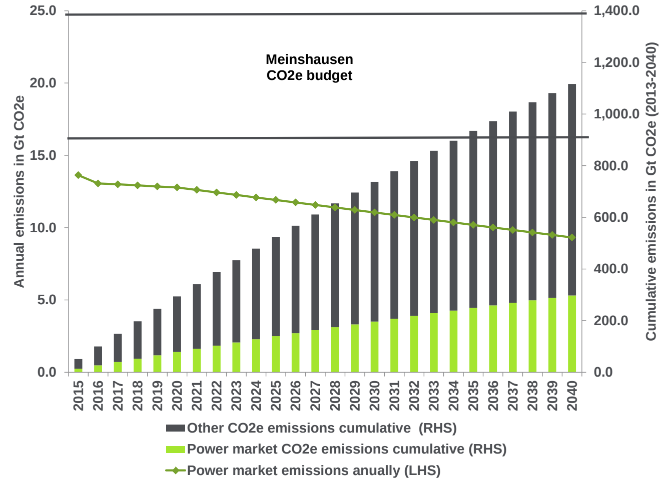
Our Citi 'Inaction' scenario implies cumulative CO_2e emissions of 500GT CO_2e between 2013 and 2040. In contrast our Citi 'Action' scenario, which assumes investments into renewables and energy efficiency, implies that this cumulative number reduces to 300GT CO_2e (Figure 67). In this scenario emissions are likely to stay flat between now until 2020 until the benefits of investments come through in the emissions data (Figure 68).

Figure 67. There is a CO_2e Discrepancy Between our Status Quo and Transformation Scenario



Source: Citi Research

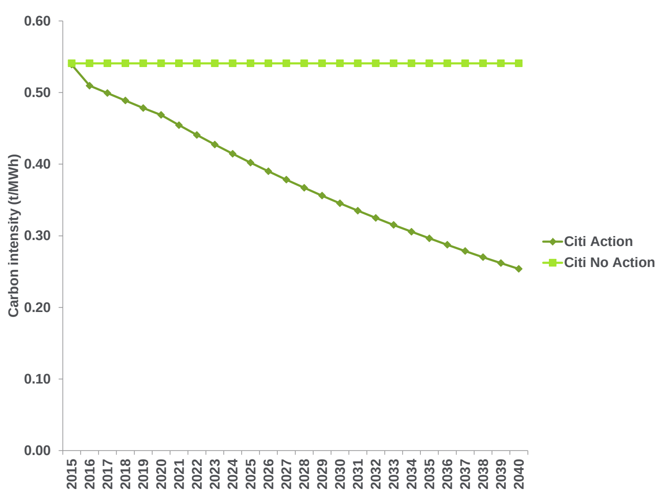
Figure 68. If Greenhouse Gas Emissions Were to Grow In Line with power Market Emissions (Citi 'Action' scenario)



Source: Citi Research

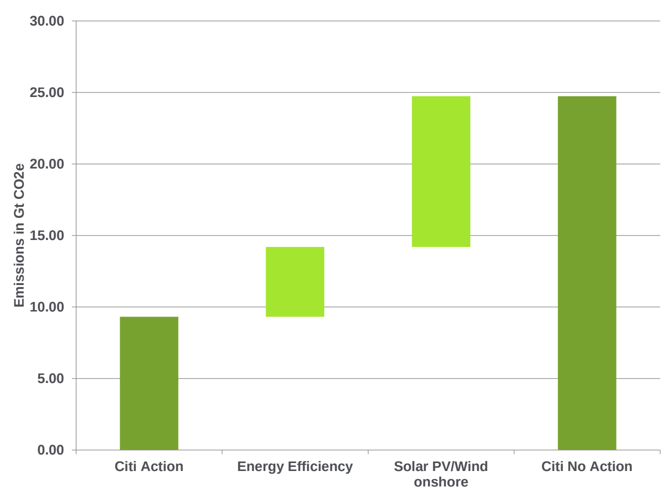
However, we highlight that the power market is not the only area where decisive action needs to be taken in order to limit climate change. For illustration, we show our cumulative emissions estimates in the power market under our 'Action' scenario in Figure 68, and assume that emissions from outside the power market such as land use, the transport market, industry etc. stay in similar proportions to what these areas emit today. The results are less encouraging, as they highlight that even tackling emissions in the power market as the single largest emitter, we still need to take decisive action in other carbon-heavy activities such as the transport market, (which we discuss in the next section), if we are not to blow through the 'carbon budget'. However, we would note that the simplistic approach to 'non-power emissions shown in Figure 68 potentially overstates their scale significantly.

Figure 69. Carbon Intensity Drops in Our Citi 'Action' Scenario



Source: Citi Research

Figure 70. Emissions in the Year 2040 – A Comparison Between Both Scenarios



Source: Meinshausen et al. (2009), Citi Research

Carbon intensity of electricity mix falls in our Citi 'Action' Scenario

In comparison with our Citi 'Inaction' scenario the carbon intensity of the electricity mix drops in our Citi 'Action' scenario from 0.54t (CO_2e)/MWh to 0.25t (CO_2e)/MWh due to the shift in electricity mix (Figure 69). Additional carbon savings are made via energy efficiency investments reducing overall electricity consumption. In 2040 we estimate that 15.4GT CO_2e per year is being saved between both our scenarios. Two thirds of these savings relate to investments into solar PV and onshore wind while the remaining third is due to energy efficiency investments.

However, it needs to be highlighted that a large gap exists in carbon intensity measured in CO_2/kWh between different regions, as seen earlier in Figure 19 and Figure 20. In emerging markets regions such as China and India, given their relative size in emissions and their coal-weighted electricity mix, carbon policy can make a greater impact.

Carbon Pricing: The Cost of Action or the Cost of Avoided Liabilities?

As discussed earlier, if it is more expensive to follow a low carbon route (which our analysis logically says that it is) then some form of incentive or penalty needs to be imposed to incentivize that low carbon behavior (or vice versa).

The most widely understood approach is by putting a 'price' on carbon emissions which dis-incentivizes countries, companies, institutions or individuals to emit carbon, thereby encouraging them to use less energy, or to generate or use lower carbon energy. Moreover a carbon price naturally directs investment towards the most cost-effective abatement projects first.

There are two different ways to think about a socially acceptable way to price carbon emissions:

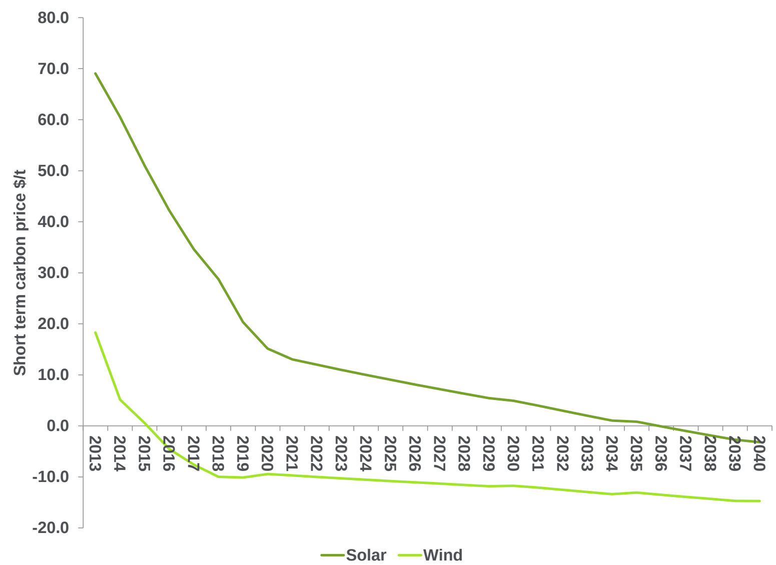
1. Analyze the investment required to reduce carbon emissions, and to tax carbon emissions accordingly to fund these investments.

2. Estimate the liabilities associated with carbon emissions and tax carbon emissions to offset those liabilities.

As seen earlier, we estimate that a transformation into a carbon-light power market could cost society 'only' an additional $1.1 trillion out to 2040. Were we simply to divide this figure by the carbon emissions, this would imply a surprisingly low implied carbon price of just $4/t of CO_2 needed to fund the power market transition between both our Citi scenarios. This figure is so low because as renewable energy becomes cheaper than conventional in later years, there is effectively a net saving to using it, and hence simplistically a 'negative' carbon price in later years which is clearly non-sensical. Moreover, a carbon price that 'reduces' over time is also counterintuitive. Clearly if a carbon price incentivizes an entity to address the most cost-effective abatement opportunities first (the "low-hanging fruit") then by definition as each ton abated becomes more expensive, a higher carbon price would be needed to incentivize that action. Hence, we recognize that a differentiated carbon price might be needed at different points in time (depending on progress) and across different regions in order to incentivize investment into renewable power and 'fund' a lower carbon future.

In practical terms, in earlier years when particularly solar PV is more expensive than conventional fuels, society would need to impose carbon prices which are high enough to level out the playing field. With the rapid fall in the cost of electricity from renewables we anticipate solar PV to be competitive with conventional fuels by 2030 and hence there is theoretically no need for further incentives via a carbon price in the power market alone, as shown in Figure 71.

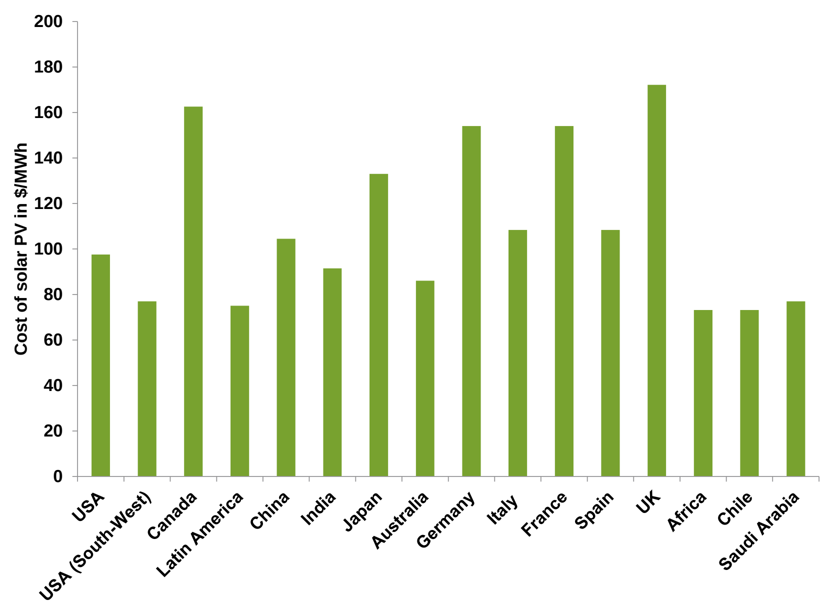
Figure 71. Short-Term Carbon Price Required to Incentivize Investment



Source: Citi Research

It is important to highlight though just how much the economics of renewable energy varies across the world. For example the cost of solar PV electricity is very sensitive to sunshine, which varies drastically across regions (Figure 72).

Figure 72. Solar PV Cost of Electricity Generation Across Different Regions – Citi Projections for 2015



Source: Citi Research

Therefore, the speed of investment and deployment are likely to vary geographically at any given carbon price. As discussed earlier in this report, we view a single 'global' carbon price (or market) as being an unlikely outcome from COP21 in Paris, rather that countries will adopt their own mechanisms based on their own energy demand, growth, mix and resources, mechanisms which may or may not be inter-tradable via mechanisms such as the CDM or JI.

A Word on the Potential of Solar and Energy Storage

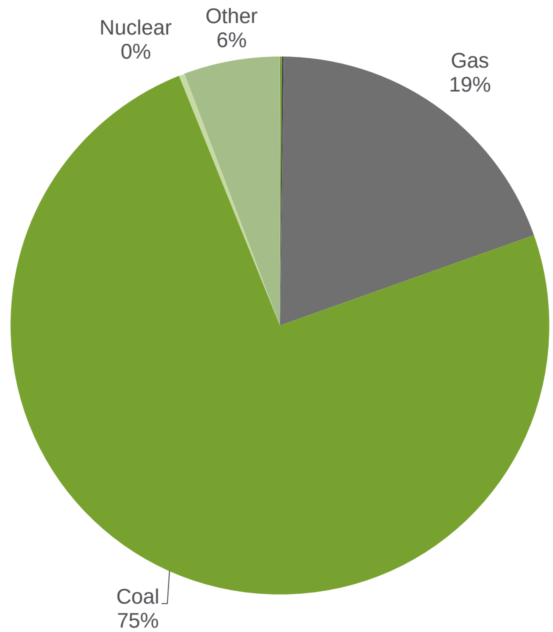
Solar is already competitive at the domestic level in various countries where irradiation (sunlight levels) and residential rates are high. Solar has almost zero variable cost, with most of the cost upfront capex. In our first Energy Darwinism report, we highlighted a case study of Germany which showed how annual solar installations grew from 1GW in 2007 to 7.4GW in just three years. The problem with the expansion of solar (and a criticism of the LCOE approach) is that solar only generates electricity at certain times and therefore conventional plants are still required to cover the demand at other times. This intermittency is the key drawback to solar making storage the 'holy grail' to the solar story; in the longer term it could have an even more dramatic impact on the electricity markets (for more information refer to Battery storage – the next solar boom? and Energy Darwinism II).

Battery storage is starting to become a reality, with the introduction of Tesla's Powerwall, a wall-mounted rechargeable lithium-ion battery. According to Tesla, the battery is designed to enable load shifting by charging during times when demand is low, and discharging when demand is high. The battery can also store solar power generated during the daytime for use at night. It is available at 7kWh or 10kWh and the costs start at an estimated $3,000. The jury is still out on the economics of the product, with it being more economical in certain countries. However, since Elon Musk's announcement on the 30th of April, Tesla has taken orders worth roughly $800 million in potential revenue (Source: Bloomberg - Tesla's Battery Grabbed $800 Million in its first week). Even if you disagree with the economics, it is hard to deny the fact that energy storage could have a huge impact on the electricity market with an increase in investment in solar over the next decade. This technology could be enormously disruptive for utility companies, as highlighted extensively in previous publications such as Let the Survival Game begin as Lost Decade Takes Hold.

Fossil Fuels

Coal-fired plants are the largest single emitters in the power market, making up 40% of the current energy mix. However, coal's high abundance and low price has historically made it the fuel of choice for many countries. In terms of LCOE coal currently represents the most competitive source of electricity generation.

Figure 73. Coal Emits Nearly Three-Quarters of All GHG Emissions in the Power Market



Source: Citi Research

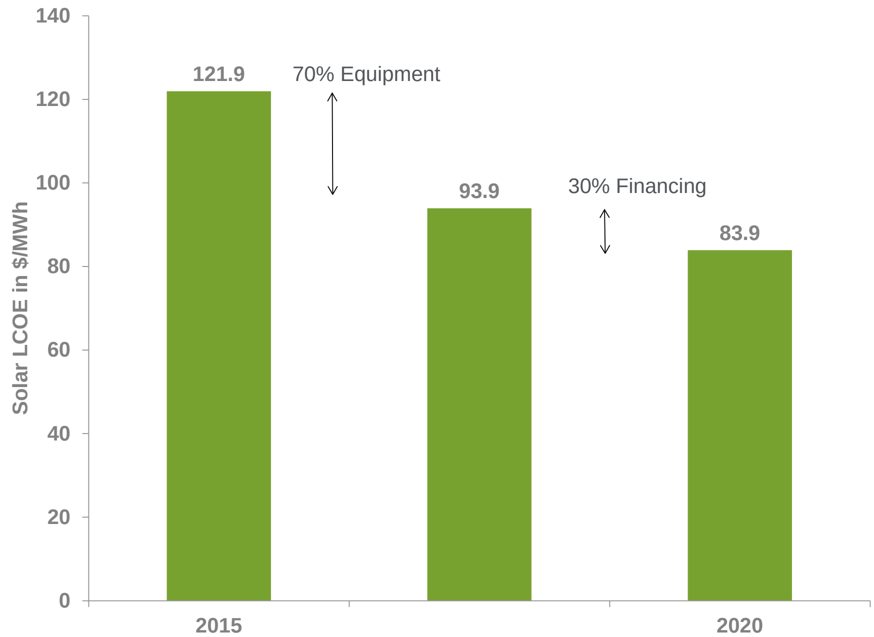
Since coal is the most carbon-heavy fuel, a tax on CO_2 emissions would have a material effect

Given coal is also the most carbon-heavy fuel, any carbon price imposed on emissions would impact the economics of the coal-fired plants the most, whilst gas plants would be less affected by a carbon tax due to their lower carbon emissions per terawatt-hours (TWh) produced.

Global Power Market Outlook 2020: Updating the Energy Darwinism Curves

Since our Citi GPS Energy Darwinism report in 2013, one of the most striking developments in power markets has been the emergence of yield vehicle structures (yieldcos) which finance project equity; this development has reduced the cost of capital for renewables projects significantly.

Figure 74. LCOE Decline Driven by Equipment Cost Reductions and Financing Cost Reductions



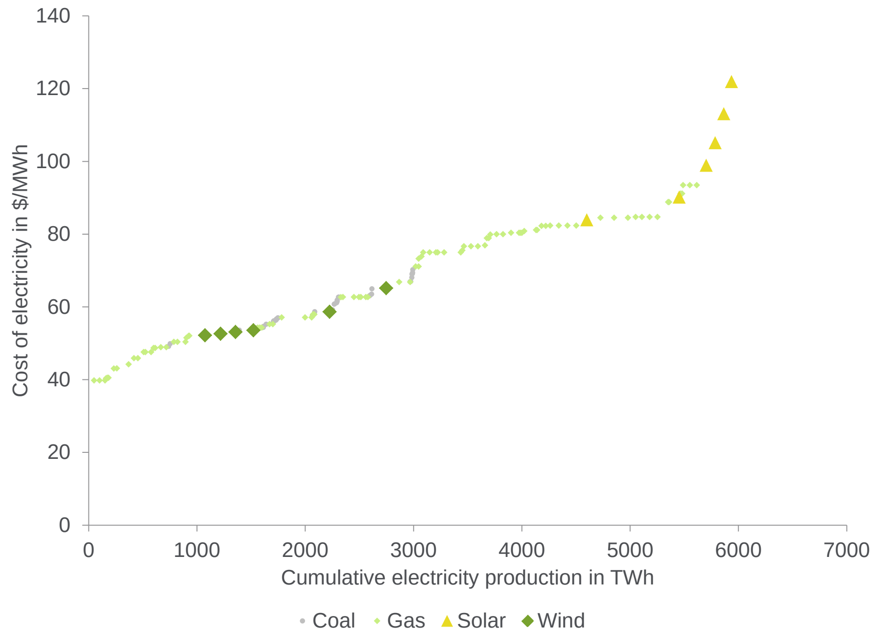
Source: Citi Research

Yieldco's could drive down the cost of capital in the renewable space

We anticipate that the acceptance of yieldcos in the renewables space will further drive down cost of capital via two channels: (1) reducing cost of equity as more equity and income investors become comfortable with the yieldco risk profile and (2) project developers and equipment providers building a track record under the public eye. This development could also reduce spreads on debt project financing. We estimate that the weighted cost of capital for renewables projects can be reduced by another 1% by 2020 down to 4% leading to further reductions in cost of capital.

Our updated 'Energy Darwinism' curve is shown in Figure 75; for a full understanding of how this integrated global energy cost curve is derived, and its implications see the original 'Energy Darwinism' report.

Figure 75. Updated 2020 Energy Darwinism Curve

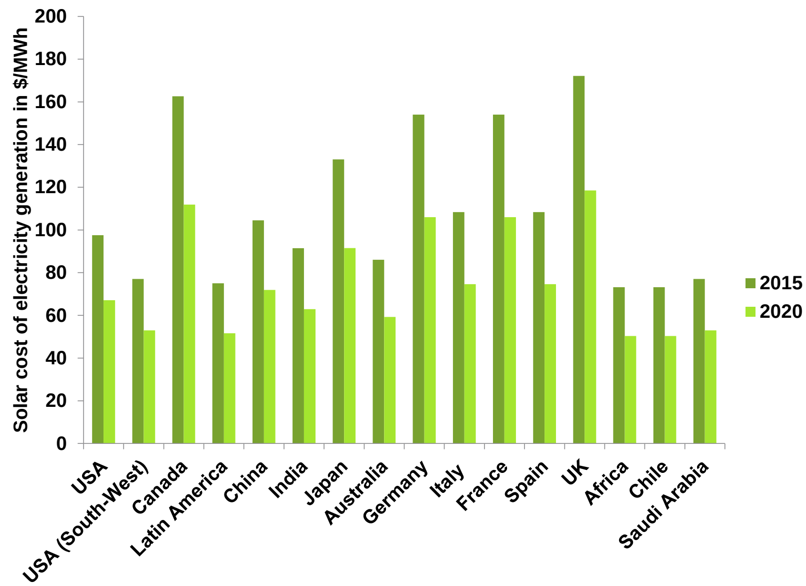


Source: Citi Research

In 2020, we anticipate wind energy to be fully competitive with conventional fuel, even on supercritical coal capex and efficiency assumptions. Gas is very sensitive to the cost of gas extraction per project - at the lower gas band around $1-$2.50/MMBtu it becomes difficult for wind to compete.

While better financing conditions provide a boost to the solar cost of electricity generation and competitiveness by 2020 we still anticipate solar costs to be above $80/MWh. However, solar energy costs are very sensitive to irradiation with notable regional differences; in very sunny regions such as Africa, Chile, and Saudi Arabia, solar could compete on competitive terms with (unsubsidized) conventional fuels. (See Figure 76)

Figure 76. Solar LCOE Across Regions



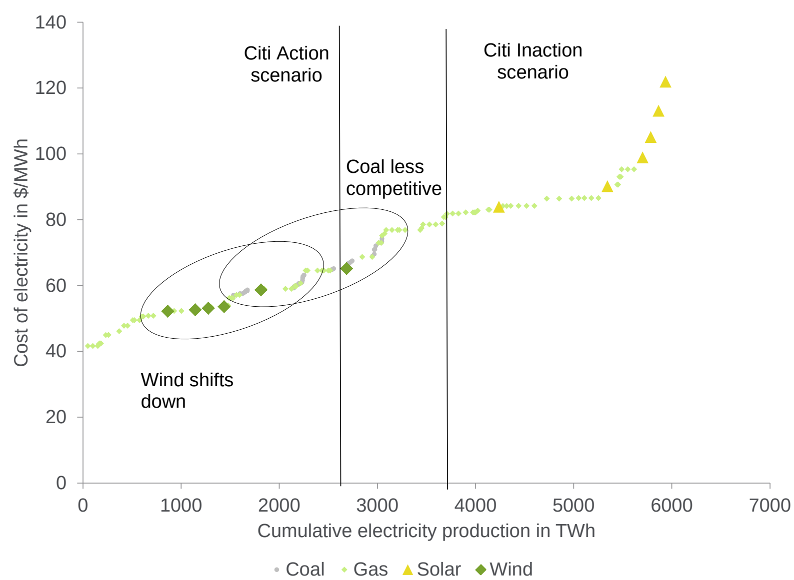
Source: Citi Research

Carbon Pricing: Game Changer for Coal?

Coal would be mostly affected by a carbon price of $4 tonne of CO_2

If we were to overlay the very low $4/t carbon price over our original energy Darwinism curve we find that the coal section of the curve is unsurprisingly most affected. Coal has the highest emission ratio per unit of energy production and a carbon price of $4/t would shift the coal projects on the curve up by about $4/MWh. This would render many coal projects less competitive against low cost gas and wind power. As outlined in our long term/short term carbon price discussion many solar projects would still be uncompetitive at these carbon prices.

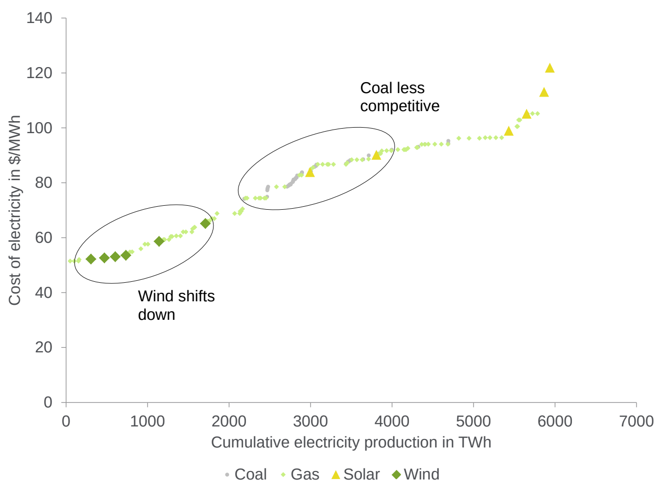
Figure 77. Darwinism Curve with Minimal Carbon Pricing



Source: Citi Research

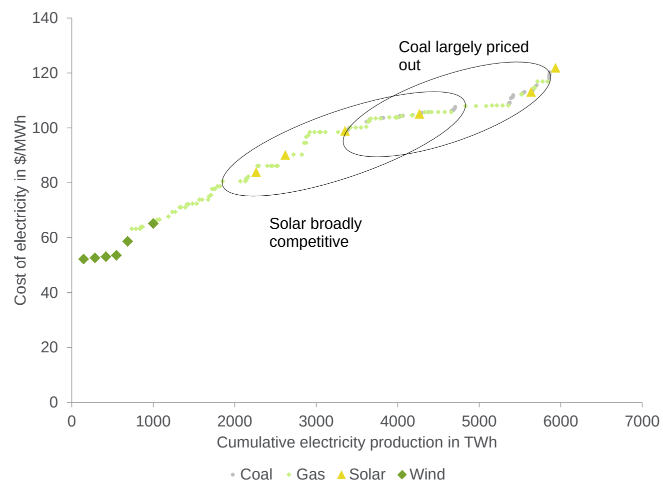
A more relevant scenario would be to apply shorter-term carbon prices to the Energy Darwinism curve. Figure 78 and Figure 79 show the Darwinism cost curves with a $25/t and a $50/t carbon price. As before, coal is impacted most negatively impacted becoming amongst the most expensive generation options at $50/t, and a questionable choice at $25/t, especially given the life of a coal plant is potentially 40 years. Gas continues to span the length of the curves, though clearly assets at the upper end of the curve are pushed even further up the curves. Obviously wind and solar are the big beneficiaries, with wind in particular becoming the lowest cost option at $50/t (and amongst the lowest at $25/t). Solar remains expensive, though at $50/t moves into the second quartile of the cost curve.

Figure 78. Energy Darwinism Cost Curve Out to 2020 at a Carbon Price of $25/t



Source: Citi Research

Figure 79. Energy Darwinism Cost Curve Out to 2020 at a Carbon Price of $50/t



Source: Citi Research

We would highlight that these curves only incorporate incremental energy assets potentially coming onstream between now and 2020, and hence there are only five years of cost reductions shown for solar. Given the dramatic learning rates of around 20% discussed earlier for solar, as time goes on, solar should continue to aggressively reduce in cost, and longer term curves are likely to see solar continue its inexorable move down the curve.

As discussed in the original energy Darwinism report, significant quantities of conventional assets at the upper of the cost curve are in our opinion likely to become stranded. Adding a material cost of carbon to energy will only exacerbate this issue, and is likely to 'strand' a significantly greater proportion of conventional assets, and issue examined in much greater detail in a later chapter.

Drivers of Change (2): Energy Efficiency

Highlights

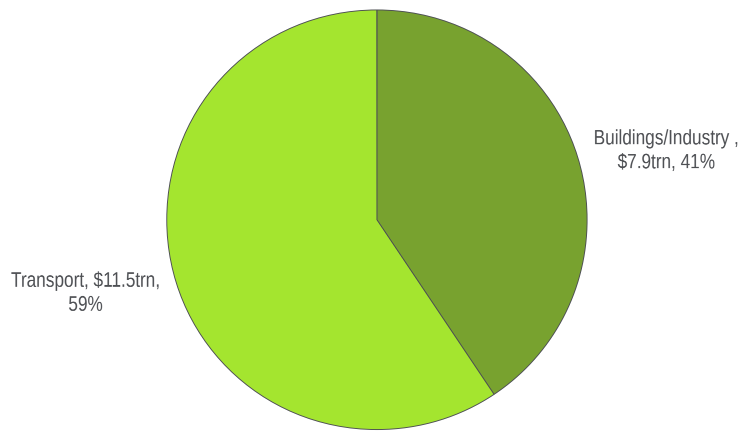
- Our Citi 'Action' scenario entails a total spend on energy efficiency of $19.4 trillion between 2015 and 2040, almost two thirds of which we expect to take place in the transport sector.
- Transportation emissions were estimated at around 7GT of CO_2e per year, representing approximately 14% of total GHG emissions in 2010, and 23% of total energy-related CO_2 emissions in 2013. The majority of the emissions are related to the oil used in road transport.
- Transport emission regulations are being widely adopted, with increasingly stringent miles-per-gallon targets being set globally.
- These efficiencies are expected to be achieved via technological advances such as turbochargers, direct injection, start/stop systems, thermal management, lightweight materials, low resistance tires and transmission technologies.
- BP estimates that energy efficiency measures could result in only a 30% overall increase in fuel usage, despite a potential doubling of vehicle fleets.
- While oil is likely to continue to dominate transport fuels out to 2035, other propulsion technologies such as fuel cells, natural gas, and electric vehicles/hybrids are also likely to play an increasing role in reducing emissions. The imminent launch of new models using alternative technologies from several high profile manufacturers could also add a boost to rates of adoption that have so far been relatively slow.

Transport-Related Emissions

An $11.5 trillion investment would be required in the transport sector

While the previous chapter on the power market transformation touched on the associated energy efficiency spend, 60% of the $19.4 trillion investment in energy efficiency between 2015 and 2040 in our 'Action' scenario will occur in the transport segment (Figure 80). In this chapter we examine that investment and its implications.

Figure 80. Energy Efficiency Spend Between 2014 and 2040 by Activity



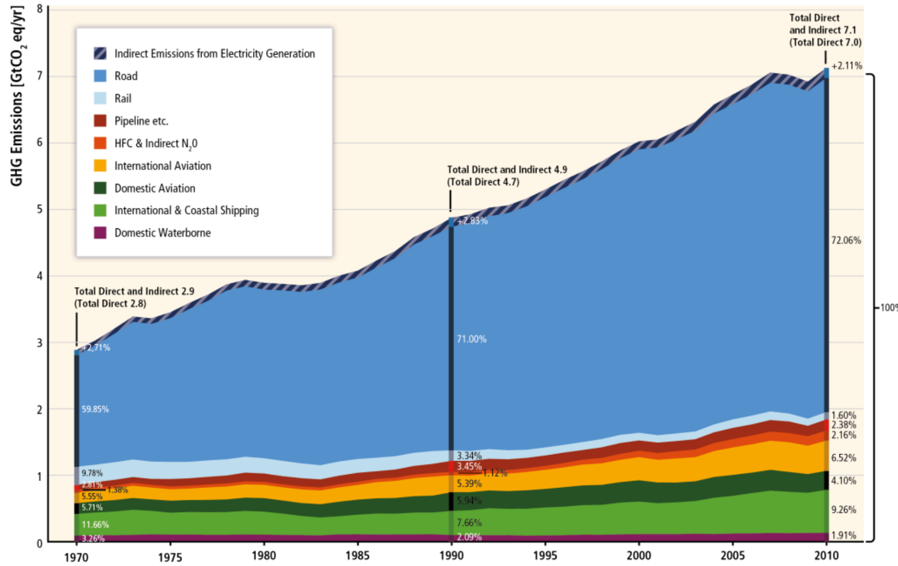
Source: Citi Research

Energy efficiency policies, especially in transport, should be considered an extremely important mechanism for meeting climate change objectives. These relate to actions such as investments in low resistance tires, lightweight materials and direct fuel injection; however energy savings from fuel switching (for example from using an electric vehicle rather than a gasoline one) are not counted as an energy efficiency investment, even though in practice they do increase the overall efficiency of the system.

In 2010, GHG emissions from the transport sector were estimated at 7GT CO_2e. Emissions from this sector, dominated by oil for road transport, have increased by 1.7% per year on average since 2000, but with different underlying regional trends.[15]

[15] IEA (2013)

Figure 81. Transport- Related Greenhouse Gas Emissions from 1970 to 2010



Source: Sims at al. (2014)

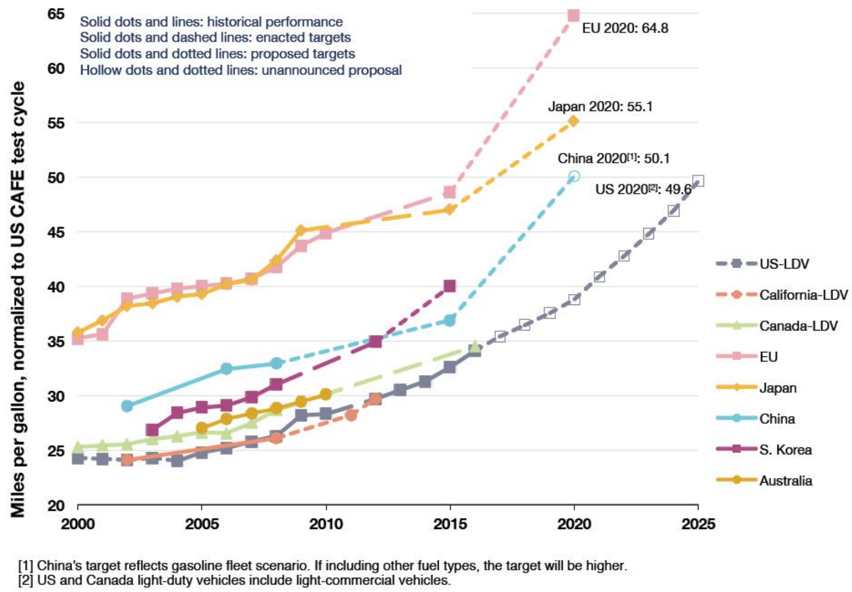
The transport sector has seen a substantial increase in global growth in the past two decades, in the form of increased vehicle ownership and energy use in all transport sectors. However to help mitigate the environmental impacts, many countries have developed transport sector policies to improve the energy and environmental performance of vehicles and fuels. Citi has undertaken a detailed analysis on how regulations on fuel economy and the transport sector in general are changing the market for energy efficiency engine technologies.

Are Emissions and Fuel Targets Propelling the Car of the Future? Which Technologies are Estimated to Grow?

Emissions regulations in the transport sector are expected to increase over time

The introduction of regulations together with changes in consumer demand has compelled automakers to pursue development strategies that focus on fuel economy and a reduction of emissions. Figure 82 below shows the emissions regulations including historical performance together with enacted and proposed targets in different regions up to 2025.

Figure 82. Emissions Regulations: Gram CO_2 per kilometer to 2025

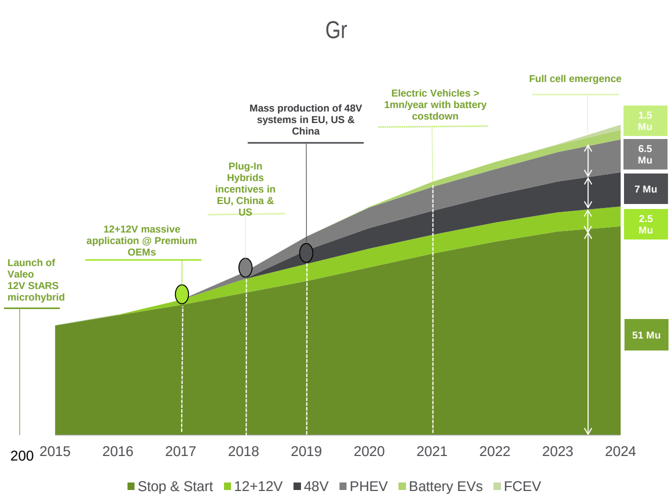


Source: International Council on Clean Transportation, Citi Research

‘Workhorse’ powertrain technologies will provide the high growth in transport-related energy efficiency sector

These global regulatory regimes are generally in place up to the latter part of this decade. However, even when taking into consideration the significant strides that have already taken place in emerging markets, we believe that many of the high-growth opportunities in transport-related energy efficiency will likely come from “workhorse” powertrain technologies. Figure 83 and Figure 84 below show the proposed growth in engine technologies together with the CO_2 savings and market growth potential of different engine and transmission technologies.

Figure 83. Growth in Engine Technologies



Source: Valeo

Figure 84. Overview Technologies, CO_2 Saving and Market Growth Potential

	Technology	CO2 Saving	Market Growth (2014-2024)
Efficient Engines	Turbochargers	10%	6%
	Direct Injection	10% - 20%	9%
	Variable Valve Timing	1% - 5%	8%
	Thermal Management	Significant	27%
	New Combustion Techniques	Slight	21%
Efficient Transmissions	Automatic Manual Transmissions	7%	8%
	Electric Clutch	7%	10%
	Dual Clutch Transmissions	10%	12%
	Continuous Variable Transmissions	7%	4%
Efficient Engines	Stop Start	7%	11%
	Mild Hybrid	25%	36%
	Full Hybrid	40%	17%
	Plug In Hybrid	70%	33%
	Electric Vehicle	100%	18%

Source: Company Data, Citi Research

Direct injection and start/stop systems can reduce CO_2 emissions by an extra 10-20%and 7% respectively

An example of an efficient engine is a direct injection system which allows fuel to be injected into the engine combustion chamber at a highly pressurized level thereby controlling more precisely the amount and timing of fuel directed into the engine, rendering the engine more efficient. Direct injection often works with turbochargers, reducing CO_2 emissions by an extra 10-20%. European auto-parts manufacturer Valeo believes that gasoline direct injections engines should have a compound annual growth rate (CAGR) of around 9% to 2024. Penetration rates are currently about 30-35% in Europe and 31% in North America. Other examples include Start/Stop systems which could reduce CO_2 emissions by 7%, and thermal management which relates to the monitoring and influencing of the heat of the engine which can contribute significantly to the dynamics and, as a result, has the potential to be one of the fastest growing areas for powertrains (CAGR of ~27% as estimated by Valeo). Advances in transmission technology such as automated manual transmissions and dual clutch transmissions are also instrumental to the improvement in fuel economy for internal combustion engines. For more information on different engine and transmission technologies please refer to Citi GPS report Car of the Future II.

Figure 85. Companies Involved in Efficient Transmission Technologies

"Workhorse" Technologies		Transmission Technologies	
Product Category	Select Companies involved	Product Category	Select Companies involved
Direct Injection	Delphi, Continental	Automated manual transmissions	Aisin, BorgWarner
Low Resistance Tires	Continental, Bridgestone, Goodyear, Michelin	Continuously variable transmissions	Aisin, JATCO
Turbochargers	Honeywell, BorgWarner, Cummins, IHI, MHI	Dual clutch transmissions	Aisin, BorgWarner, Getrag, ZF
Variable Valve Lift & Timing	BorgWarner, Denso		
Thermal Systems & HVAC	BorgWarner, Mahle, Visteon, Denso, Delphi		
Torque Transfer (Driveline)	American Axle, Magna, BorgWarner, GKN, JTEKT		
Stop/Start	Johnson Controls, Denso, Valeo, BorgWarner		

Source: Company Reports, Mezler Engineering Services, Citi Research

Non-Conventional Technologies: Can these Technologies Grow in the Near Future?

A key question is whether non-conventional technologies such as electric vehicles (EVs), fuel cells and compressed natural gas (CNG) vehicles can also make sufficient advances, gain acceptance, and cause a market tipping point. We think that due credit should be given to these unconventional technologies; however, it is important to highlight that disruptive change in the automotive industry does not occur overnight, given long product cycles, capacity requirements and high costs.

Zero-tailpipe emissions could be an important selling point of electric cars especially in countries with high air quality pollution.

From an operating cost perspective, EVs remain superior with a fuel cost-per-mile of only $0.04, which is lower when compared to CNG ($0.07) and conventional gasoline cars, even at current prices. EV's offer maintenance savings from the absence of required oil changes, and have improved performance thanks to their unique torque characteristics. Even though there have been debates about well-to-wheel emissions, the zero tailpipe emission selling points of these vehicles are a powerful consideration for both consumers and regulators. Costs, long charging times and infrastructure remain the greatest barriers to mass adoption, even with tax incentives. While sales of lower-priced US electric cars have been tepid over the years, the major test for EVs will be held in 2017 with the debut of electric cars from Tesla and GM, both of which are targeted at the mass market level. While the US may not have seen huge successes so far, in other markets where taxes on motor fuels are significantly higher, there have been greater success stories for EVs. In Norway for example, 1% of the car fleet is now electric.

Battery technology advancements could increase the uptake for EV's

Whilst skeptics will point to the slow pace of battery technology advancements as proof of the future low uptake for EV's, we think that the outlook for these technologies remains bright, though we do acknowledge that the ramp up would probably be slow (still <2% in most markets by 2020). We believe that the race of EVs is very much still on especially if we look at the competitive environment of participants including Tesla, BMW, Nissan and GM. The uptake of EVs is also likely to differ regionally; for example there is currently strong government support for EV's in China, with the government subsidizing more on the BYD E6 than the US government is on Tesla Motors. Even though the oil price has plunged recently, the Chinese government remains committed to reducing its reliance on oil imports and become more energy secure. EVs are not only a solution to this issue, but also form part of the solution to reducing air pollution in China, a key focus for the Chinese government.

There are parallels between the EV market and the solar industry a decade ago; few would have predicted at that time the speed of cost reductions or the level of penetration which solar has achieved. However, as that industry has proved, with the right incentives and investments, industries can change rapidly, and we believe that the EV and battery market offer similar potential to surprise on the upside.

Other fuel switching technologies such as CNG and hydrogen fuel cell systems are also currently being discussed as possible solutions to reduce transport related emissions. CNG is at present confined mainly to commercial fleets, though a small volume of light duty vehicles utilize a bi-fuel approach (gasoline or natural gas can be used to fuel the vehicle). The Boston Consulting Group believes CNG light vehicle volume in the US could grow to over 300,000 vehicles by 2020, up from around 100,000 in 2014. CNG offers a number of advantages including energy security for gas producing countries such as the US, low cost fuel and a 20-30% reduction in CO_2 emissions compared to gasoline cars. The most glaring challenges are infrastructure requirements, energy density and a large cost premium (refer to Citi GPS: Energy 2020: Trucks Trains and Automobiles).

CNG and fuel cell technologies such as the new Toyota Mirai could also have an effect on CO_2 emissions from the transport sector

With regards to fuel cell technologies, the spotlight is on the Toyota Mirai, which was announced at the end of 2014 and should come to market in late 2015. The Mirai takes the electricity created from the chemical reaction in the fuel cell stack between hydrogen and the oxygen in the air, raises its voltage in the fuel-cell boost converter and powers a motor with it. The Mirai costs are lowered as it can use the motors and batteries shared with hybrid cars, annual sales of which exceed 1 million units. Currently, hydrogen is generally extracted from fossil fuels and CO_2 is therefore produced in the manufacturing process. So in order to be called the ultimate 'eco-friendly car' it is imperative that a hydrogen supply system that is CO_2 free is developed. Shell believes that by the end of the century, roads will be almost oil-free and there could be an extensive hydrogen network as wide as the petrol/gasoline infrastructure today serving a majority-hydrogen fleet. This is partly because of the abundance of hydrogen in the atmosphere and because hydrogen cars have a driving range and refueling time equal to gasoline powered cars. They are also lighter than current EVs which are equipped with large batteries (refer to Citi GPS: Car of the Future.

Figure 86. Comparison of Gasoline Engine, HEV, PHEC, EV and FCVs

	Gasoline Engine	Hybrid Electric Vehicle (HEV)	Plug-in Hybrid Electric Vehicle (PHEV)	Electric Vehicle (EV)	Fuel Cell Vehicle (FCV)
CO_2 Emission (Gasoline engine=100)	100	60-75	30	0	0
Safety	◎	Fire (low risk)	Fire (high risk)	Fire (high risk)	Gas explosion
Price ($)	◎	16,000>	30,000>	20,000	50,000？
Battery amount (kWh)	Unnecessary	0.8-1.3	5-15	15-25	Estimated to be same to HEV
Battery power	Unnecessary	Strong	Strong	Modest	Modest
Driving range (Km)	more than 500km	more than 500km	more than 500km以上	200km	more than 500k
Charging time	Unnecessary	Unnecessary	Good	Bad	Unnecessary
Infrastructure	Gas station	Gas station	Gas station Charging station	Charging station	Hydrogen station

Source: Company Data, Citi Research

The successful adoption of fuel cells could depend on the investment in required infrastructure.

We believe that fuel cell vehicles are unlikely to take off for over a decade due to cost and infrastructure requirements. According to Fiat, building the infrastructure for fuel cells could cost up to £50 billion ($78bn) in a country the size of the UK. While that is a large number in absolute terms, in the context of the trillions of dollars being discussed in this report it is relatively small. The US Energy Information Administration (EIA) states that by 2025 sales of fuel cell cars could be no more than 0.05% of total number of cars sold. However, this view is not shared by Toyota, as they believe that fuel cells costs will be cut in half by 2020. That said, by 2030, we believe that sales could pick up and significant growth could be driven by regulations such as the Zero Emission Vehicles Regulation in California, which mandates that 22% of sales of cars by 2025 must be either plug-in hybrids of fully electric/hydrogen cars.

Will a Low Oil Price have an Effect on Energy Efficiency Investment in Transport?

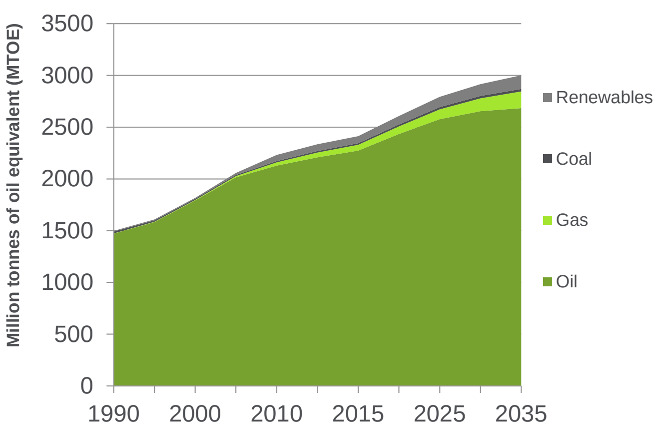
With average gas prices at the pump sliding below $3 per gallon in the US and vehicle mix moving back in favor of larger trucks and SUVs, it seems a good time to discuss US Corporate Average Fuel Economy (CAFE) requirements that will be examined as part of the CAFE 'mid-term' review set to take place in 2017. The aim of the review is to evaluate the feasibility of current fuel economy/emissions plans out to 2025. Industry observers wonder whether the stricter standards that ultimately lead to 54.5 miles per gallon by 2025 may be lowered or delayed if lower energy prices continue or government urgency over this matter changes. It appears to us that the substance of the debate would focus on the years 2022-2025 of the program and what the mid-term review can accomplish is to allow automakers to argue for the loosening of this second phase of CAFE standards. Proposals could range from scaling back decade fuel economic targets while introducing stricter, farther out mandates. This could delay the investment in energy efficiency in the US, but ultimately it would not deter it in the long-term. Of course, a new US presidential administration will be in place by the time of the review and that administration's receptiveness (or lack thereof) to the current plans could represent one of the largest variables in the expected outcome.

What Does This All Mean for Future CO_2 Emissions from the Transport Sector?

Efficiency gains in the transport sector would limit fuel transport demand

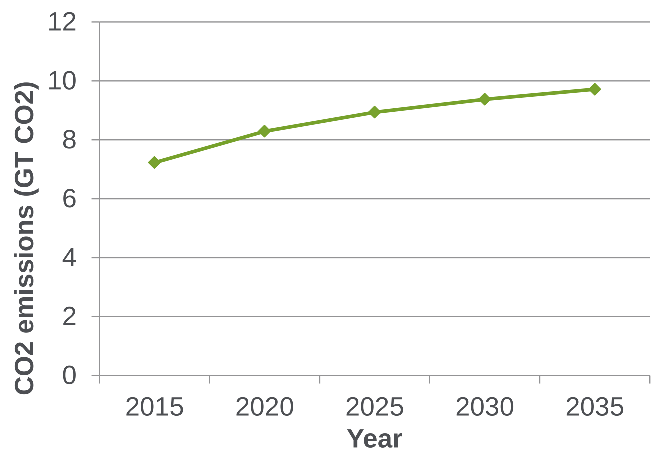
According to BP's Energy Outlook Report, efficiency gains in the transport market could limit the growth in transport fuel demand, with transport demand only increasing by 30% despite a more than doubling of vehicle fleets from 1.2 billion today to 2.4 billion in 2035. They estimate that fuel economy and efficiency gains are likely to accelerate and improve at approximately 2.1% per year between 2013 and 2035 and estimate that oil will continue to be the main transport fuel (89% in 2035), however the share of non-oil alternatives would increase from 5% in 2013 to 11% in 2035, with natural gas estimated to be the fastest growing transport fuel (Figure 87). Even with fuel efficiency improvements of 2.1% per am, this scenario would lead to an increase in CO_2 emissions from 7GT in 2013 to just above 9.5GT of CO_2 in 2035 as shown in Figure 88. This analysis uses IPCC carbon emission factors for different fuels and assumes that the same % mix of gasoline and diesel that is used today is used in the future.

Figure 87. Transport Demand by Fuel Type



Source: BP Energy Outlook, 2015

Figure 88. Transport-related CO_2 emissions based on a 2.1% improvement in energy efficiency and BP's transport fuel mix



Source: Citi Research

Obviously without fuel efficiency improvements, CO_2 emissions would increase at a faster rate, so legislation such CAFE does make a difference. However fuel mix, is also important. For example natural gas is 25% less carbon intensive than diesel (emission factors for CNG and diesel is 56,100 kg/TJ and 74,100 kg/TJ respectively).

Implications (1): Stranded assets

Highlights

- Switching to a low carbon energy future means that significant fossil fuels that would otherwise have been burnt will be left underground. The development of the so called 'carbon budget' has led to the concepts of 'unburnable carbon' and associated 'stranded assets'.

- Emissions contained in current 'reserves' figures are around three times higher than the so called ‘carbon budget’. Some studies suggest that globally a third of oil reserves, half of gas reserves and over 80% of current coal reserves would have to remain unused from 2010 to 2050 in order to have a chance of meeting the 2°C target.

- In financial terms, we estimate that the value of unburnable reserves could amount to over $100 trillion out to 2050. The biggest loser stands to be the coal industry, where we estimate cumulative spend under our Action scenario could be $11.6 trillion less than in our Inaction scenario over the next quarter century, with renewables, wind and nuclear (as well as energy efficiency) the main beneficiaries. While gas suffers a smaller reduction it is still potentially impacted.

- In this chapter we examine the effect on the oil, gas and coal industries, and in particular which assets (typically those at the upper end of the cost curves) which are most at risk of not being developed/used.

- The one potential game changer for the coal industry comes in the form of Carbon Capture and Storage (CCS); while expensive now, if this can be made economically viable, it could carbon-enable huge potential resources. However, the industry is, in our opinion, in a something of an existential race to develop CCS within its survivability timeframe.

- Investors are becoming increasingly active and engaged on the issue of stranded assets, with actions varying from carbon footprinting, realigning portfolios, increasing engagement with fossil fuel companies, or at the extreme banning investments in certain types of companies.

- Stranded assets and unburnable carbon are becoming a significant issue for countries, industries, companies and investors, and focus provided by COP21 in Paris and beyond is only likely to increase attention.

Introduction

One of the major implications of changing to a lower carbon mix, is the amount of fossil fuels that potentially won't be burnt that otherwise might have been. These concepts of “unburnable carbon” and “stranded assets” started to gain broad traction in the investment community in 2012 and 2013, largely driven by analysis from the IEA which stated that:

"No more than one-third of proven reserves of fossil fuels can be consumed prior to 2050 if the world is to achieve the 2°C goal, unless carbon capture and storage (CCS) technology is widely deployed. … Almost two thirds of these carbon reserves are related to coal, 22% to oil and 15% to gas. Geographically, two thirds are held by North America, the Middle East, China and Russia."

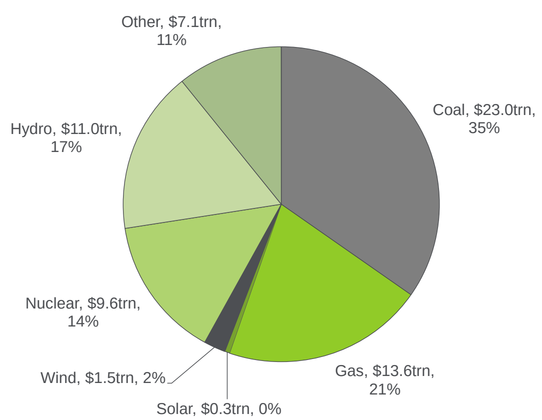
The Risk for Fossil Fuel Producers

Coal is the clear loser under a low carbon scenario

Figure 89 and Figure 90 demonstrate the significant changes in the split of investment in power generation and associated fuel costs between 2015 and 2040 under our two scenarios. The clear loser between the scenarios is coal, which sees its total investment bill fall by some $11.5 trillion over the next quarter century. Gas investment also reduces though by a far smaller amount, $3.4 trillion in total, reflecting the attractions of gas as a lower carbon transition fuel, given its significantly lower emissions per MWh vs. coal.

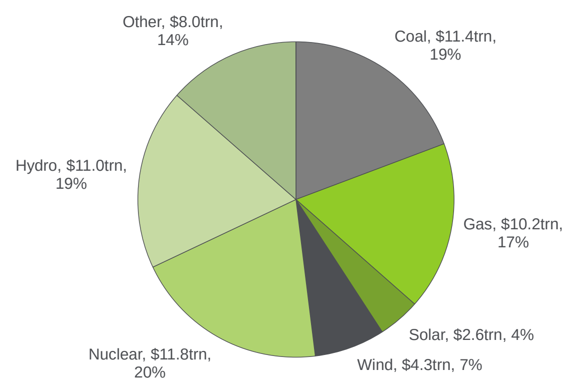
The beneficiaries of the mix shift are unsurprisingly wind and solar which see their investment totals increase by $2.8 trillion and $2.2 trillion respectively. Nuclear is also a beneficiary, with investment increasing by $2.2 trillion over the period. 'Other' reflects generation technologies such as biomass, geothermal, solar thermal, tidal etc., which collectively also see an increase in investment of $0.9 trillion.

Figure 89. Total Spend on Electricity Using an LCOE Approach in Citi's 'Inaction' Scenario. (Total Spend = $66.1trn)



Source: Citi Research

Figure 90. Total Spend on Electricity Using an LCOE Approach in Citi's 'Action' Scenario. (Total Spend = $59.4trn)



Source: Citi Research

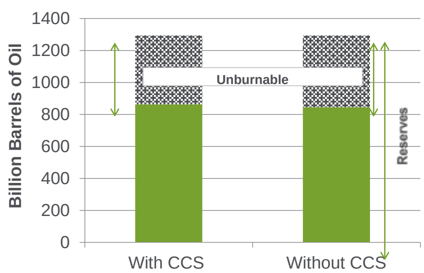
Accordingly, investments in the coal industry (by both companies and investors) based on an assumption of 'business as usual' clearly face higher risks, and in our opinion should be stress tested against either a lower coal demand scenario, and/or one which incorporates a significant carbon price.

While early analysis of unburnable carbon and stranded assets tended to focus largely on the overall proportion of reserves that would be unburnable, greater recent alignment with the investment community has highlighted the risks presented by the potential devaluation of fossil fuel assets. As the original Energy Darwinism report highlighted, an increased focus on the economic viability of potential projects at the upper end of the industry cost curves, either due to lower/different usage profiles or via the impact of a cost of carbon, has encouraged investors to engage with companies about the allocation of capital to such projects. To look at it a different way, the increased risks of non-usage/carbon pricing effectively raises the cost of capital of such projects, potentially thereby making them unviable.

Globally a third of oil reserves, half of gas reserves and over 80% of current coal reserves could be stranded

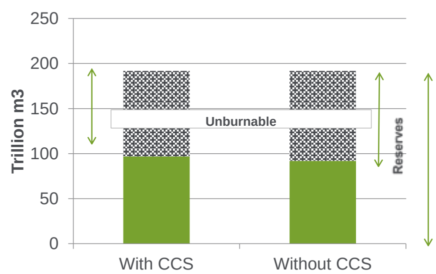
A 2015 report in *Nature* by McGlade and Ekins[16] summarizes the current thinking on 'carbon budgets', and goes on to assess the geographical distribution of fossil fuels that might be unused in a 2°C scenario. The study states that for a 50% chance of limiting warming to 2°C, cumulative emissions between 2011 and 2050 must be limited to ~1,100 gigatonnes of CO_2. Figure 91, Figure 92 and Figure 93 present the findings of this study with estimates of fossil fuels left unburned under two scenarios (a) without CCS and (b) with CCS. Reserves in figures below are defined as a subset of available resources that can be recoverable under current economic conditions and which have a specific probability of being produced. Emissions contained in present estimates of fossil fuel reserves are around three times higher (~2,900GT) than the 'carbon budget', while consumption of all estimated remaining fossil fuel resources would generate emissions of ~11,000GT. The results show that globally a third of oil reserves, half of gas reserves and over 80% of current coal reserves would have to remain unused from 2010 to 2050 in order to have a chance of meeting the 2°C target.

Figure 91. Total and Unburnable Oil Reserves



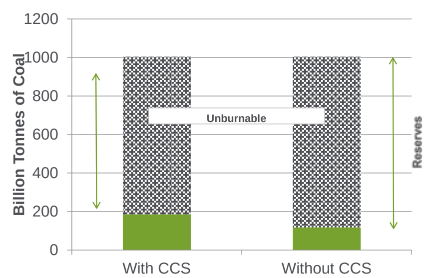
Source: McGlade et al. (2015),Citi Research

Figure 92. Total and Unburnable Gas Reserves



Source: McGlade et al. (2015), Citi Research

Figure 93. Total and Unburnable Coal Reserves



Source: McGlade et al. (2015), Citi Research

However, volumetric figures of barrels, cubic meters and tonnes are not easy to conceptualize. While these should not in any way be taken as pricing forecasts, were we to apply current prices of say $70 per barrel of oil, $6.50/MMBTU of gas (an average weighted price of US, European and Asian prices) and $70 per tonne of coal, we can view these volumetric figures of unburnable oil, gas and coal resources into $ terms, this being much easier to comprehend. The 'value' of the unburnable fossil fuels resources would clearly change depending on the region where the asset was stranded and the local price of the commodity at that particular time, but this approach hopefully gives some idea of scale, as shown in Figure 94.

The total value of stranded assets would be equal to just over $100 trillion

Summing the averages for each fuel implies a total value of stranded assets of just over $100 trillion. Clearly this needs to be kept in perspective – the vast majority of these assets have not yet been developed and are not on companies balance sheets, but it is still a vast number, and is more important when considering the growth/capex/returns potential of associated companies, and the impact on the economies, balances of payments etc. of the countries where those assets lie.

Figure 94. 'Value' of Potentially Unburnable Carbon Based on Current Average Market Prices

Scenario	Value of unburnable Oil (US$ trillion)	Value of Unburnable Gas (US$ trillion)	Value of Unburnable Coal (US$ trillion)
With CCS	30	22	57
Without CCS	25	24	62

Note: Assumes $70 per barrel of oil, $6.50/MMBTU of gas and $70 per tonne of coal
Source: Citi Research

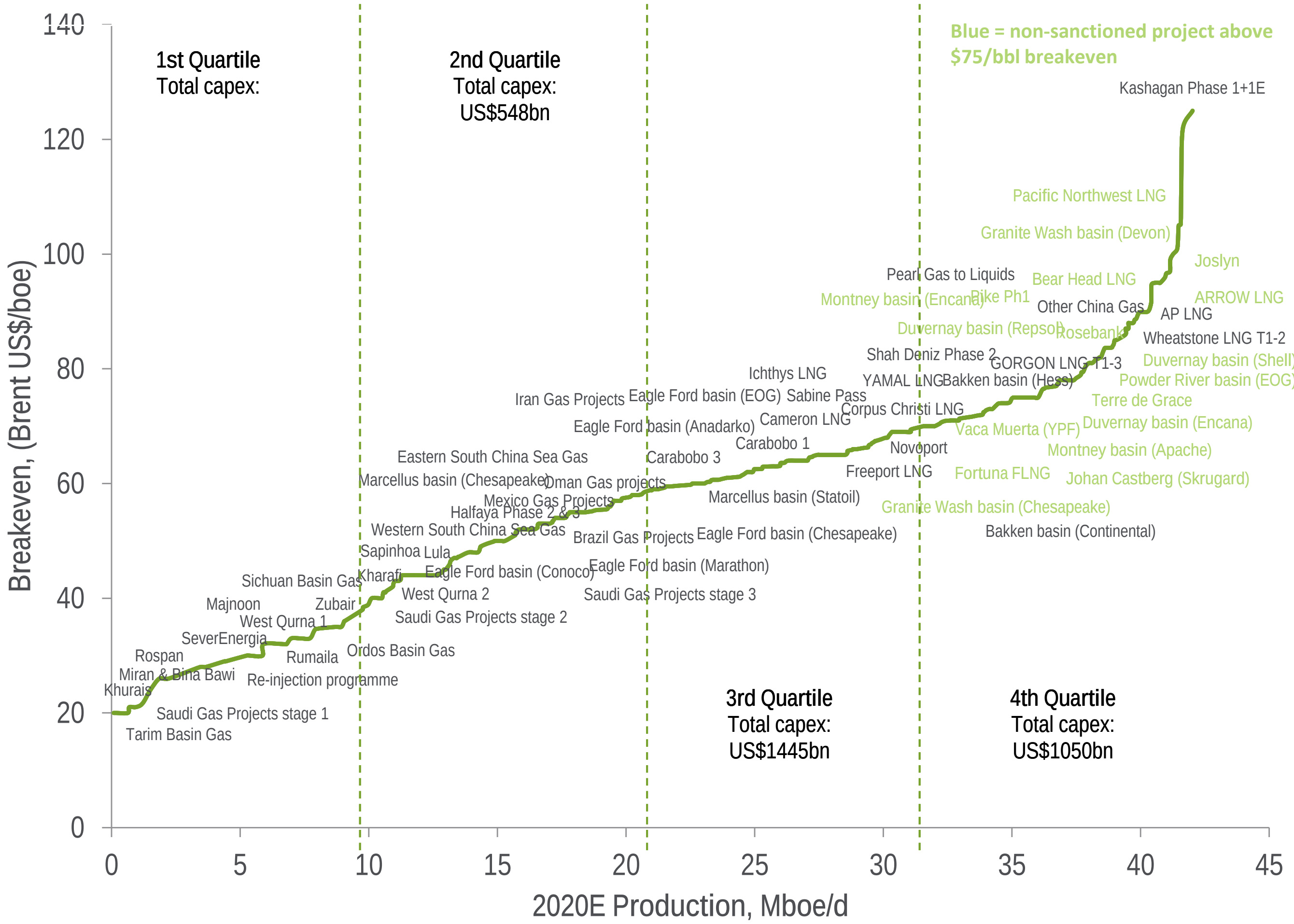
[16] McGlade et al. (2015)

Oil & Gas: Carbon-Stranded, or Economically Stranded?

Due to the current oil price, some assets are already stranded

Citi Research has found that for the first time in a decade, with the decline in oil prices, the supply-curve is beginning to deflate and flatten. The in-depth 325 project analysis (Global Oil Vision) shows that the price environment leaves about 40% of the current investment in oil stranded at prices below $75/bbl on the supply-curve. As companies seek to reposition their portfolio further down the supply curve, sanctioned projects with committed funding will look to embed cost deflation where possible, while stranded non-sanctioned projects without secured funding are likely to be delayed or cancelled to maintain acceptable shareholder returns. Figure 95 highlights the 14 projects in our analysis that remain non-sanctioned above $75/bbl.

Figure 95. Citi's Global Oil Vision Cost Curve for Oil, Showing the 14 Projects that Remain Non-Sanctioned Above $75/bbl



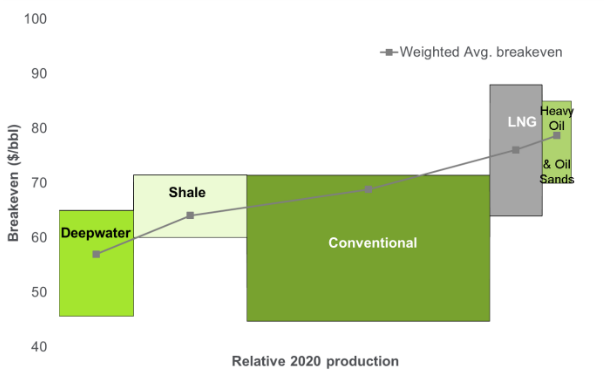
Source: Citi Research, Company Reports

Not All Barrels are Equal

LNG, heavy oil and oil sands are the most at risk

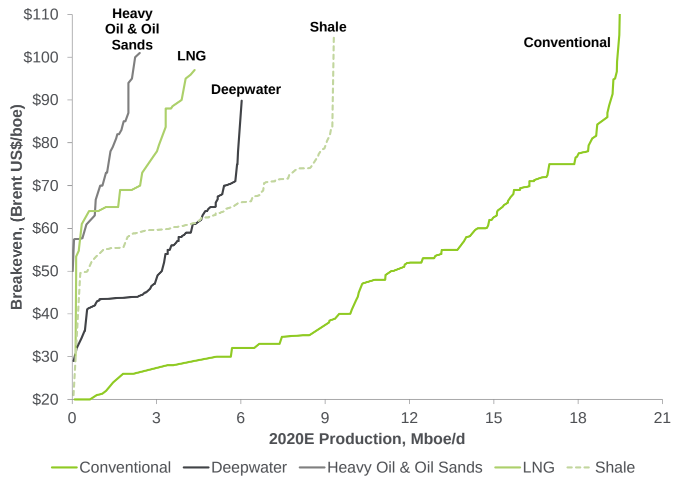
Ongoing sanctioned investments in LNG, heavy oil and oil sands are most at risk of becoming economically stranded high on the cost curve, due in part to the long-dated nature of these developments and their 4-5 year investment lag time before cost deflation of 16-21% starts to improve returns. US shale projects remain the most agile at repositioning themselves on the curve, benefiting from fast cycle times and short payback periods (see Global Oil Services – Investing in a Deflationary World).

Figure 96. LHG, HW and Oil Sands Becoming Stranded While Shale Repositions Down the Curve



Source: Citi Research

Figure 97. Shale Continues to Drive a Wedge in the Supply Cost Curve



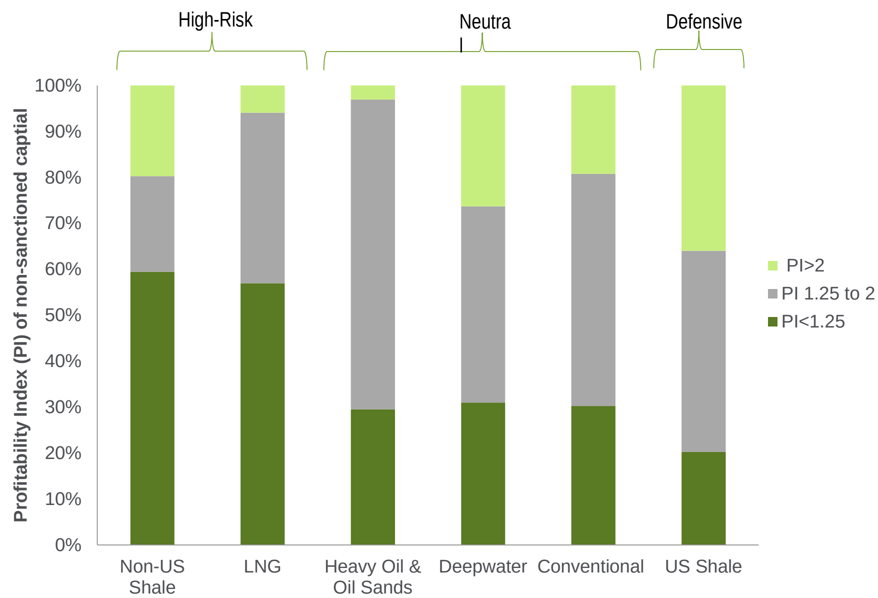
Source: Citi Research

Many of the deepwater tie-backs and hub developments remain attractive in a low oil price environment, improved by the estimated 19% of cost deflation potential expected to be embedded. High capital non-sanctioned deepwater projects are likely to require significant concept development changes or more favorable fiscal regimes to ensure robust economics before sanction; Global Oil Vision shows that 30% of non-sanctioned deepwater is stranded.

Non-Sanctioned Winners and Losers

The decline in oil prices has dramatically altered profitability across all resource types causing companies to announce delays and cancellations to non-sanctioned projects. As the sector begins to reposition investment down the supply-curve, only the most economically robust or strategically important non-sanctioned projects are likely to progress through funding stages in the near to middle term. We would expect companies to mostly progress "Defensive" or top-end "Neutral" projects in their portfolio and look to limit exposure in "High-Risk" projects in resource types like non-US shale and LNG.

Figure 98. Non-Sanctioned LNG and Non-US Shale are "High Risk" with US Shale "Defensive



Note: Defensive = <40% PI<1.25 and >30% PI>2.0, High Risk = >40% PI<1.25 and <30% PI>2.0; Neutral =the rest
Source: Citi Research

The likely consequence will be a shift in weighting of portfolios towards the most economically robust resource types. A decade of cost escalation and the recent decline in oil prices has eroded returns on equity in the sector to a record 29-year low. The reality of the new pricing environment is that it provides a much needed opportunity for the sector to rationalize capital expenditure, embed cost deflation into and reposition portfolios further down the cost curve for future upstream projects.

In conclusion, we expect further cuts in the supply-chain with companies retooling potentially via M&A in the mid-term. While the introduction of government fiscal incentives in the short-term to facilitate production is another clear possibility, this 'unstranding' of economically stranded assets would be at odds with most of the climate goals discussed in this report, and could be argued would not be an efficient deployment of capital. If nothing else, lessons learned from the stranding of assets via the recent fall in the oil price gives food for thought about what the impact of the introduction of carbon pricing (or similar measures from Paris COP21) on higher-cost fossil fuel reserves might be.

Coal: Survival, Extinction, or Both?

The outlook for the coal industry remains challenging; coal is likely to remain an important part of the overall energy mix however cyclically and structurally we think global markets will remain in oversupply capping coal prices and placing significant pressure on the coal mining industry. Its ultimate survival may perversely come down to government intervention, which given the current political backdrop regarding CO_2 emissions doesn't appear likely.

What Has Changed in the Past Two Years?

Seaborne coal prices have decreased when compared to domestic coal prices; and on average around 30% of this industry is losing money

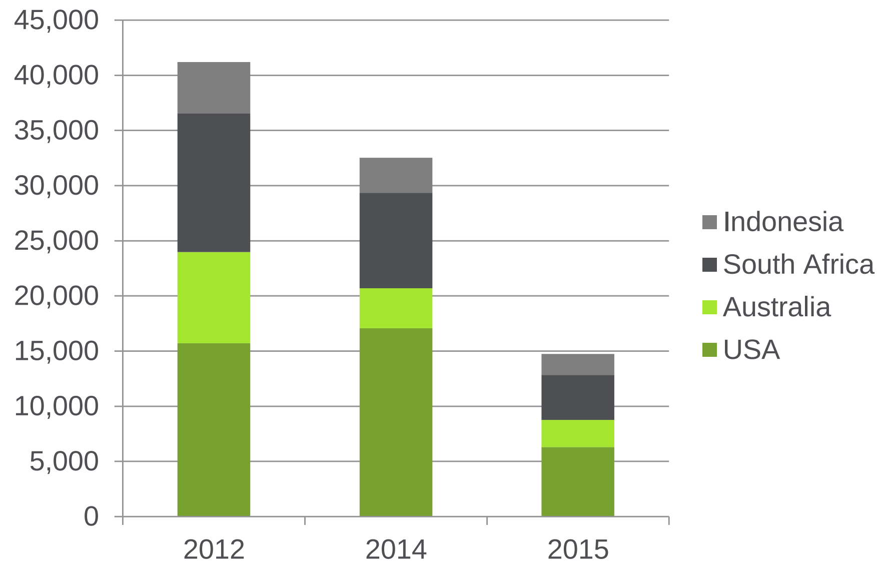
In the original Energy Darwinism report, we expected that coal would be the biggest loser from the shift that was occurring in the energy mix globally. We argued that the biggest impact was likely to be felt in the seaborne market, which is a small percentage of the overall market, as energy importing companies substituted away from imported coal. In the past two years we have seen a dramatic fall in seaborne thermal coal prices, relative to domestic coal prices. On our estimates around 30% of the seaborne coal industry is now losing money on a cash basis.

Figure 99. Seaborne Coal Price CIF Europe and Domestic US US$/

Source: Citi Research, Bloomberg Data

This has placed considerable stress on the coal mining companies; the market value of the listed equities that Citi Research covers has shrunk from around $50 billion in 2012 to around $18 billion today. To date, mine closures, liquidation and bankruptcy have been limited but given our view of the market we think these factors could accelerate.

Figure 100. Market Cap of Listed Coal Companies Under Citi Research Coverage



Source: Citi Research

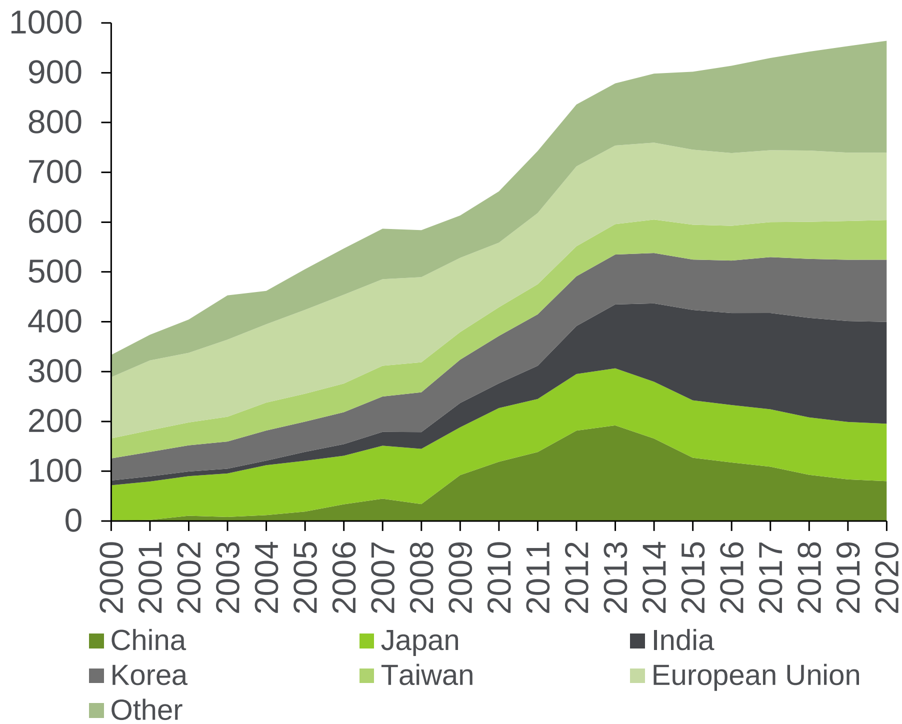
Both investors and governments are beginning to move away from coal

Moreover there has been a shift in investor appetite as regards coal, which has arguably been politically driven. This is best exemplified by the Norwegian government applying a coal screen to its sovereign wealth fund (SWF) investments, a move that is being carefully watched by other investors around the world who increasingly want to make a contribution to addressing climate change (Further Pressure on Coal). The Church of England has endorsed recent comments from the Papacy about reducing greenhouse gas emissions, all of which is leading to continued pressure on the coal industry.

The large coal importing countries have also reacted in the past two years. South Korea is planning to reduce the share of coal in the country's energy mix from 37% this year to 27% by 2029. The government will implement an additional tax rise of around $4.40/tonne across the board, effective July 1, 2015 on the almost 100Mt that it imports, which is around 10% of the seaborne market. In October 2014, China surprised the coal market and introduced an import tariff of 6% for thermal and 3% for coking coal. The China-Australia Free Trade Agreement signed in June 2015 will result in the tax being lowered to 4% from January 1, 2016, to 2% from January 1, 2017 and 0% from January 1, 2018. Coal imported from Indonesia is exempted from import tax due to the China and ASEAN Free Trade Agreement.

We think that India will remain a net importer for some time to come, but to a declining extent over time. Short term, the coal ministry is focused on expediting clearances, bringing in new technology, and improving rail connectivity. This coupled with the auction/allocation of coal blocks provides visibility on India's potential to accelerate coal production. However, the process alone would not enhance coal availability until existing constraints are dealt with. Medium term, we anticipate captive coal production will rise 20% through FY14-20; we now forecast Coal India's volumes to grow at 7% through FY14-20 vs. 2% through FY10-14. A combination of the two should result in India's domestic coal supply growing at ~8% through FY14-20. Our bottom-up demand analysis suggests demand growth of ~7%; imports will follow a declining trajectory over time – with deceleration likely to commence in FY19.

Figure 101. Seaborne Global Thermal Coal Imports by Country – Citi Forecasts (Mt)



Source: Citi Research, Wood Mackenzie

Is Time Running Out for the Coal Industry?

The response of the coal industry so far could be best described as optimistic and hopeful. Optimistic that demand will pick up and prices with it, and hopeful that 'clean coal' technology will become available and save the day. On the demand side we think thermal coal is cyclically and structurally challenged and that current market conditions are likely to persist. This in our view will force the companies to take dramatic actions; the large diversified mining companies such as Rio Tinto, Anglo American and BHP Billiton have either been exiting thermal coal operations or significantly rationalizing their businesses. The pure play or heavily exposed mining companies appear to want to ride out the storm.

Could CCS be a 'game changer' for the coal market?

The 'game changer' and blue sky scenario for coal rests in carbon capture and storage (CCS), though as explained below we think the timeframe for commercial success may be beyond the survival window for a lot of the coal mining companies.

Ironically, the coal industry may need support or bail outs from governments, though the appetite for rescuing the industry both economically and politically appears limited. However, despite the stranded asset issue, coal is likely to remain a backbone in certain regions such as South Africa, where the current power shortages and rolling blackouts suggest that the medium term solution is likely to have to involve coal, the question being how or whether the government will need to incentivize coal production.

Carbon Capture and Storage

Carbon capture and storage (CCS) is often cited as an important technology to allow continued use of fossil fuel resources, particularly coal, in a carbon-constrained world. CCS involves three major steps:

- **Capture:** The separation of CO_2 from other gases produced at large industrial process facilities such as coal and natural gas power plants, oil and gas plants, steel mills and cement plants.
- **Transport:** Once separated, the CO_2 is compressed and transported via pipelines, trucks, ships or other methods to a suitable site for geological storage.
- **Storage:** CO_2 is injected into deep underground rock formations, often at depths of one kilometer or more, where it is permanently stored.

What is CCS?

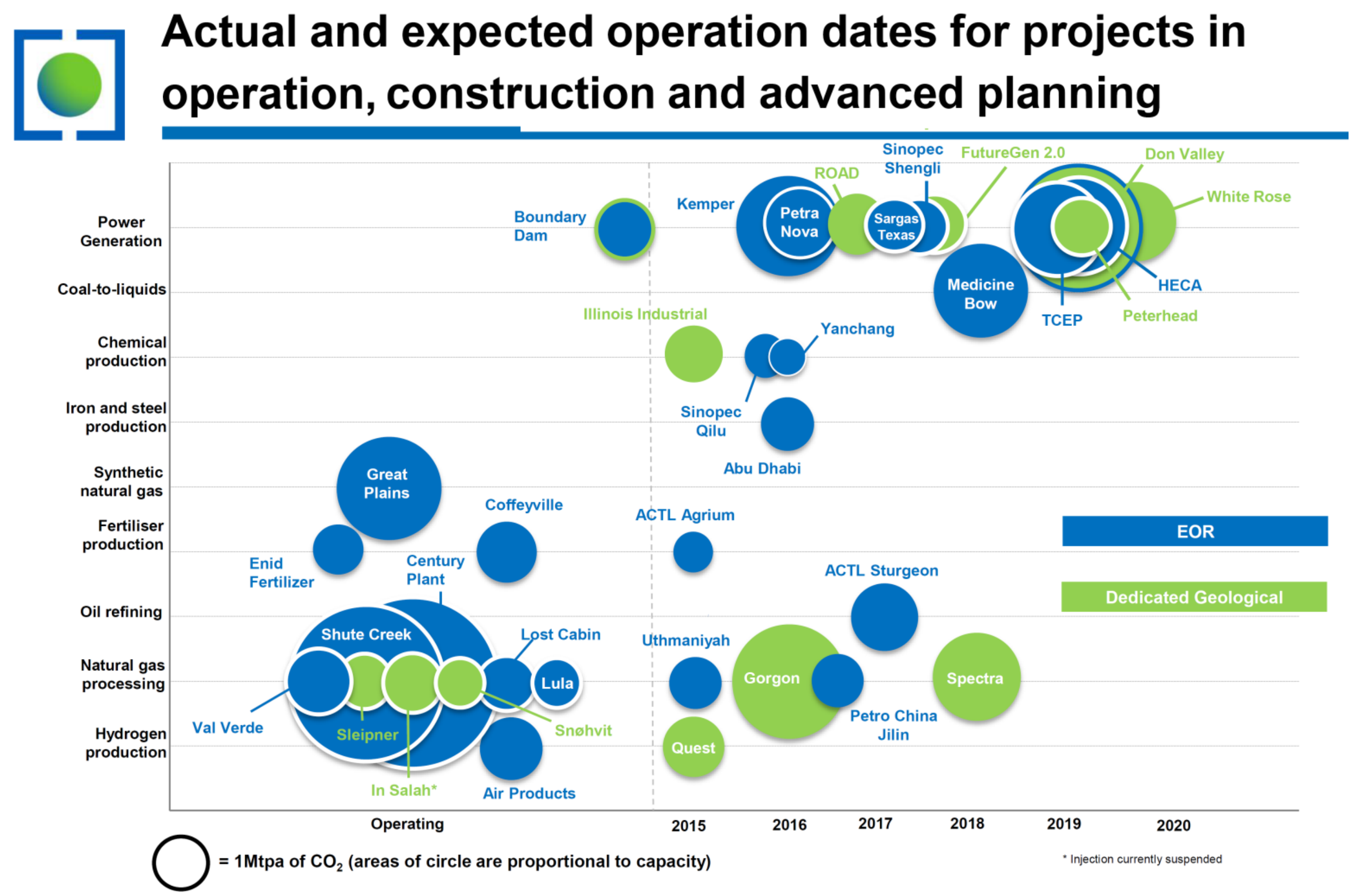
Carbon Capture and Storage (CCS) is a technology that can capture up to 90% of CO_2 emissions produced from the use of fossil fuels in electricity generation and industrial processes, preventing CO_2 from entering the atmosphere. However, it is still at an early stage; according to the Global CCS institute, as of February 2014, there were only 21 active large scale CCS projects in operation or under construction globally, with a combined capture capacity of almost 40 million tonnes of CO_2 per year.

CCS Status

The majority of CCS projects are associated with EOR as it is more cost-effective than geological storage

The Global CCS Institute (GCCSI) has analyzed the status of CCS projects around the world (Figure 102). The majority of projects to date are associated with either enhanced oil recovery (EOR) or with natural gas processing. The recently commissioned Boundary Dam project in Canada has been hailed as a milestone project in the power industry.

Figure 102. Capture Carbon and Storage Projects



Source: Global CCS Institute

Technical Progress, But a Lack of Policy Drivers

CCS is widely seen as being key to achieving the global greenhouse gas emission reductions by 2050 needed to put the world on a path towards limiting warming to 2°C, at lowest cost. This would require substantial deployment by 2030 (i.e. 1.5GT) compared with around 40-50Mt now, rising to ~6GT in 2050. However, if implementation is to accelerate from 2025, project development, including assessment of geological storage sites, needs to accelerate quickly.

However, progress is being made. The Canadian Boundary Dam project (SaskPower) which recently started production, has been hailed as a milestone project. China is progressing the technology, with substantial storage capacity in petroleum basins in the Pearl River and South China Sea areas. In Australia's Surat Basin, Glencore is developing the Carbon Transport and Storage project, currently at a feasibility study stage. As a major coal exporter, Glencore is developing the 120kt per year project to demonstrate to its coal customers that the technology works. The project is able to take advantage of existing Glencore infrastructure in the area (Wandoan mine) to keep costs down.

Carbon prices could provide an incentive for CCS deployment

Despite progress on the technical front, the industry believes there is a need for government policy to support the business case for broad scale implementation. While the fossil fuel industry, particularly coal, has tended to resist carbon pricing developments, ironically the lack of carbon pricing means there has been no business case for large scale CCS deployment.

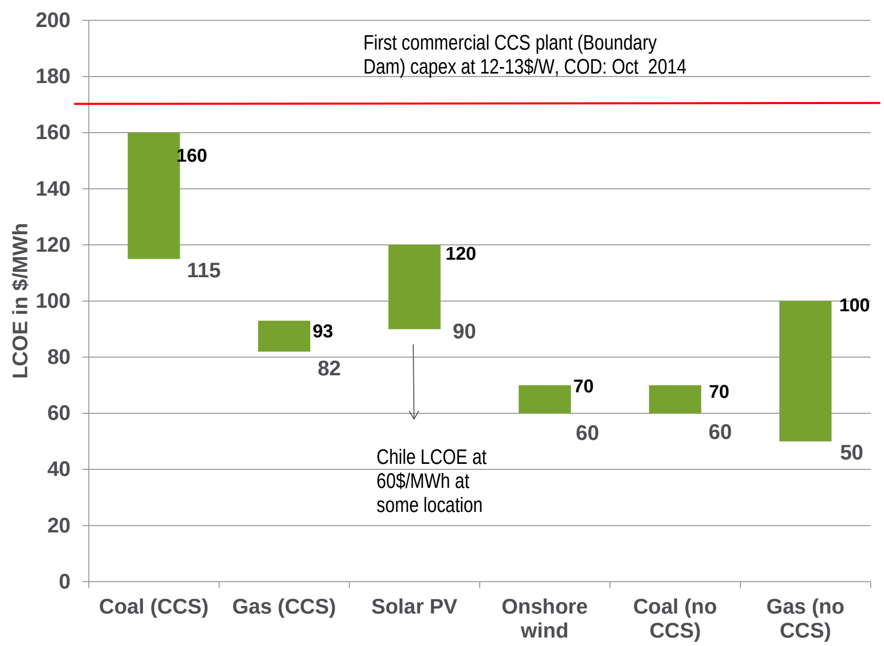
If progress is not made quickly with CCS, it is difficult to see it playing a major role in emissions reductions since other technologies may make sufficient progress to render CCS 'too little, too late'. The concept of "clean coal" may then fail to materialize, further weakening the prospects for thermal coal as a commodity.

CCS Costs

CCS can more than double the LCOE of a coal fired plant

Assessing the cost of CCS is problematic given the limited number of projects and the scale thereof to date. The GCCSI provides some indicative costs as shown in Figure 103, showing that coal with CCS is still significantly more expensive than other technologies. We understand that the CCS estimates shown in the chart are based on US conditions (the Boundary Dam figure is a Citi estimate), and CCS costs will vary with project detail and location. Costs of proving up storage capacity are probably in addition to the costs shown below. However, if the right attention and investment is devoted to R&D and implementation becomes more widespread, there is scope for costs to reduce significantly (as shown by the GCCSI estimates) as has been the case with other technologies.

Figure 103. Comparison of LCOE's for CCS vs. Other Power Generation Technologies



Source: Citi Research, Global CCS Institute

CCS Conclusions

We continue to have reservations about the risk-reward equation for CCS. On the positive side, it represents a potentially enormous game-changer for energy markets; with almost 3000 years-worth of potential coal resources (at current usage rates) if CCS could be commercialized, then in many ways all other bets would be off. If CCS were to materialize on a large scale, it would provide opportunities for companies in the engineering, construction, pipeline and drilling industries, and geological expertise might align with petroleum industry capabilities. Conversely, we harbor reservations regarding the large scale of investment required and long payback periods, which potentially make projects vulnerable if alternative solutions such as renewables, storage or hypothetically algae, become cheaper and more widely adopted in the meantime. Regulatory and political risks obviously remain key factors. We will watch industry progress with interest to see if the needed short-term momentum does in fact increase.

Implications of Paris COP21 for Stranded Assets

While any Paris agreement may well not fully align with the 2°C objective, the outcome is likely to be that countries' commitments to reducing emissions will strengthen over time, with obvious implications for stranded assets in terms of both quantity and timing. Accordingly, while an outcome might not be 'definitely negative', its direction is likely to be clear, and is likely to raise further the risks posed by stranded assets.

How Might Assets Become Stranded?

There are various possible mechanisms by which assets may become stranded, which may affect certain types of assets sooner than others. Some of these effects are already evident in some markets, some may soon become significant, with others emerging in the longer term. We highlight the key possibilities below:

- Regulations could require the closure of certain operating assets, for example old or high emissions power stations.
- Regulatory constraints might add to costs, making assets economically unviable.
- Regulations might be enacted to prevent development or construction of certain new assets.
- Regulation might impose requirements such as emissions constraints, or for example, the adoption of carbon capture and storage, which would increase costs to the extent that potential projects may become unviable.

Hence, market mechanisms such as a price on carbon could make existing or new projects unviable. Demand for fossil fuels could fall as the costs of renewables fall, and technology improves. Local air quality considerations may also play a role in favoring renewables over coal, and regulations may support this.

Markets are connected, so local legislation on CO_2 emissions could affect aggregate global demand for fossil fuels

Given global markets, mechanisms or regulation in one country may of course affect suppliers elsewhere; local regulation in consuming countries will affect aggregated global demand for fossil fuels, with a potential knock on effect on pricing and hence consumption patterns in other markets. These price and weakening demand effects would also depend on (and affect) supply response, because if new projects are abandoned, this may lead to healthier demand and prices for incumbent producers.

Any combination of the above could lead to stranded assets. Certain fossil fuel assets may not be developed, with demand and price forecasts too low (or risk assessments too high) to support project economics as described above. Premature closure of operations could also occur if weaker markets lead to negative operating cashflows.

Types of Stranded Assets

The “stranded assets” concept is already in play; the European power sector has already undergone substantial change in line with the projections of the original Energy Darwinism report. The current focus is on high cost, high emission and long-life undeveloped oil and thermal coal projects, since high-cost long-life projects would be most vulnerable if product demand and prices weakened over time. This includes major new coal provinces such as Australia’s Galilee Basin, which would require major investment in new export infrastructure to be developed. In oil, unconventional deposits such as Canadian oil sands and Arctic projects are under particular scrutiny.

Over time, impacts may spread further to lower cost or lower emissions fossil fuels, including currently producing projects. Gas and LNG may initially be insulated as a lower emissions transition fuel, but fossil fuel constraints could ultimately impact these commodities too, perhaps several decades hence.

Investor Approaches to “Carbon Risk” and Potential Stranded Assets

Many long-term broad-based investors believe that climate change is one of the biggest systemic risks they face, as well as presenting one of the largest opportunities. Tackling climate change is seen as being important to the long term health of the economy and therefore to investment returns.

Investor actions typically start with so-called 'carbon footprinting' whereby an asset manager assesses the exposure of funds to carbon, climate change and associated issues. There is as yet no consensus approach to portfolio footprinting; service providers each have their own methodologies, and increasingly investors are considering what approach they might adopt. Typical approaches include Scope 1 (direct) and Scope 2 (indirect) emissions, per unit of revenue or market capitalization. Other approaches may include some forms of Scope 3 emissions (e.g. emissions from customer use of a company’s fossil fuel products), while others are exploring more novel approaches. A number of major investors have signed up to the 'Montreal Pledge' (launched at the Principles for Responsible Investment conference in Montreal in September 2014), signatories effectively committing to measure and disclose the carbon footprints of their portfolios. In conjunction with footprinting, asset managers have started to adopt a variety of other responses to the issues of carbon, climate change and potentially stranded assets as follows:

Screening, tilting exposure, engagement and hedging are four ways that asset managers have responded to the issues of stranded assets

- **Screening:** Some investors have applied fossil fuel screens to the “riskiest” types of fossil fuel assets – examples include thermal coal production, coal-fired power generation, and oil sands. They may apply a materiality threshold for exclusion from the fund’s universe, while some funds have taken a broader approach to divesting fossil fuel assets.

- **Tilting exposure:** Some investors have adopted or explored ways to “tilt” their portfolios to reduce carbon exposure, based on their own preferred carbon intensity metric, or via the use of “low carbon indices”.

- **Engagement:** Some investors prefer to remain invested and to “engage” with companies to better understand their resilience to a lower carbon world and to better understand capital allocation decisions and what scenarios have been explored, or to encourage companies not to allocate capital to the riskier types of fossil fuel projects. Engagement can also include discussion of executive remuneration incentives, given that incentives based on reserves replacement or production growth might encourage allocation of capital to projects at risk of stranding.

- **Hedging:** Investors may hedge their portfolios against stranded asset risk by allocating funds to low emissions or clean technology investment options.

Norwegian Report on Approach to Coal and Petroleum Investments

Perhaps the best public example of an individual fund’s consideration and response to this issue comes from Norway. The Parliament has announced its intention to adopt a bill which would exclude the $850 billion (the largest of its kind in the world) Norwegian Government Pension Fund Global (GPFG) from investing in companies which themselves, or through entities they control, base 30% or more of their activities on coal, and/or derive 30% of their revenue from coal.

Investor Groups

As well as individual actions, investors have started to form international investor groups, collaborating to encourage policy makers to provide appropriate signals, emissions pledges and plans to encourage the transition to a low carbon economy, then standing ready to allocate capital towards the transition under appropriate policy backdrops. Key investor groups include:

- The UK/Europe Institutional Investors Group on Climate Change (IIGCC)

- The US Investor Network on Climate Risk (INCR)

- The Australia/New Zealand Investor Group on Climate Change (IGCC).

Other international investor collaborations such as that being launched by the Principles for Responsible Investment (PRI), are designed to address potentially inconsistent corporate climate policy positions, where a company's public statements on its support for action to address climate change appear to be at odds with those of industry associations of which it is a member, or think tanks which it co-funds.

Another emerging initiative is the Portfolio Decarbonization Coalition, whose intention is that institutional investors representing large segments of the global economy will disclose their carbon footprints, and publicly commit to ‘decarbonize’ a specific portion of assets under management in a particular timeframe. It believes that that this engagement and reallocation of capital into carbon-efficient investments will provide a strong incentive for companies to adapt their own strategies towards lower-carbon activities.

Potential Implications for Companies

Change in investor attitudes could divert capital away from companies or at least influence their strategies

These changing investor attitudes and initiatives have obvious implications for emissions intensive companies, in that it may divert capital away from those companies, or lead to increasing influence on strategy via a process of greater engagement. The latter approach is perhaps best demonstrated in the recent resolutions proposed by investors for the Annual General Meetings (AGM's) of both Shell and BP. These resolutions (which were supported by both boards and duly passed) were related to greater transparency around the climate and carbon risk issues facing the companies. The aim of such resolutions is to encourage energy companies to develop clear strategies around the risks posed by potential changes to the world's energy markets, and to explain how they reflect these strategies in their investment decisions and allocation of capital.

To what extent increased company disclosures defend the status quo, or contribute to better risk management or an accelerating transition to a carbon constrained world, remains to be seen. However, it is clear that large long-term investors are increasingly seeking to be more active stewards of companies they own, and that energy transition is becoming an increasingly significant stewardship issue.

In a material sign that this engagement is having an effect, on June 1, 2015 a group of major European oil & gas companies, namely Statoil, Total, BP, Shell, ENI and BG, jointly issued a letter calling for governments around the world and the UNFCCC to introduce pricing carbon systems. They stated their hope that these systems would create 'clear, stable, ambitious policy frameworks that could eventually connect national systems' – i.e. a global carbon market.

If the COP21 meeting in Paris is successful, it could lead to significant quantities of stranded assets which could fundamentally alter the outlook for the fossil fuel and power industries. Regardless of the outcome of Paris, investor sentiment is changing and cannot be ignored – after all investors provide the capital to companies, and the removal of this capital (or threat of) could either mean that companies couldn't invest, or could only do so at a higher cost of capital, thereby potentially stranding more projects.

Implications (2): Can We Afford It?

Highlights

- This chapter tries to address three key questions

  – What impact would the higher spend required to follow a lower carbon future have on global GDP?

  – Who pays?

  – What would be the distribution of those effects around the world?

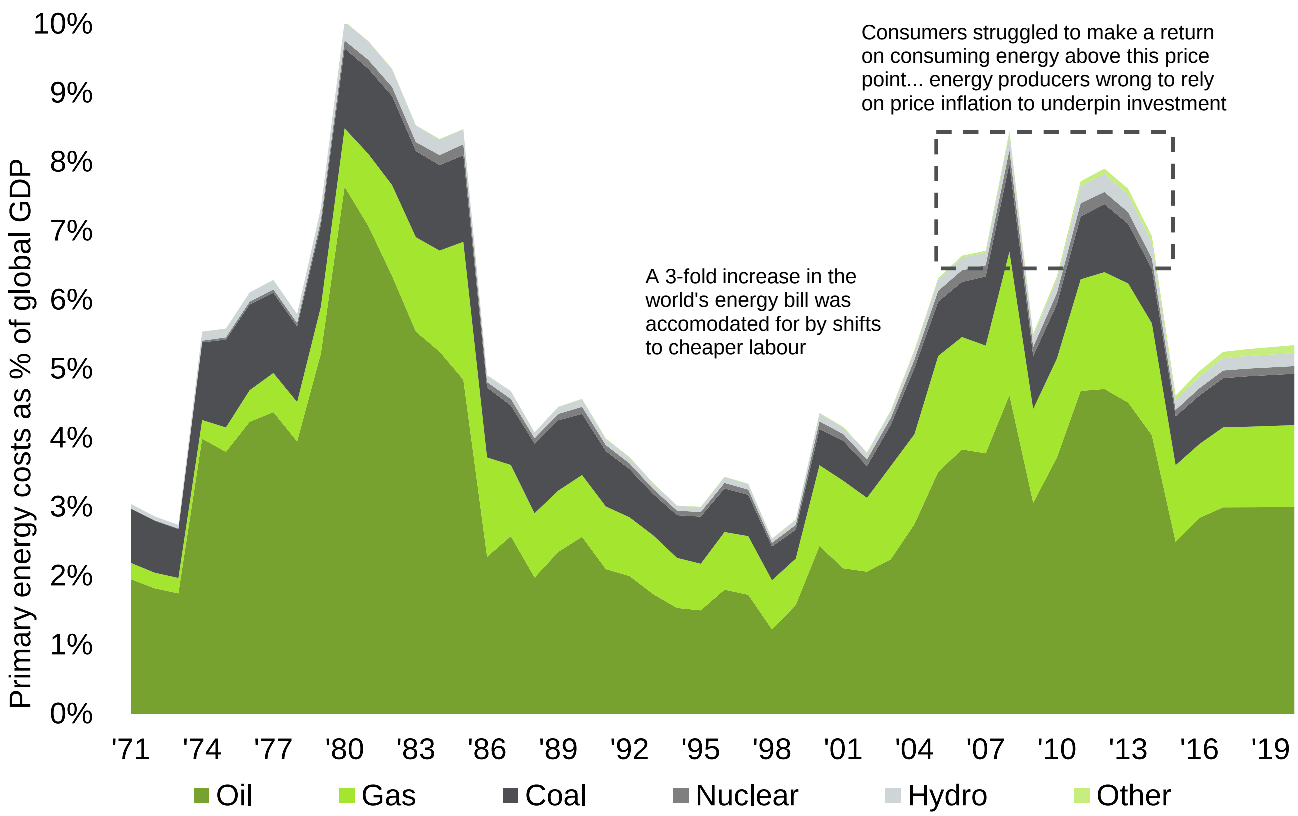
- Energy is inextricably linked to GDP, and restricting it, either directly, or by making it more expensive, represents a negative supply shock. Accordingly we need to consider the impact on GDP of the vast investments required into energy.
- Energy as a cost has historically varied between about 3% and 10% of global GDP in primary energy terms, with the upper levels acting as a brake on global GDP growth
- On our analysis, our Citi 'Action' scenario does not require a material increase in the cost of energy as a percentage of GDP, relative to historic levels – in fact the total costs are lower if we incorporate the fuel savings in later years.
- As discussed earlier, there is a limited difference ($1.8 trillion) in the total bill to 2040 between our 'Action' and 'Inaction' scenarios. However, we demonstrate the higher earlier spend on renewables and energy efficiency in the action scenario, which leads to fuel savings later.
- Comparing the in-year differential cost between 'Action' and 'Inaction 'shows that there is a net cost per annum of following a low carbon path until 2025, after which we move into net savings via lower fuel usage. At its worst, this net cost is only around 0.1% of global GDP; in a cumulative sense there is a net cost out to 2035, beyond which there is a net saving; at its worst this cumulative net cost is still only around 1% of current GDP. In the context of the potential liabilities, these seem like relatively small figures.
- In a positive sense, a more diverse energy mix could make future energy shocks less severe, as could the non-fuel nature of renewables. The greater upfront investment in energy could also help to boost growth and act as a partial offset to the effects of secular stagnation being witnessed currently. Lower long-term energy costs as a percentage of GDP could ultimately serve as a significant boost to GDP, especially compared to the potential lost GDP from inaction.
- The issue of who pays remains a tricky issue – future growth in emissions will come from emerging markets, while historic emissions were largely put in place by developed nations. Given that we are all therefore responsible, and would all suffer the consequences of global warming, it seems logical that everyone should play their part; the issue is of course the split.
- The distribution of effects will depend on national energy intensity, stranded assets, and the importance of energy to a particular economy, in terms of GDP, stranded assets, balances of payments, and employment.

The Impact on Global GDP

Energy costs are inextricably linked to global GDP. Energy is an input into production, alongside capital, labor, technology and other materials. Restricting energy (either directly or by making it more expensive) is therefore a negative supply shock, which will generally make it harder to produce, thereby lowering GDP.

Accordingly it is useful to examine energy costs as a percentage of global GDP in a historic context, to be able to consider the likely future impacts of the higher initial spend on following a lower carbon path.

Figure 104. Energy Costs (Fuels) as a % of Global GDP



Source: Citi Research; BP Statistical Review of Energy

As Figure 104 shows, energy costs in terms of energy supply (rather than capex), have varied widely since 1970, between around 3% and 10% of global GDP. The oil shock of the 1970's is well known, as is the dampening effect that it had on global growth. In more recent years, increases in the cost of energy to 7-8% (a threefold increase in the world's fuel bill) have been offset by the shift to cheaper labor as well as savings made elsewhere.

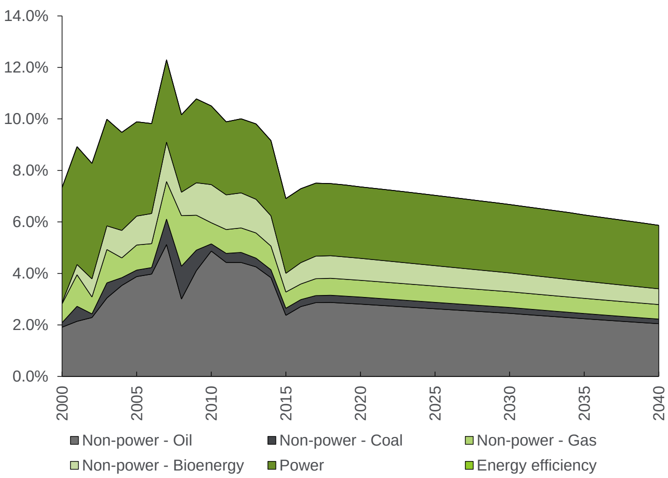
However, this approach only shows one part of the equation. Clearly if we shift towards an energy mix with a greater proportion of renewables such as our Citi 'Action' scenario, fuel costs will be reduced (solar and wind use no 'fuel'), but this relative reduction in fuel usage would be accompanied by a relative increase in the capital spend per MW (the capital cost of renewables is higher than conventional, albeit the LCOE may not be in future). In addition, as we saw earlier, a low carbon future in the Citi 'Action' scenario is likely to entail a significantly higher spend on energy efficiency than our 'Inaction' scenario.

Accordingly, we have adjusted these energy cost figures to incorporate the spend on power generation, using our LCOE approach examined in detail earlier. Since this inherently captures fuel costs where appropriate, we have adjusted the previous primary energy demand figures by removing the portion of demand used in power generation. The resulting spend on power, non-power and energy efficiency can be seen in Figure 105 and Figure 106. Future figures are calculated using current prices for commodities, with learning rates derived earlier continuing for renewables.

A lower carbon future could raise the issue of the tax that governments raise from the use of fossil fuels

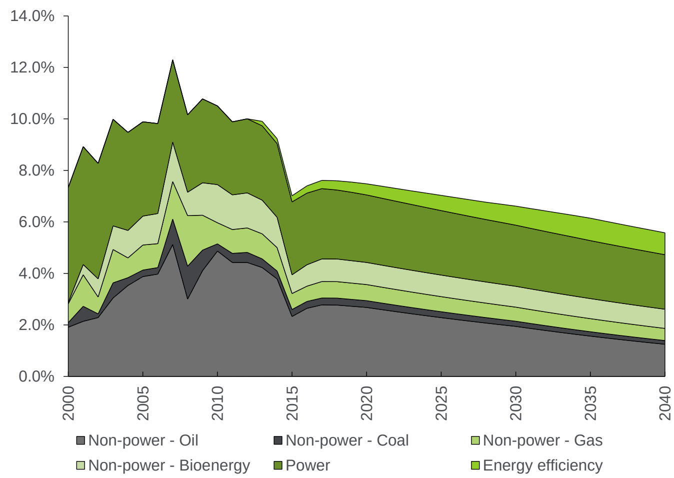
This more holistic approach of capital investment and fuel cost, while not perfect, effectively captures many other effects in the energy complex such as energy transport, upstream margins, refining/conversion and not least taxation. It also raises the issue of the tax that governments take from fossil fuels, on which a lower carbon future will clearly have a material impact. Offsetting that is the level of subsidies currently used in fossil fuels versus renewables, and put as a percentage of global GDP.

Figure 105. Primary Energy (ex-Power) and Power (LCOE) Spend Under Citi's 'Inaction' Scenario



Source: Citi Research

Figure 106. Primary Energy (ex-Power) and Power (LCOE) Spend Under Citi's 'Action' Scenario

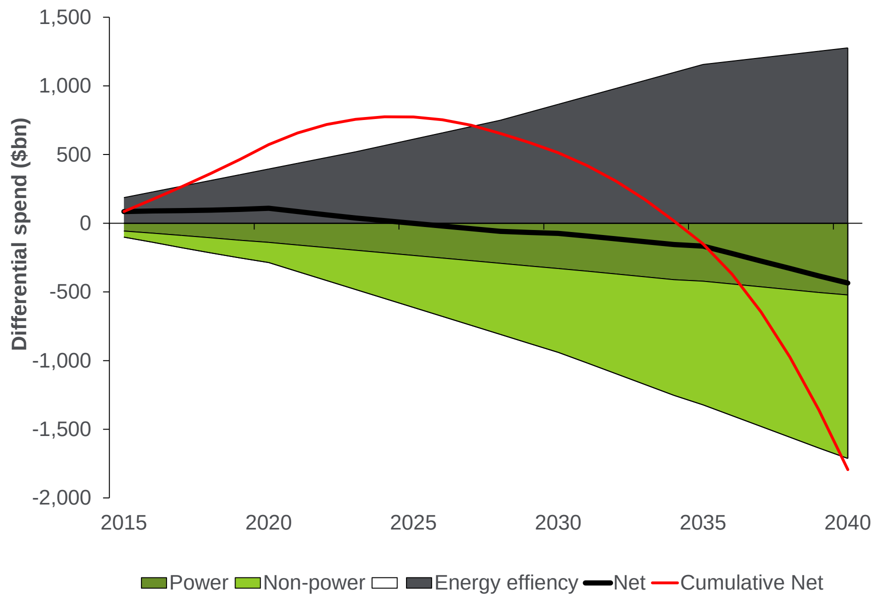


Source: Citi Research

As discussed in the earlier 'Action vs. Inaction' chapter, the totals of investment in both primary energy and power (capex and fuel) are actually remarkably similar from 2015-40 ($190.2trn and $192trn). With a difference of 'only' $1.8 trillion spread across 25 years, it is perhaps unsurprising that the charts look very similar.

Figure 107 helps to highlight the differences in spend. It shows the 'extra' spend on energy efficiency, with the corresponding lower spend on both power and non-power in both capex and fuel terms, with the annual net difference in spend, and the cumulative difference shown by the lines.

Figure 107. Net Differential Spend Between Citi's 'Action' and 'Inaction' Scenarios with Cumulative Total of Spend (Positive) or Saving (Negative)



Source: Citi Research

Of most interest are the 'difference' lines. As the 'net' line shows, in the earlier years we invest more in energy efficiency than the power and fuel savings, before we move to a net 'in-year' overall saving in 2025 and beyond. At this point the cumulative cost/saving line reaches its inflection point at a net cumulative extra spend of $775 billion, before the savings start to reduce this figure. The cumulative cost then becomes a cumulative benefit from 2035 onwards, and would increase significantly thereafter. Clearly discounting would have an effect on the net present value of costs and benefits, a topic that was discussed at length earlier in this report.

Returning to the spend as a percentage of GDP charts, it is also worthy of note that the total spend as a percentage of GDP (admittedly at current prices) remains significantly lower than the peaks seen in the early 2000's and in the 70's, effectively 'freeing up' room to spend the extra in capital costs on renewables and energy efficiency.

The effects of GDP of a lower carbon path are potentially very small – largest annual impact is only 0.1% of global GDP

The likely effects on GDP of following a lower carbon path are, in our opinion, potentially relatively small (though the mix of those effects could vary significantly). The effects on production will depend on the importance of energy to individual economies (in terms of energy intensity, as discussed earlier) and in terms of substitutability. Higher upfront costs will hurt supply in the short-term, while the benefits will be reaped later. However, the hit to growth tends not to be too severe except the cases of very big shocks. The basic rule of thumb is to calculate energy as a share of GDP, and multiply this by the change in 'price' (i.e. if energy is 5% of GDP and energy prices rise by 10%, the cost would be 0.5% of GDP). Accordingly, on the basis of our (undiscounted) figures, the largest annual impact would still only be just over 0.1% of global GDP, with a cumulative effect peaking at around 1% of current GDP. Once again, in the context of the costs to GDP from the impacts of climate change (0.9% to 2.5% of global GDP loss for a temperature increase of 2.5°C), this seems like a very small cost.

Clearly the cost of energy in future won't be as smooth as portrayed in the charts – there will be supply shocks which could potentially push costs up to or beyond that 10% threshold where GDP begins to be materially affected. However, a more diverse energy mix could potentially make those shocks less severe, or more manageable.

As discussed, the extent of any energy 'shock' depends on 1) on the importance of energy in production and 2) one's ability to substitute for it. This highlights several other dynamic elements with potentially positive connotations:

- On average energy use per production has come down. All other things being equal, including one's ability to substitute for energy, this means a shock to energy supply is now less painful than in the past (though for emerging markets with higher energy intensity the shock remains larger, especially for those industrializing currently).
- One's ability to substitute is usually a function of the time horizon. The reason previous spikes in oil prices were so painful (and hit GDP so hard) were that it is so painful to improvise in the short-term – e.g. engines are built for a certain type of fuel. That means that sudden, sharp shocks are very painful in terms of output (and a lack of substitutability in the short-term therefore means that price spikes will be large). Even a major shock that is anticipated should have smaller effects/consequences. Accordingly, the broader energy mix, alongside the lack of fuel elements for renewables could have a positive effect in reducing the impact of future energy shocks (at a global level, though again, national effects will vary).
- The world is currently facing signs of a persistent demand shortage (secular stagnation). Against that, adopting a lower carbon route which actually boosts demand currently (i.e. increased investment) could be an (admittedly small) positive for growth, in that it potentially avoids people being otherwise unemployed.
- Sometimes when you invest, the returns can dramatically exceed what you put in. If, as seems possible, energy savings allow us not only allow to achieve our climate targets, but make energy much, much cheaper in the long run, there might not be 'any' hit to growth, in fact the effect could be positive.

However, to achieve a lower carbon future will require longer term vision on the part of policymakers, and must overcome parochial thinking.

Who Pays?

Paying for climate change has two meanings; paying by restricting one's own emissions, and paying for mitigation elsewhere. Carbon markets, if they can be integrated to a greater extent can help to integrate these two approaches.

The problem of externalities plays a huge part in the discussion of who should pay

The key issue with who pays is that there are externalities; the fact that one country will not alone suffer the consequences, positive or negative, of its climate-affecting actions makes it more difficult to reach socially and globally optimal solutions. Hence international coordination and cooperation is required (but difficult to achieve). More specifically, the issues are as follows:

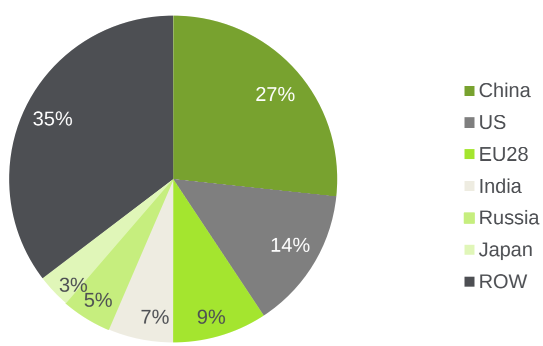
- The majority of future energy demand and emissions growth will come from emerging markets.

- The legacy issue that developed markets now have less energy-intensive economies, and hence restricting their carbon output would be less expensive in terms of GDP impact, combined with the fact that developed markets have historically accounted for the bulk of carbon emissions which have created the climate problem in the first place.

Developed markets do acknowledge the legacy argument, and most appear willing to play their part – the $100 billion climate fund pledge is a good example. However, it is the extent to which they are willing to act, and in particular sensitivity over the relative size of contributions, which are key issues.

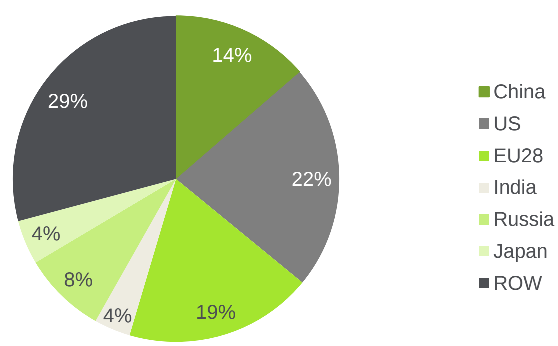
The view that developed markets are doing their part by spending more per MW on new generation capacity in the form of renewables, and that emerging markets will be responsible for the future growth in emissions and hence should pay is in our view too simplistic. It ignores the fact that the existing levels of carbon in the atmosphere were put there by the developed world in becoming 'developed' – i.e. they used the same cheap and dirty power to get richer in previous decades, and hence to adopt a holier than thou attitude to emerging markets is disingenuous. Indeed there is an argument that developed markets are responsible for more than their share of the residual carbon in the atmosphere, given that emerging markets are at least attempting to go for a balanced and less emitting energy complex than developed markets did historically. To which developed markets would probably reply, "But we didn't know at the time, but now you do."

Figure 108. % of Annual CO_2 Emissions by Country



Source: Boden et al. (2013), Houghton et al. (2012), Citi Research

Figure 109. % of Cumulative CO_2 Emissions by Country



Source: Boden et al. (2013), Houghton et al. (2012), Citi Research

Moreover, expecting emerging markets to spend more on power per unit than they simplistically need to could potentially slow their development, which could effectively keep millions of people in technical poverty for longer than is necessary.

Given the joint responsibility for historic and future emissions, it would seem logical that everyone should pay their fair share, especially since we all suffer the consequences of inaction. It would be theoretically possible to create attribution formulae based on cumulative emissions relative to cumulative GDP (potentially on a per capita basis) to enable a fair allocation of costs and an equitable funding mechanism, though once again this falls foul of the argument that emerging markets are manufacturing goods for which developed markets are providing the demand. Mechanisms and political solutions are not however the purpose of this report (instead it being focused on investment). The INDC's to be submitted before COP21 should at least form a starting point for discussions from which some countries can be pushed to act further.

The Distribution of Effects

The key issues regarding the distribution of effects are as follows:

- Emerging markets show significantly higher levels of energy intensity, and are responsible for the vast majority of the growth in energy demand, and hence the impact of the higher cost of energy is likely to impact them disproportionately.
- Whether countries are energy importers or exporters, of which fuels, and how important that energy industry is to their economy will be of key importance to the effects on localized GDP.
- The geographic distribution of energy reserves around the world will affect countries in terms of their 'assets' and future ability to develop and benefit from these reserves (both in terms of fossil fuel reserves, as well as renewables resources such as insolation levels, i.e. how sunny the country is)
- Collectively these will have an effect on local levels of employment.

Making it Happen: Funding a Low Carbon Future

Highlights

- Directing the vast amounts of capital required to transform our energy mix will require innovation on the part of financial markets and the instruments therein.
- While green investment has ballooned in recent years, it is still tiny compared to what will need to be invested, and as a portion of both equity and debt markets. We see the most scope in the credit markets, given that renewable energy and energy efficiency investments lend themselves well to debt financing given their stable cashflows and operating predictability.
- The potential yields generated offer enormous attractions to investors against a backdrop of historically low global interest rates, if politicians, regulators and policy makers can overcome the barriers holding back private capital, outlined below.
- The limited investment to date is not due to a lack of investor appetite; there is an increasingly large investor base with tens of trillions of dollars of assets under management that wishes to gain exposure to 'green' investments.
- With both the need and the desire to invest, the missing link has up to now been lack of availability of investment vehicles of sufficient quality, i.e. investment grade.
- The majority of energy investment will be required in emerging markets, where financial markets are typically smaller, less stable and liquid, and political, FX etc. risks are perceived as higher. Historic finance here has been provided by Development Finance Institutions (DFI's), who are now effectively 'maxed out'.
- The key barrier to attracting sizeable debt investment into energy in emerging markets has been the lack of investment grade vehicles available. If DFI's or other supranational organizations are able to offer some form of credit/risk enhancement to raise emerging market credit to investment grade this could bridge the gap between the need for capital and the desire to gain exposure
- In developed markets the majority of investment will be in energy efficiency which presents its own issues, given the lack of cashflows which can be ring-fenced to cover financing costs.
- Securitization offers enormous potential for both energy and efficiency investment, though banking and insurance regulations such as Solvency II actively discourage entities such as insurance companies from investing in securitized assets.
- We examine new vehicles such as securitized energy efficiency fixed interest instruments, and the emergence of green bonds and yieldco's, all of which offer enormous potential for the future.
- We also highlight the possibilities offered by R&D in terms of the potential it offers to reduce the overall cost of transitioning to a low carbon energy mix.

Introduction

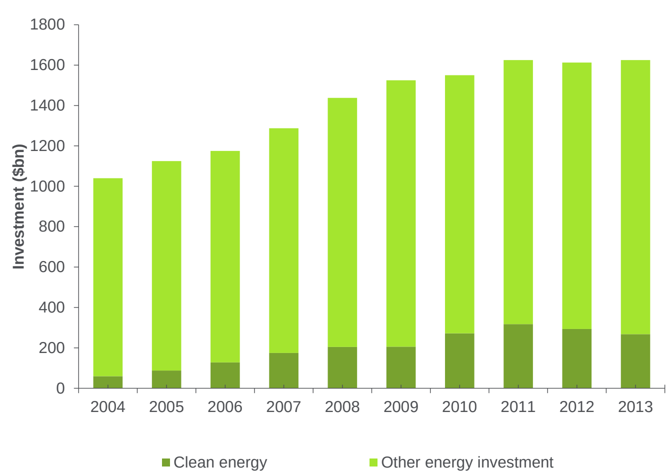
As the previous chapters have highlighted, an enormous amount needs to be invested in energy and efficiency over the coming 25 years, some $50 trillion in capex alone, or close to $200 trillion if we include the cost of fuel. However, as we have also seen, the sums of money required to go down a low carbon path while larger, are in context not that different, especially when we consider the potential costs of inaction. Moreover, the capital element of that investment could actually act as a boost to global growth (or at least not too much of a brake). However, that investment will be in different locations and different industries than might otherwise have been the case. Accordingly it is not just global political will that has to come together to tackle the issue of potential climate change; to redirect investment of that magnitude into new areas will require innovation in both financial markets and the instruments therein.

Historic Investment Levels

In 2014, investment in renewable energy surpassed that of conventional power generation, totally around $250 billion per annum

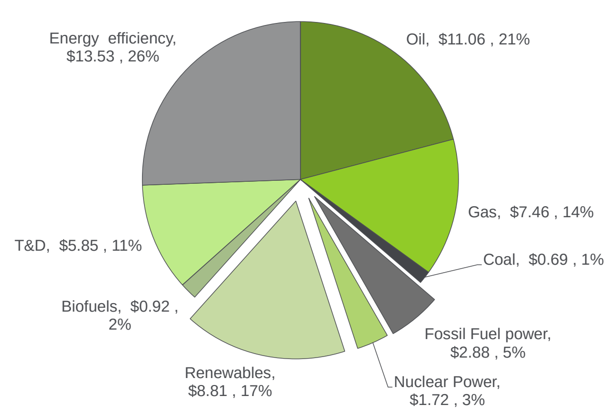
While the world of green investment has ballooned over the last 10 years, it is still a drop in the ocean compared to total energy investment, and to the amounts required to adopt a low carbon future. Nevertheless it is worth noting that in 2014 we expect investment in renewable energy actually to have surpassed that of conventional power generation; in capacity terms it was almost equal in 2013 - a milestone that few would have thought possible a few years ago, and one that offers faith in our ability to change our investment behavior relatively rapidly.

Figure 110. Investment in Clean Energy in the Context of Total Primary Energy Investment



Source: Citi Research, Bloomberg New Energy Finance, IEA

Figure 111. Cumulative Investment 2014-35 by Type Under the IEA's '450 Scenario'



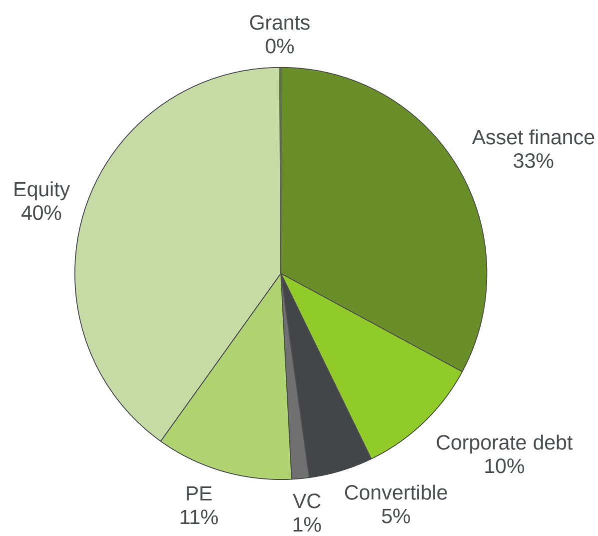
Source: IEA (2014)

Figure 110 shows investment in clean energy has been around $250 billion per year in recent years, rising further to $310 billion in 2014, but is still dwarfed by the total investment in primary energy (a total of around $1.6 trillion per year). Onto this figure we should really add the estimated current expenditure in energy efficiency of $160 billion per year to gain a full picture of 'cleantech' and energy spend. Thus renewables represents around 17% of current total investment in primary energy (as opposed to just power).

However, as Figure 111 shows, the cumulative investment figures out to 2035 under the IEA's '450 scenario' are enormous. Energy efficiency and renewables are estimated by the IEA to require capital investment of $13.5 trillion and $8.8 trillion over the next two decades. Interestingly renewables stays at around 17% of that total investment, with an annual spend which is actually only at 2014 levels, and hence markets are already arguably providing enough capital to the renewables industry (in quantum at least, if not necessarily in the markets where it will be needed). The biggest change is the enormous increase in investment in energy efficiency which rises from current levels of around $150 billion per year (depending on definitions) to over $500 million per year, being largely responsible for the increase in annual spend on energy and efficiency to around $2.5 billion per annum from 2030 onwards.

So far the bulk of the investment into clean energy has been equity and project finance, a situation that continued in 2014, as shown in Figure 112.

Figure 112. Announced Investments Into Clean Energy and Efficiency by Financial Vehicle, 2014



Source: Citi Research, Bloomberg New Energy Finance

As the pie chart shows, equity in its various forms still provided around 50% of finance flows into the space in 2014, with the majority of the remainder being covered by asset finance, with bonds and convertibles making up just 15%.

If we take this equity investment in the context of the global equity market capitalization of $70 trillion, it pales in significance. Even more extreme is to compare the fixed income part of annual investment (effectively around $100 billion) against global credit market values of $166 trillion, equivalent to just 0.06%.

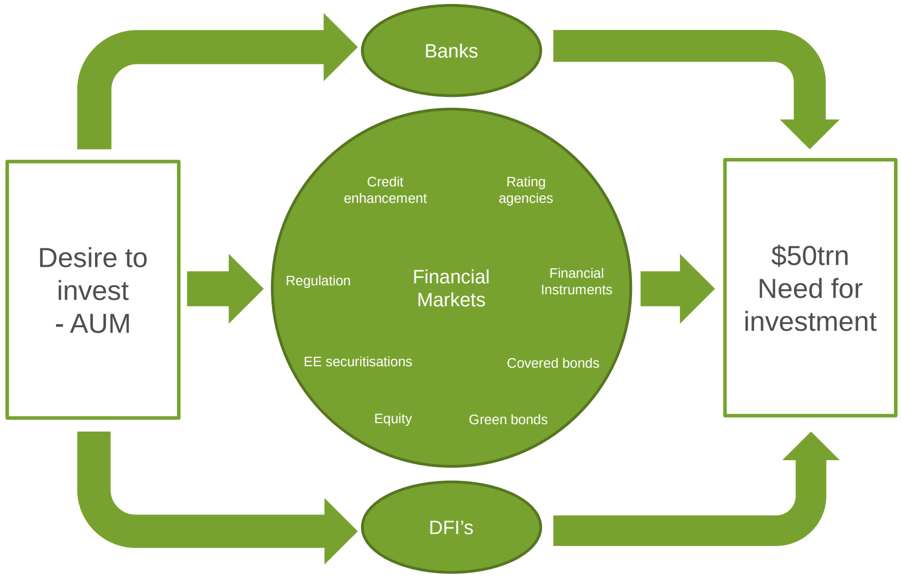
It is therefore only a very small part of the overall investment market which is in any way directly exposed to the low carbon theme. Given the topic's significance and broader implications for markets in terms of its potential impacts on global GDP, health, population displacement, agriculture/food, sea levels, not forgetting the enormous cost of transitioning to a lower carbon energy model, that seems a remarkably small percentage.

Institutional investors are investing more in clean energy fuels

Yet this lack of exposure is not due to a lack of appetite; The IIGCC (Institutional Investors Group on Climate Change) has more than 100 members representing $12 trillion in assets under management; The Carbon Disclosure Project works with institutional investors with $95 trillion of asset under management (AUM); The Climate Bonds Initiative works with institutions with $34 trillion AUM. As discussed earlier, the Norwegian Government Pension Fund (the world's largest sovereign wealth fund) has announced that it will no longer invest in companies that are overly exposed to coal, and numerous other institutions have undertaken similar approaches to make their portfolios more environmentally friendly.

So, if the investment is needed, there are project developers seeking capital, and the appetite and interest in gaining exposure (or limiting exposure to carbon intensive investment) is there from a very large part of the institutional investor base, why isn't the investment already happening? The simple answer is the limited quantity and quality of the investment vehicles available.

Figure 113. While DFI's and Banks have Historically Provided Much of Financing, Capital Markets Must Now Innovate to Facilitate Investment



Source: Citi Research

Therefore, this investment needs to be facilitated via the creation or adaptation of new financial instruments, and developing sizeable, established, liquid and stable markets for these products.

The debt market has the largest potential

While equity markets have mobilized themselves, it is the debt market where perhaps the greatest potential lies. Renewable energy projects lend themselves very well to debt capital markets; they have very little operating variability, and have long term stable cashflows which can therefore take relatively high levels of leverage (in some cases up to 80%) thereby minimizing the cost of capital and keeping investment costs as low as possible for a given return. The key risk on many of these projects is regulatory/political rather than operational – if this investment program is to happen, it must be against a stable regulatory backdrop with, most importantly, an end to the retrospective regulation that has been seen recently in various areas around the world. This perceived risk ultimately pushes up costs and discourages investment, the opposite result to that which is desired.

The returns offered by these projects and their long term nature should offer significant attractions against the backdrop of historically low global interest rates, and a worldwide search for yield. As discussed, the longer term (20 year) nature of many of these projects would allow pools of investors such as pension funds, insurance companies etc. to match long-term liabilities with long-lived assets.

The challenges of allowing the investment to flow are very different for clean energy investment versus those for energy efficiency; we examine these in turn below.

Financing Renewable Energy Investment

While developed markets need to invest in energy efficiency rather than new capacity, growth in energy demand is coming from emerging markets meaning that it is here that the bulk of asset finance will be required. The equity and certainly debt markets in these regions are unlikely to be large, stable and liquid, and hence potentially unsuited to financing these investments, or at least not with a low cost of capital. This creates another financial hurdle, especially when these projects must compete in LCOE terms with often sizeable subsidies on fossil fuels. In emerging markets, much of the financing therefore currently comes from banks, on whom current pressure to reduce the scale and risk of their balance sheets creates another headwind.

Most investment in these sectors in emerging markets has hitherto been funded by DFI's. However, these institutions now largely find themselves at capacity, a situation exacerbated by regulatory constraints placing pressure on banks to reduce leverage or raise the quality of their debt portfolios.

While private capital has been actively engaged in investment in renewables and infrastructure generally in OECD markets, there has as yet been little involvement in the typically sub-BBB emerging markets, due to the inherent macro-economic, political, foreign exchange, refinancing, governance and regulatory risk. Yet with DFI's effectively 'maxed-out', and in the absence of an injection of fresh capital, private capital must be enticed into these emerging markets to co-invest alongside the DFI's.

The search for yield against a backdrop of historically low global interest rates offers enormous potential, if politicians, regulators and policy makers can overcome the barriers holding back private capital from investing in this sizeable opportunity.

In our opinion, the credit rating issue is one of the most significant issues to be addressed; if DFI's or other supranational organizations are able offer some form of credit/risk enhancement to raise emerging market credit to investment grade this could bridge the gap between the need for capital and the desire to gain exposure, and address the enormous emerging market infrastructure deficit which exists, and not just in the world of energy. Indeed, vehicles such as the $100 billion green investment fund might ultimately facilitate much greater levels of investment if used for credit enhancement rather than by investing directly.

Clearly securitization offers enormous potential in these markets. However, even if DFI's can successfully bridge the gap to investment grade, banking and insurance regulations such as Solvency II actively discourage entities such as insurance companies from investing in securitized assets.

Projects certified under the CDM saved 2.9 billion tonnes of CO_2 equivalent between 2008 and 2012

If these emerging markets can be opened successfully, then mechanisms such as the Clean Development Mechanism (CDM) or Joint implementation (JI) discussed earlier could be refined to further facilitate cross-investment between countries. The main issue with carbon markets and hence these mechanisms, is grandfathering and abuse via local over-issuance of permits which force a (potentially unfair) flow of capital from one country to another. The UNFCCC estimates that projects certified under the CDM saved 2.9 billion tonnes of CO_2 equivalent between 2008 and 2012 – in the context of annual emissions of 40GT this is relatively small, but with the right political will, it could become a much larger driver.

An example of these innovative new financing mechanisms is the World Bank's Pilot Auction Facility (PAF) for methane and climate mitigation. This is a 'pay for performance' mechanism, which uses auctions to allocate funds into projects in emerging markets that reduce methane emissions. Bondholders in a project will be issued with emissions reductions certificates, tradable via the CDM, once emissions have been verified (hence the 'pay for performance'). What is innovative is that the PAF entails a put option at a pre-agreed strike price, effectively guaranteeing a minimum price for the CER's. If carbon prices fall, the bond holder is protected, but if carbon prices are stable/rise, the bondholder keeps the benefit. The PAF effectively facilitates lower-risk investment into EM methane reduction projects, at no upfront cost to the World Bank (unless carbon prices fall, in which case it would be liable for the different between the strike price and the market carbon price).

Financing Energy Efficiency Investment

In developed markets the 'extra' investment of following a low carbon path is forecast to be mainly in energy efficiency, which presents its own difficulties. Energy efficiency investment is unintuitive; while normally one invests in an asset which generates cash returns, in the case of efficiency the return usually comes via future avoided costs (i.e. lower energy bills/usage). It's effectively the same thing, but it makes financing it harder as the investment is unsecured, and doesn't explicitly generate a cashflow which can be ring-fenced to cover for example interest payments on the investment cost. Energy efficiency creates greater net cashflows to an entity, an element of which therefore have to be earmarked to cover the interest on investment. This lack of ring-fencing is a significant hurdle. In addition, if energy prices fall via reduced demand (from greater efficiency), the 'return' on energy efficiency investment falls as the relative benefit is squeezed.

Given the difficulty in financing energy efficiency, the majority of investment to date has been funded from corporate or personal/household cash reserves, but the right financing mechanisms could once again accelerate and grow investment.

The key issues in energy efficiency investment are size, standardization, accreditation, and the lack of pipeline generated from existing public subsidies which are limited both geographically and in scale.

Given that much of the necessary investment in energy efficiency will be undertaken by households, the individual project size will be very small (typically $7.5-$10K per household project in the US) across a fragmented range of property types. This will therefore require different forms of finance, and pooled or securitized investments are likely to be necessary. Innovative financing solutions in solar in the US where panels are installed on household roofs, but paid for by a third party, the return being shared, shows how goals can be achieved at a residential level without expecting the householder to put up the full capital investment. Other examples are PACE (Property Assessed Clean Energy) loans which can again be securitized. Avenues such as On Bill Repayment (OBR) offer forms of enhancing credit quality via the use of another entity's revenue collection mechanism.

WHEEL aims to create a national financing platform that can help home owners make necessary improvements such as insulation

Citi and Renew Financial recently announced the first ever asset-backed security (ABS) transaction comprising unsecured consumer energy efficiency loans, the first securitization from the WareHouse for Energy Efficiency Loans (WHEEL). Announced in 2014, WHEEL is an innovative public-private partnership between national leaders in finance and energy in the US, including Citi, Renew Financial, Pennsylvania Treasury, the National Association of State Energy Officials, Energy Programs Consortium and a growing number of states and utilities. Its aim is to create a national financing platform to bring low-cost, large-scale capital to government and utility-sponsored residential energy efficiency loan programs. Through the recent ABS program, homeowners can borrow up to $20,000 at very competitive rates to make a range of improvements to their homes, such as HVAC equipment, water heaters, roofing, insulation, windows and energy efficient appliances. While a relatively small pilot scheme at the moment in 3 states (Pennsylvania, Kentucky and the Greater Cincinnati Energy Alliance have all joined WHEEL), numerous additional states are expected to join soon, and the model should be highly scalable. These mechanisms are not grants, but rather a 'socialized credit enhancement facility', which provides cheaper capital for energy efficiency projects to those who might otherwise be unable to gain access.

Perhaps greater potential for debt capital markets comes via spending on public buildings in terms of energy efficiency. Given very high levels of real estate ownership of building stock by local councils and authorities, the scope for sizeable investment volumes funded by municipal borrowing ('green munis') is significant. Several examples of this already exist, for example the Delaware Sustainable Energy Utility, where an energy efficiency revenue bond of $67.4 million resulted in net cashflow savings for government agencies in the state equal to 30% of aggregate project cost.

Even if states are unable to issue green bonds themselves, there is still scope to achieve energy efficiency investment and savings; Detroit recently replaced all of its street lighting with energy efficient lighting, achieving significant savings on its energy bills in the process. The notable fact here was that this was facilitated via a loan from Citi to Detroit which was then refinanced, effectively creating an investment grade vehicle from a municipality with a fairly low rating. ‘Green investment’ is also likely to be well received by voters generally; given that it achieves financial and energy savings as well, the attractions are likely to be significant, demonstrating the potential scalability of municipal green bonds.

The above represent examples of projects in which Citi has been involved, as part of its goal to lend, invest and facilitate $100 billion within 10 years to finance activities that reduce the impact of climate change. This new target, announced in 2014, follows Citi's previous commitment to facilitate investment of $50 billion over 10 years, which was completed 3 years ahead of schedule in 2014.

A large part of energy efficiency savings will also be in the transport sector, and here again much of the investment will be taken by corporates who could effective issue green bonds (we have now seen the issue of green corporate bonds by several large multinationals such as Toyota) to finance these investments. Grants could also have an effect here, as has been seen with grants to purchasers of some electric vehicles, thereby offsetting the increased capital cost.

Storage while not technically reducing overall consumption, offers the potential for more efficient power markets, smoothed demand profiles and less stranded generation assets. As such it can potentially reduce the overall cost of an electricity market, thereby freeing up capital for investment elsewhere. Residential storage in combination with home energy management systems (such as Hive and Nest) also offers reduced consumption and cost. (See Battery Storage: The next solar boom?)

Regulatory Considerations

Efficiency standards could also make a difference to the overall energy usage

It is not just financial markets that have their part to play. From a regulatory perspective, greater application of efficiency standards, knowledge, and accreditation will also facilitate greater investment in energy efficiency. Efficiency standards and understanding/marketing thereof on electrical appliances, cars and buildings will also help to reduce overall energy usage.

One thing we have learnt from regulation is that it needs to be regularly updated and flexible enough to adapt to externalities such as lower economic activity, the main reason that an effective over-issuance of permits relative to lower economic activity has left carbon prices so low in the EU ETS. The same was true of solar regulation in Germany; a lack of flexibility in granting high legacy feed-in tariffs to solar farms despite a massive fall in the price of solar panels led to super-normal returns and an unjustifiable subsidy bill which inevitably led to a boom and bust cycle. Conversely what must be sacrosanct is that regulation must not be retrospective, as witnessed in several countries, most notably Spain. This raises future costs of capital for everyone (and not just in that region) and deters future investment.

Ending fossil fuel subsidies and diverting those funds into cleaner energy could have an effect on the mix of energy sources at a limited cost

A particularly tricky area will be an end to end to fossil fuel subsidies (and potentially renewable subsidies). Subsidies are incredibly negative for both energy efficiency and renewables in that they make the relative merits of undertaking a project much less compelling. The justification for subsidies is that energy is necessary to boost growth and in developing markets energy needs therefore to be available and affordable. However, diverting those subsidies into different forms of energy (cleaner energy, e.g. gas vs. coal, or renewables, or indeed energy efficiency) could have a transformational effect on the energy complex at relatively limited cost. The IEA estimated that fossil fuel subsidies in 2013 amounted to $548 billion. Admittedly the implied subsidy will fall significantly this year, potentially to we estimate $300-350 billion given the recent fall in the oil price, but in the context of total primary energy spend of $1.6 trillion per year, this is still a very large figure. Add to this the estimated $121 billion of global renewable subsidies in 2013 (IEA), and the extent to which the world is already manipulating energy markets becomes clear; the challenge therefore is simply to adjust them in a different direction.

Figure 114. Fossil Fuel and Renewable Energy Subsidies as a Percentage of Total Global Energy Spend

Source: Citi Research, IEA

Financial Instruments

We examine below some of the key instruments available which could be developed further to facilitate low carbon investment:

- Green bonds
- Yieldco's
- Covered bonds
- Securitization

Green Bonds

Recent years have seen the emergence of the so-called 'green bond'.

Green Bonds are a fixed income instrument, the proceeds of which will be used exclusively to finance 'Green Projects', defined as any activity or project which promotes progress on environmentally sustainable activities, and is in accordance with the recently launched 'green bond principles' outlined below:

1. **Use of Proceeds**: The finance raised by the green bond must be used for environmentally friendly and sustainable projects such as renewable energy, energy efficiency, sustainable waste management, sustainable land use, biodiversity conservation, clean transportation, sustainable water management, and climate change adaptation.

2. **Project Evaluation and Selection**: The green bond issuer must outline the decision making process it intends to adopt in determining the eligibility of projects to receive proceeds, in terms of which specific category of project, the criteria which makes the project eligible, and the environmental sustainability objectives.

3. **Management of Proceeds**: The proceeds should be credited to a sub account and tracked as they are invested with a high level of transparency. The use of an auditor or other third party to verify allocation of funds and tracking is encouraged.

4. **Reporting**: Issuers should report at least annually on the use of proceeds, in terms of which projects have been financed. The principles also recommend the use and disclosure of qualitative and quantitative performance indicators of the expected environmental sustainability impact of the investments

Types of Green Bonds

There are four main types of Green Bonds: The most popular and mainstream is a regular fixed income bond which has a full guarantee by the Issuer, however the "use of proceeds" of the bond can only be used for "climate friendly" projects, as mentioned above.

- **Green Use of Proceeds Bond**: the most common type, a normal fixed income bond with recourse to the issuer, the proceeds of which must be used for environmentally friendly/sustainable projects.

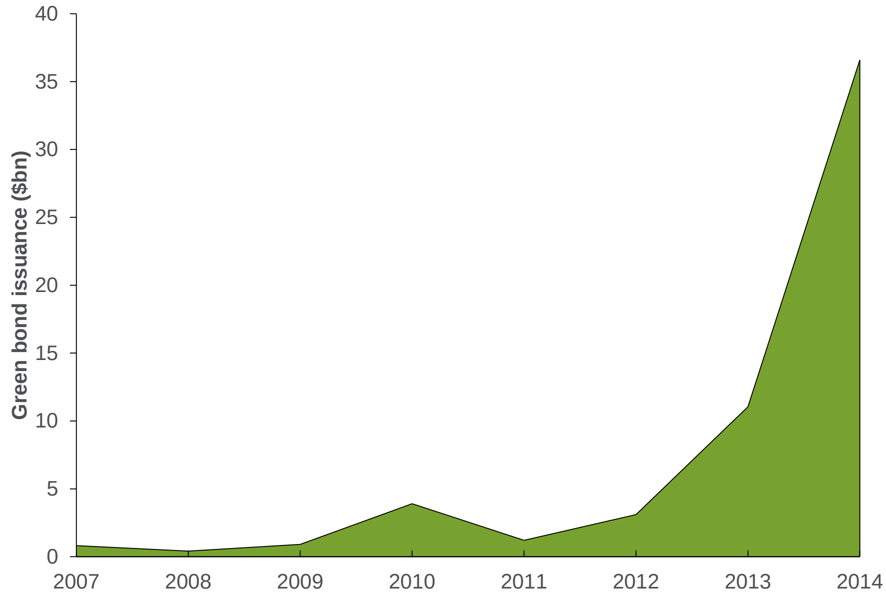
- **Green Use of Proceeds Revenue Bond**: (non-recourse to issuer, linked instead to income streams).

- **Green Project Bond**: Linked to a single/multiple qualifying green project, with no recourse to the issuer.

- **Green Securitized Bond**: A bond with collateral and cashflows provided by multiple projects.

The majority of green bonds issued to date have been via supranational organizations such as the World Bank and International Finance Center (IFC), though the last couple of years have seen corporate green bonds emerge such as those from Unilever and Toyota. Figure 115 highlights the rapid growth that has been seen in the green bond market.

Figure 115. Historic Green Bond Issuance



Source: Climate Bonds Initiative

In 2014 green bonds issuance totaled $37 trillion

As Figure 115 shows, green bond issuance rocketed in 2014 to nearly $37 billion, and expectations for 2015 vary from $50 billion to $100 billion, showing further rapid growth. Cumulative green bond issuance currently stands at $59 billion via some 300 bonds from 19 countries in 23 currencies.

The markets for green bonds are still evolving, but the emergence of accrediting organizations and industry guidelines/best practices such as the green bond principles is helping to develop the market.

Yieldco's

Recent years have seen the birth of the yieldco in both the US and more recently Europe. A yieldco is essentially an investment vehicle which invests in multiple projects, thereby once again reducing risk vs. single asset project finance via the portfolio effect. These projects are typically levered at anything up to 80%, with the long term stable cashflows being well-suited to cover interest payments on the debt and to provide dividends to equity investors. Dividends paid are typically 90% of cash available for distribution (CAFD), thereby providing a dividend buffer to cover limited volatility in cashflows, as well as providing cash to invest in new projects which are typically dropped down from a sponsor/parent via a right of first offer (ROFO) agreement. As well as providing spread-risk equity investments, yieldco's can raise debt at a parent rather than project level thereby once again reducing single asset risk.

Investors tend to view these vehicles on a total return basis, i.e. dividend yield plus CAGR of dividends, with a currently tight valuation correlation. However, it is notable that companies in areas where regulatory risk is perceived to be higher (particularly where there is a history of retrospective regulation), yields need to be higher to offset this perceived risk. This starkly demonstrates the impact of a lack of regulatory stability or trust on the implied cost of capital, with knock on effects on the relative costs of different energy forms and the ability of nations therefore to transform their mix.

Covered Bonds

One of the most promising 'new' instruments with the potential to fund green investment is the covered bond. A covered bond essentially has the advantage of not just being asset backed, but also benefitting from a guarantee from the issuer or another body such as a government or supra-national organization. This concept of dual recourse thereby reduces risk and leads to potentially higher credit ratings.

Covered bonds have been in existence for around 250 years, often being used in the real estate market, as well as in areas such as public housing. The similarities with green investment which also provides a 'social good' are obvious and could be used as a justification for guarantees from governments or other organizations.

Against a backdrop of banks trying to reduce leverage ratios these assets have the potential to be treated as high quality assets, thereby potentially allowing investment by banks without negatively affecting credit or liquidity thresholds.

Project bonds often entail construction risk, and guarantees could help to significantly reduce this risk and hence the cost of finance and overall project cost. This effect has already been witnessed in the US alternative energy sector with government loan guarantees during the construction of projects.

The other advantage of government guarantees would be that it would effectively give governments 'skin in the game'; given investors' perception that one of the largest single risks for many of the projects is regulatory, making the government a stakeholder would give greater comfort in the stability of regulation.

While governments have historically facilitated investment in alternative energy via feed-in tariffs, and investment or production tax credits to improve the relative economics of new forms of generation, as the LCOE's of these technologies improve, these mechanisms become less necessary. Accordingly, the capital freed up by the removal of these subsidies could be used to provide guarantees for certain types of investment.

Other Financial Instruments

While equity and evolving fixed income instruments will provide the bulk of the financing for the energy transition, there are other financial instruments and markets that will be no less important. The insurance industry has long been interested in the potential effects of climate change given the associated liabilities. Instruments have existed for decades to allow investors to effectively hedge weather risk – for example temperature (degree-days) based instruments in the gas/utilities sector offsetting demand volatility. However, instruments which provide insurance against wind volatility are also being developed, and could once again reduce risk and volatility in this and other green sectors, thereby improving credit quality.

Research and Development

The Global Apollo Programme advocates greater investment in R&D that could promote a faster transition into cleaner energy

While not strictly a financial instrument, another mechanism which could help to promote the energy transition is incentives to allow R&D investment into new technologies. Current R&D budgets into green projects, climate change and geoengineering are currently estimated at just $5.9 billion per year globally (Global Apollo Programme). As we have seen, this figure is dwarfed by historic levels of combined subsidies into both alternative and conventional energy of well over $500 billion. By facilitating greater investment in R&D, the cost of existing solutions could be reduced more rapidly, as well as increasing the chances of the emergence of new technologies (such as CCS) which could have a material impact on the cost and speed of the energy transition, as well as offering the potential for 'game-changing' discoveries.

The Global Apollo Programme, a group consisting of some of the world's leading industrial, political and scientific minds, advocates exactly this, believing that a significantly larger investment into R&D could promote much faster and cheaper transformation of the energy mix. The group's ultimate goal is that via a major R&D program using the best resources available globally, baseload wind and/or solar should become less costly than coal-based power, in every country.

The Green Climate Fund

One positive to come out of the (otherwise disappointing) Copenhagen COP meeting was the agreement to create by 2020 a $100 billion per year green climate fund, the idea of which was that funding provided by developed nations would be used to help fund the transition to a cleaner energy mix in developing nations.

While this has received relatively downbeat estimates of its likely effectiveness, we should not ignore its potential impact, given the relatively limited differential in costs (which are becoming ever smaller) between clean and conventional energy. In context that $100 billion could fund much of the differential in spend in early years, and help to promote energy efficiency.

The downside is that as yet, only $10.2bn of those funds have actually been mobilized. Moreover, the efficacy of an entity such as this will be crucial; it must not become bogged down in bureaucracy and politics, which given its very nature will be quite a challenge.

Conclusions

The UN COP21 meeting being held this December represents the first real opportunity to reach a global legally binding agreement for the reduction of greenhouse gas emissions. Other past meetings have failed to achieve this; however, this time it feels different — countries including all the big emitters seem to be coming to the table with positively aligned intentions, against a backdrop of an improving global economy, and with public opinion broadly supportive. At the time of writing, a total of 21 countries and 1 region, including the US, China and the EU have submitted their national pledges (INDCs) to reduce GHG emissions over time. Nevertheless, to achieve this accord will take brave, forward-looking and non-partisan decisions on the part of policymakers.

The sums of money at stake in terms of investment in the energy sector are staggering — we estimate at $190.2 and $192.0 trillion between 2015 and 2040 for Citi's 'Action' and 'Inaction' scenarios, respectively. The difference is marginal between the two scenarios; mainly due to the fact that although we spend more on renewable resources and energy efficiency in the 'Action' scenario, this is offset by savings in fossil fuels through lower usage and the lack of fuels used by wind and solar. However, going down the route of 'Inaction' would lead to a reduction in global GDP which could reach $72 trillion by 2060 depending on temperature increase, scenario and discount rate used. We calculate the implied return of incremental avoided costs on annual spend and even though the returns are not spectacular, in today's context of low yields, and certainly in the context of potential implications of climate change inaction on society and global GDP, and with the additional benefit of cleaner air, the 'why would you not' argument comes to the fore, an argument that becomes progressively harder to ignore over time.

Yet adopting this low carbon future will not be without pain for some. Switching to a low carbon energy future would mean that potentially significant quantities of fossil fuels that would otherwise have been burnt would remain in the ground. This concept known as stranded assets or unburnable carbon has recently come to the forefront of the discussion on climate change. Investors are becoming increasingly concerned with this issue, and have increased their engagement with fossil fuel companies to understand the potential risks to their investments. A study has shown that if we are serious about meeting the 'carbon budget' and have a chance of limiting temperature increase to 2°C, then globally one-third of oil reserves, half of gas reserves and 80% of coal reserves would have to remain in the ground; we estimate that the total value of stranded assets could be over $100 trillion based on current market prices. However, Citi research shows that some conventional resources are already effectively stranded from an economic point of view due to low commodity prices, whilst coal companies are already experiencing some considerable stress as can be seen from the dramatic fall in seaborne thermal coal prices.

It is not just policymakers that must think outside of the box; to provide the vast amounts of capital required in different and new industries and locations will require significant innovation on the part of financial markets and institutions. Much of the energy investment behavior that needs to be changed will be in emerging markets given their demand growth, and energy and carbon intensity, yet financial markets in these regions are often less sizeable, stable and liquid. There is enormous investor demand for low carbon investment, with investor groups representing tens of trillions of dollars under management committed to investing in a more environmentally friendly manner. The stumbling block to date has been the lack of, and in particular the quality of many of the investment opportunities available. Bridging the gap between investors and the need for investment will be key in facilitating our energy transformation. We believe that the credit markets offer perhaps the greatest scope to facilitate this investment, and we highlight the significant innovation which is taking place currently, which while in its infancy offers significant encouragement for the future, as well as potentially exciting and very large opportunities for the financial world.

Paris offers a generational opportunity; one that we believe should be firmly grasped with both hands.

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Tim Kruger is the James Martin Fellow in the Oxford Geoengineering Programme at the Oxford Martin School, University of Oxford. Tim Kruger leads a group across the University of Oxford exploring proposed geoengineering techniques and the governance mechanisms required to ensure that any research in this field is undertaken in a responsible way. He has investigated in detail one potential geoengineering technique, that of adding alkalinity to the ocean as a way of enhancing its capacity to act as a carbon sink and to counteract the effects of ocean acidification. He is a co-author of the Oxford Principles, a set of draft principles for the conduct of geoengineering research which have been adopted as policy by the UK government.

Professor Cameron Hepburn is the Director of the Economics of Sustainability Programme at the Institute for New Economic Thinking at the Oxford Martin School and a Fellow at New College, University of Oxford. He is an expert in environmental, resource and energy economics. He has degrees in law and engineering, a doctorate in economics, and over 30 peer-reviewed publications in economics, public policy, law, engineering, philosophy, and biology.

He is involved in policy formation, including as a member of the DECC Secretary of State's Economics Advisory Group. He has also had an entrepreneurial career, co-founding two successful businesses and investing in several other start-ups.Cameron is a member of the Economics Advisory Group (with Lord Stern and Professor Helm) to the UK Secretary of State for Energy & Climate Change. He served for almost a decade as a member of the Academic Panel, in the UK Department of Environment, Food and Rural Affairs and the Department of Energy and Climate Change. He has advised governments (e.g. China, India, UK, Australia) and international institutions (e.g. OECD, UN organisations) on energy, resources and environmental policy.

Cameron began his business career with work at oil multinational Shell, law firm Mallesons and then management consultancy McKinsey & Co. Cameron is now a founder-investor in the social enterprise and clean energy sectors. In 2006, with Alex Wyatt he co-founded Climate Bridge, a developer of clean energy projects in China and around the world, with offices in four countries. Also in 2006, with Robin Smale he co-founded Vivid Economics, a boutique economics consultancy where he has worked with private sector (and government) clients on strategy in relation to market structure and resource, energy and environmental issues.

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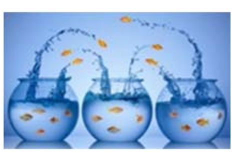

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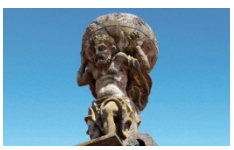

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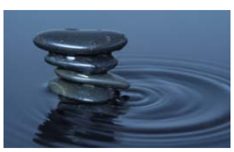

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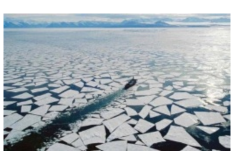

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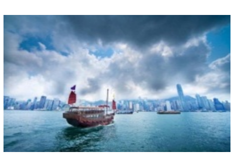

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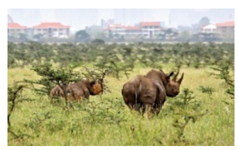

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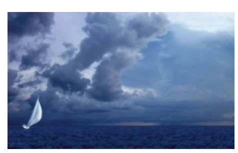

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Key Insights regarding the future of Climate Change

REGULATION

In 1988, the IPCC was created to assess the science of climate change and look at whether formal diplomatic talks would need to be undertaken to discuss the issue of greenhouse gas emissions. / In December 2015 heads of representative states will meet in Paris to discuss setting up a new binding international agreement with the aim of keeping global warming to 2°C and mobilize funds to allow developing countries to both adapt to and mitigate climate change impacts.

GLOBAL REACH

The world can largely ignore the implications for emissions and feed an energy-hungry planet with cheap fossil fuels to drive global economic growth. / The cost of inaction is not only the total energy spend on capex and fuel. The overall costs and risks of climate change including externalities such as health and environmental effects could total 0.7% to 2.5% of global GDP in 2060.

COMMODITIES

Emissions contained in current ‘reserves’ figures are around three times higher than the so-called ‘carbon budget’. / Switching to a low carbon energy future means that significant fossil fuels that would otherwise have been burnt will be left underground. Some studies suggest that globally a third of oil reserves, half of gas reserves and over 80% of current coal reserves would have to remain unused from 2010 to 2060 to have a chance of meeting the 2°C target.

Preparing New Zealand for rising seas:

Certainty and Uncertainty

November 2015

Parliamentary Commissioner for the Environment
Te Kaitiaki Taiao a Te Whare Pāremata

Acknowledgements

The Parliamentary Commissioner for the Environment would like to express her gratitude to those who assisted with the research and preparation of this report, with special thanks to her staff who worked so tirelessly to bring it to completion.

Photography

Cover photo: Rock armouring at Cooks Beach, Coromandel.
Source: Parliamentary Commissioner for the Environment archives

This report and other publications by the Parliamentary Commissioner for the Environment are available at: **www.pce.parliament.nz**

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Overview

Sunday 14th June this year was a beautiful windless day in Wellington. On such rare days the sea is usually like glass. But looking down on Lyall Bay, I was surprised to see huge rolling waves washing up the beach and across the road, scattering rocks the size of basketballs across a car park. A great storm in the Southern Ocean had generated giant waves that had travelled, weakening but unimpeded over hundreds of kilometres of sea, to be lifted on top of a king tide as they finally broke on Wellington's south coast.

The sea level rise that has already occurred played only a small part in what happened in Lyall Bay that day, but as the sea continues to rise, there will be more and more such 'flood events' as the scientists call them.

The subtitle of this report is *'Certainty and Uncertainty'*. It is certain that the sea is rising and will continue to do so for centuries to come. But much is uncertain – how rapidly it will rise, how different coastal areas will be affected, and how we should prepare. And we do need to prepare. After all, as an article in the New York Times put it this year: *"Human civilization is built on the premise that the level of the sea is stable, as indeed it has been for several thousand years"*.

The rising sea will lead to flooding on low-lying land near the coast, erosion of many beaches and 'soft' cliffs, and higher and possibly saltier coastal groundwater.

- Flooding of coastal areas will become more frequent, more severe, and more extensive.
- Erosion – a long-familiar problem around some of our coasts – will become more widespread.
- Groundwater linked to the sea will rise and possibly become brackish.

However, care must be taken with generalisations. Local features matter a great deal.

For instance, open unsheltered coasts experience the full force of the sea, so are more vulnerable to flooding than enclosed bays. Beaches regularly replenished with sediment are less prone to erosion. Groundwater problems are most likely to occur in land that has been reclaimed from the sea.

Natural hazards like earthquakes, volcanic eruptions, and river floods can happen at any time. In contrast, sea level rise is incremental and inexorable – its effects on our coast will unfold slowly for a period before accelerating. We must start planning, but there is enough time to plan and do it well.

Certainly the world, including New Zealand, needs to act urgently to reduce carbon dioxide and other greenhouse gas emissions. However, during this investigation, I have realised that the same urgency does not apply to much of the planning we need to do for sea level rise. Indeed, haste can be counter-productive.

Central government has provided some direction and guidance for councils, but it is time for a major review. Councils that have begun to plan for sea level rise have sometimes found themselves between 'a rock and a hard place'.

In a number of locations around the country, the setting of coastal hazard zones based on projections of future flooding and erosion has been challenged by affected homeowners. Receiving a letter saying that your property has been zoned as susceptible to flooding or erosion can come as a shock.

Homes are much more than financial equity. Such zoning and any regulations that follow must be based on a fair process and technical assessments that are both rigorous and transparent.

While these principles should hold for planning for any hazards under the Resource Management Act, planning for sea level rise is outside our experience – it is *terra incognita*.

Part of making such a process fairer is simply to slow it down into a number of steps. It is for this reason that I decided to include the four elevation maps in this report with more available on our website.

This was not an easy decision because I do not want to alarm people unnecessarily. But the first stage in a step by step process should be the provision of information, beginning with accurate elevation maps of coastal land. Note that the coloured areas on these maps in this report are not coastal hazard zones; they simply denote elevation above spring high tide levels.

The analysis used to generate the information for these maps shows that at least nine thousand homes lie less than 50 centimetres above spring high tide levels. This is more than the number of homes that were red zoned after the Christchurch earthquakes.

Also needed is a clear distinction between the role of technical analysts who undertake coastal risk assessments and the role of the decision-makers who sit around council tables.

Because current government policy on sea level rise emphasises the need to take a 'precautionary approach', technical analysts have been embedding 'precaution' into coastal risk assessments to varying degrees. This takes various forms such as assuming 'high end' amounts of sea level rise.

But undertaking a coastal risk assessment is very different from designing a building or a bridge where redundancy and safety factors are intrinsic to the design. Technical assessments of coastal risk should be based on best estimates of all the parameters and assumptions that are fed into the modelling. Decision-makers should then take the modelling outputs including estimates of uncertainty, and then openly and transparently decide how cautious to be in delineating hazard zones.

Clear communication is another vital component of a good process – there is a need to develop a *lingua franca* – a language that will bridge the gap between the experts and the rest of us. In one report, I was amused to discover a heavy downpour described as a 'subdaily precipitation extreme'.

One particular need is to avoid referring to 'one-in-50 year' or 'one-in-100 year' events. Not only is it difficult to understand, it is not a stable measure over time. The 'high water' caused by a storm surge riding on top of a king tide that is now expected to occur once every 100 years will occur more and more often as the sea rises.

There are aspects of planning for sea level rise that should be done with some urgency. One is concerned with the granting of consents for greenfields development. New suburbs and the expensive infrastructure they require should be viewed as long-term investments. We now see building new suburbs on land prone to liquefaction in much of the country as foolish. We should see allowing new subdivisions on vulnerable coastal land as equally foolish.

Another is the need to establish much more extensive monitoring systems. This is required before we can develop better models of shoreline erosion and accretion. Such monitoring is also needed for adaptive management, which will be the appropriate strategy in many cases. Adaptive management involves staging interventions over time as trigger points are reached.

Unusually, one of my recommendations in this report is to the Minister of Finance. It is not too soon to begin to consider the fiscal implications of sea level rise. Both central and local government will face increasing pleas for financial assistance – whether it be for building a seawall, maintaining an eroding coastal road, or, as will eventually happen, moving entire communities further inland.

As I write this, delegates from hundreds of countries are about to meet in Paris to try to hammer out a new agreement to slow the rate of climate change. I remain optimistic. What the world, including our small country, does now will affect how fast and how high the sea rises.

J. C. Wright

Dr Jan Wright

Parliamentary Commissioner for the Environment

1 Introduction

Over many millennia, the Earth's climate has cycled between ice ages and warm 'interglacial' periods. Over the last seven thousand years the climate has been relatively stable, but this is now changing. Increasing concentrations of carbon dioxide and other greenhouse gases in the atmosphere are trapping heat and the climate has begun to respond. One of the major and certain consequences is rising sea level.

Nowhere in our island nation is far from the sea, and most of us live within a few kilometres of the coast. Houses, roads, wastewater systems, and other infrastructure have been built in coastal areas with an understanding of the reach of the tides and the recognition that storms will occasionally combine with high tides to cause flooding.

However, with rising seas, tides, waves and storm surges will reach further inland than before, resulting in more frequent and extensive flooding. Along some coasts, erosion will increase and shorelines will recede. In some areas, the water table will rise.

The vulnerability of different coastal areas to the rising sea depends on many factors. Elevation – height above the sea – is the first factor that comes to mind when considering the potential impacts of sea level rise, but it is far from the only one. The shape of the coastline, the topography of the land and the seabed, the proximity to the sea, the presence of barriers such as sand dunes, and other local characteristics will affect what happens in different coastal areas.

Other consequences of climate change, such as changing wind and rainfall patterns, will also come into play, increasing or reducing the impacts of rising seas. For instance, more intense rainfall coinciding with storm surges will exacerbate coastal flooding.

Like other countries, New Zealand needs to prepare for rising seas.

Under New Zealand law, the enormously challenging task of planning for sea level rise is the responsibility of local government. It is challenging on many levels. For a start, it is technically complex, and the size and timing of impacts are uncertain. Perhaps the most difficult aspect is the impact on people's homes, which for many are not just their homes, but also their financial security.

1.1 Purpose of this report

The Parliamentary Commissioner for the Environment is an Officer of Parliament, with functions and powers granted by the Environment Act 1986. She provides Members of Parliament with independent advice in their consideration of matters that have impacts on the quality of the environment.

In 2014, the Commissioner released a report titled *'Changing climate and rising seas: Understanding the science'*. This report was written with the intent of making the science of climate change, and specifically sea level rise, accessible and relevant for New Zealanders.

This report follows on from the 2014 report. Its purpose is to:

- increase understanding of how sea level rise will affect New Zealand
- show how low-lying coastal areas around the country can be accurately mapped in a standardised way
- describe how some councils have begun to plan for sea level rise
- identify problems with, and gaps in, the direction and guidance provided by central government.

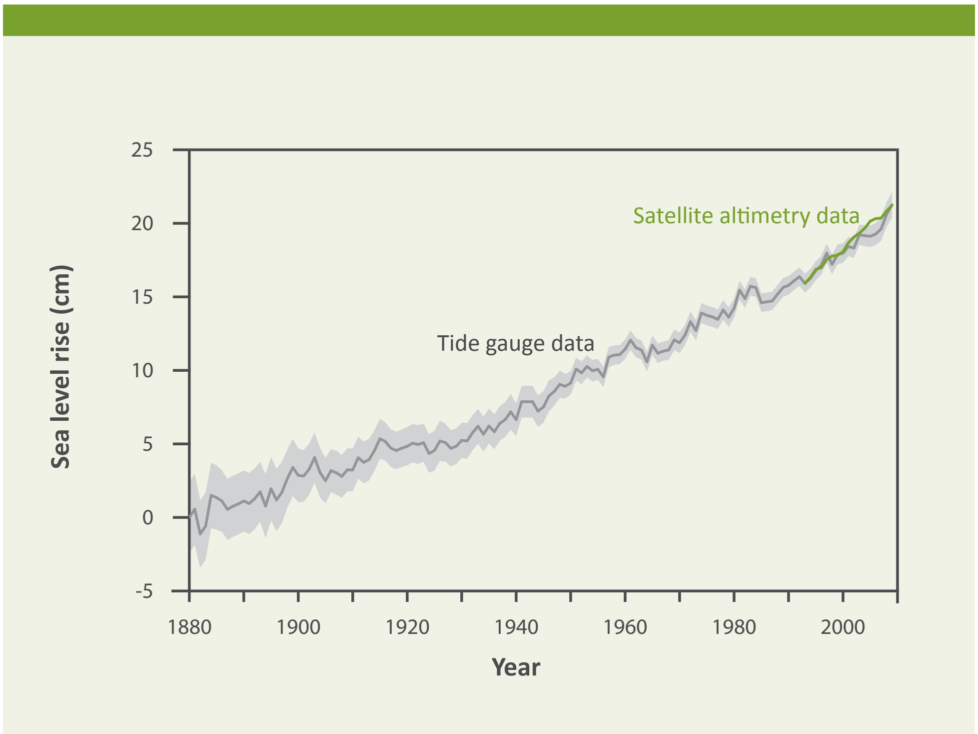
This report has been produced pursuant to s16 of the Environment Act 1986.

1.2 Rising sea level

Global average sea level has risen about 20 centimetres since the beginning of the 20th century.

Records collated from tide gauges at ports around the world show that average sea level began rising around 1900. In the last twenty-five years, satellites have enabled more precise measurement and greater global coverage (Figure 1.1).

This rise in global average sea level does not mean that the sea has risen by the same amount *everywhere* around the world. Changes in sea level at particular locations vary due to a number of factors. So far the seas around New Zealand have risen largely in line with the global average.



Data: Church and White, 2011.

Figure 1.1 Global mean sea level rise relative to 1880.

There are three main ways in which warming air temperatures are causing sea level to rise.

- Water in the sea is becoming warmer and expanding.
- Mountain glaciers are retreating.
- Polar ice sheets on Greenland and Antarctica are shrinking.

1.3 Adapting to sea level rise

Some countries, such as Bangladesh and Kiribati, will be greatly affected by sea level rise. But every country bordered by the sea will be affected in some way, and many are taking actions of various kinds to prepare for higher sea levels.

This section contains two examples of adaptation to sea level rise. The first is concerned with future-proofing an airport development. The second is the development of a strategy to protect a large city from flooding.

Building a new runway in Australia

A new runway at Brisbane Airport is currently under construction. The airport is situated on low-lying land close to the coast. Frequent tropical cyclones and other factors make the Queensland coast very vulnerable to coastal flooding, so in the planning it was critically important that the new runway be protected from flooding as the sea rises.

Several assessments were done to help decide what the height of the new runway should be, beginning with the then state guideline applicable to airports. The first step in such assessments is to use the most recent Intergovernmental Panel on Climate Change (IPCC) projections as the best guide available of future rates of sea level rise. Then other factors enter the calculations of design height – the height of storm surges and waves, the frequency of tropical cyclones, rainfall in the catchment, and so on.

Finally, a judgement must be made about the acceptable level of risk. Should the runway be high enough so that it never floods, or is a flood once a month tolerable? In the end, the decision was made to build the runway at a height described as *"strongly precautionary"*.[1] Airports are critical infrastructure. If a runway floods and aeroplanes cannot land, the financial consequences can be very large.

Source: J Brew, Wikimedia Commons (CC BY-SA 2.0)

Figure 1.2 Brisbane airport is situated on low-lying coastal land.

Protecting London

The Thames Barrier is a series of giant rotating gates spanning the River Thames that began operation in 1984. It is a major part of the system of defences designed to protect the city from flooding.

Flood risk in the Thames Estuary has increased over time. Half of the closures of the barrier have been to protect against tidal flooding and half to protect against river flooding. Both kinds of flood risk are expected to increase as the climate changes – tidal flooding because of sea level rise and river flooding because of more intense rainfall.

In 2002, a project called Thames Estuary 2100 was established to develop a strategy to protect the city through to 2100. Ten years later, the TE2100 Plan was adopted. Because the Thames Barrier was built to a high design standard, it is expected that it will not need to be modified until about 2070.

In the TE2100 Plan, a 'managed adaptive' approach has been adopted. This involves making several interventions over time to manage risk, in contrast with making *"a single, major investment in flood defence infrastructure or activity to achieve a reduction in risk which lasts until the end of the century"*.[2]

Source: James Campbell, Flickr (CC BY-ND 2.0)

Figure 1.3 The Thames Barrier protects London from tidal and river flooding.

In the first example, the elevation of a new runway at Brisbane Airport, a 'strongly precautionary' approach was taken. In the second example, the plan for protecting London against flooding, an 'adaptive management' approach was taken.

Both make sense. In the first case, the consequences of flooding on the runway would be so serious that the extra height was warranted. In the second case, the analysis showed that what was termed a precautionary approach would be expensive and environmentally damaging, and *"… run the risk of creating an expensive 'white elephant' should flood risk rise at a slower level than predicted"*.

These two examples illustrate that adaption to sea level rise needs a 'horses for courses' approach. In particular, different stances on risk will be appropriate for different situations. This, and other aspects of decision-making pertinent to sea level rise, are discussed in this report.

1.4 What this report does not cover

This report does not include any detailed discussion or analysis of the following:

- Climate change mitigation – reducing greenhouse gas emissions
- Other effects of climate change such as changing rainfall patterns, increased river flooding, and acidification of the oceans
- Impacts of sea level rise on coastal ecosystems and landscapes
- Ownership of the foreshore and seabed or any unresolved Treaty of Waitangi claims involving coastal land.

In particular, the report does not contain numerical estimates of the impacts of sea level rise in particular coastal areas around the country. Although some elevation bands are presented in maps, they do not denote coastal hazard zones, so are not suitable for including on Land Information Memoranda (LIMs).

1.5 What comes next?

The remainder of this report is structured as follows:

Chapter 2 contains a general description of some changes that lie ahead, beginning with the latest IPCC projections of sea level rise. It includes an explanation of why natural factors like storms change the level of the sea, and a brief description of how climate change is expected to affect rainfall, winds, and storms in New Zealand.

Chapter 3 is an explanation of how sea level rise will increase the frequency, severity, and extent of coastal flooding. It contains the results of modelling showing how extreme water levels will occur increasingly often. This modelling is based on the longest historic records of sea level in New Zealand, measured at the ports of Auckland, Wellington, Christchurch, and Dunedin.

Chapter 4 is an explanation of how sea level rise will increase the erosion of sandy beaches and 'soft' cliffs.

Chapter 5 is an explanation of the potential impacts of sea level rise on coastal aquifers. In some places the water table will rise as the sea rises. Another consequence may be saltwater intrusion.

Chapter 6 begins by explaining how the elevation of land above sea level can be measured accurately using a system called LiDAR. It contains maps showing low-lying coastal land in Auckland, Wellington, Christchurch, and Dunedin. More maps are available at **www.pce.parliament.nz**. The chapter also contains the results of running a software programme called RiskScape, showing numbers of homes and businesses, and lengths of roads at low elevations.

Chapter 7 begins with a look back into the past, describing how governments have dealt with the long-familiar coastal hazard of erosion. It then describes the two government documents that currently guide and direct councils in their planning for sea level rise. This is followed by four sections describing some of the problems that have arisen as some councils have begun to plan for sea level rise.

Chapter 8 contains conclusions and recommendations from the Commissioner.

Three modelling exercises were commissioned to provide information for this investigation – two from the National Institute of Water and Atmospheric Research (NIWA) and one from Dr John Hunter of the University of Tasmania. The methodology and results from this modelling are detailed in technical reports available at **www.pce.parliament.nz**.[3]

2

What lies ahead?

The level of the sea has already risen significantly due to the impact of humans on the climate, and will continue to do so for the foreseeable future.

The first section of this chapter contains the most up-to-date projections of the increase in sea level by the Intergovernmental Panel on Climate Change (IPCC).

While climate change is raising the level of the sea, there are a number of natural factors that influence the level of the sea at any given time. The second section is a brief description of these factors, ranging from exceptionally high tides through to long-term weather patterns.

Climate change is expected to affect the weather in a number of ways – described in the third section. Some of these will have impacts on coastal areas and need to be thought about in conjunction with sea level rise.

The final section introduces the three types of coastal hazards that will be exacerbated by sea level rise – flooding, erosion, and groundwater that rises too high or becomes saline.

2.1 How fast will the sea rise?

As air temperatures have risen around the world, water in the sea has warmed and expanded, and alpine glaciers have retreated. These two processes have driven most of the global sea level rise observed over the last hundred years or so. In the future, a third process – loss of ice from the huge ice sheets that cover Greenland and Antarctica – is expected to become increasingly significant. 'Ice sheet dynamics' is now the focus of much climate change research.

The IPCC undertakes regular assessments of the current state of knowledge about climate change. These include projections of global sea level rise.

In its most recent report in 2013, the projections were based on four scenarios. Each scenario is based on a different Representative Concentration Pathway (RCP) – a trajectory over time of greenhouse gas concentrations in the atmosphere.

The projected rises in sea level that the IPCC assessed as 'likely' under the lowest and highest of these scenarios are shown in the three graphs in Figure 2.1.[4]

- The first graph shows the projected rise in sea level under the 'Stringent mitigation' scenario (RCP2.6).
- The second graph shows the projected rise in sea level under the 'Very high greenhouse gas emissions' scenario (RCP8.5).
- The third graph shows the projected rise in sea level under both scenarios.[5]

An examination of Figure 2.1 reveals three important aspects of sea level rise.

- The projections for the end of the century are much more uncertain than those for the middle of the century. Uncertainty grows over time.
- Action taken to reduce greenhouse gas emissions will make little difference to the rate of sea level rise for several decades.[6]
- The two scenarios increasingly diverge in the latter half of the century. The sooner emissions are curbed, the greater the effect will be in the longer term.

Around New Zealand, the sea has so far risen at about the same rate as the global average, but may rise a little faster than the global average in the future.[7] How fast the sea will rise in different places around the country also depends on whether the land is rising or falling; this can occur slowly over time or rapidly in an earthquake.

The scenarios in Figure 2.1 are projections of sea level rise up to the year 2100.[8] This does not mean that the sea will stop rising at the end of the century – it will continue to rise for many centuries to come.[9]

Data: IPCC, 2013

Figure 2.1 The most recent projections of global mean sea level rise by the IPCC relative to 1986–2005. The green band represents the range for the RCP2.6 scenario, and the purple band represents the range for the RCP8.5 scenario. In the top two graphs, the lines represent the median of the range.

2.2 Natural variation in the height of the sea

The height of the sea around the coast naturally falls and rises as the tides ebb and flow, and the weather changes.

High astronomical tides

Tides are controlled by the gravitational forces of the Moon and the Sun pulling the Earth's water towards them. How high the tide reaches varies over time, with relatively high 'spring tides' occurring about every two weeks when the Earth, the Sun, and the Moon are aligned.

King tides are particularly high spring tides that occur about twice a year when the Earth, the Sun, and the Moon are aligned, *and* the Moon is closest to the Earth.

Storm surges

During a storm, high winds and low air pressure can combine to create a bulge in the level of the sea that is driven on to the coast. Such storm surges can be thought of as very long, slow waves.

In April 1968, Cyclone *Giselle* formed in the Coral Sea and began tracking toward New Zealand where it was reinforced by a storm from the south. A storm surge of 88 centimetres was measured on the tide gauge in Tauranga Harbour – the largest ever recorded in New Zealand. The waves reached 12 metres in Cook Strait and the *Wahine* sank in Wellington Harbour (Figure 2.3).[10]

Waves

Winds travelling over the surface of the sea create waves. How high waves get depends on the strength and duration of the wind, as well as the depth of the sea and how far the waves have travelled. If unimpeded by land, a wave can travel thousands of kilometres. Wellington's south coast is sometimes pummelled by huge swells that are generated by storms as far away as Antarctica (Figure 2.2).

As waves approach the land, they usually become smaller before they break and run up the shore. During storms, waves can reach several metres above the high tide mark along some coasts.

Long-term weather patterns

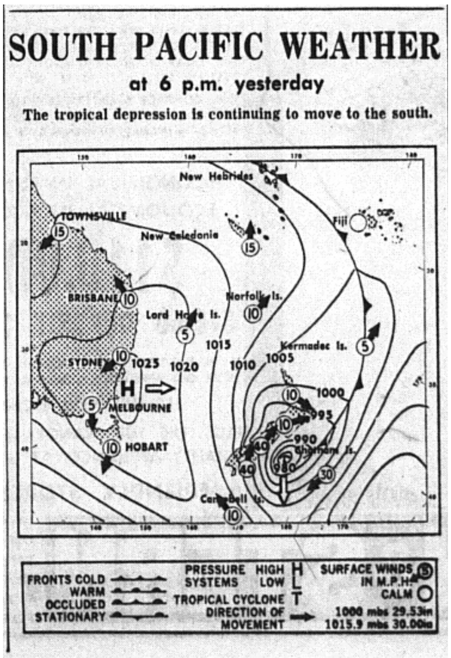
Long-term weather patterns can change the level of the sea over many years or even decades. During an El Niño phase of the Southern Oscillation, the level of the sea around New Zealand falls, and during a La Niña phase, it rises. Over longer timescales, the Interdecadal Pacific Oscillation also affects sea levels around New Zealand.[11]

Combined effect on sea levels

These natural causes of high sea levels can occur together, increasing their impact on coasts. In January 2011, a storm surge and a high astronomical tide overwhelmed stormwater systems and flooded parts of coastal Auckland.

Source: Erik Winquist

Figure 2.2 Waves breaking on the south coast of Wellington near the airport.



Source: New Zealand Herald

Figure 2.3 Air pressures over New Zealand on the day the *Wahine* sank in April 1968.

2.3 Changing rainfall, wind, and storms

In coming decades, weather patterns will continue to alter as the climate changes. Some changes in weather will affect coastal areas and need to be thought about in conjunction with sea level rise.

Rainfall

As the atmosphere warms, it can hold more moisture – about 7% for every 1°C increase in temperature.[12] As the climate changes, both the distribution of rainfall across New Zealand and its intensity are projected to change.

Rainfall is projected to increase in the west of both islands and in the south of the South Island. Northland and eastern regions of both islands are projected to become drier.[13] It is also projected that heavy downpours will become more extreme.[14]

Increases in the amount and intensity of rainfall in some catchments raise the risk of river flooding. Areas close to river mouths can experience the 'double whammy' of river flooding coinciding with the sea pushing its way upriver at high tide. As high tides become higher because of sea level rise, such floods will become more likely.[15]

Winds

The duration and intensity of winds drives the power of waves. As circulation patterns in the atmosphere change, westerly winds are projected to become more prolonged and more intense in New Zealand, especially in winter.[16]

Increased winds would lead to larger waves breaking on the shores of the west coasts of both islands.[17]

Storms

As the atmosphere becomes warmer, storm patterns are likely to change. Storm surges ride on top of the sea and can be driven on to land by wind – their impact will be increased by sea level rise.

It is projected that cyclones that form south of New Zealand in winter will become more intense, leading to stronger winds and larger waves on shores exposed to the south. It is also projected that the intensity of cyclones elsewhere in the country will decrease.[18]

2.4 Three types of coastal hazard

There are three types of coastal hazard in New Zealand that will be directly affected by rising sea level.

Flooding occurs along coasts when the sea flows over low-lying land.

Erosion occurs when waves and currents eat away at 'soft' shorelines.

Groundwater can be affected in two ways – water tables can rise and freshwater can become saline.

The next three chapters deal with each of these in turn.

There is another type of coastal hazard that will be affected by rising sea level – tsunamis. A tsunami is formed when an earthquake or landslide under the sea creates waves. The height of a tsunami when it reaches a shore can range from a few centimetres to tens of metres, and largely depends on the size of the event that caused it and the distance from its origin. Sea level rise will increase the height of tsunamis. Tsunamis are rare and unpredictable. They are not discussed further in this report.

Source: Anne Te Wake

Figure 2.4 Many marae and historical sites are located near the coast on low-lying land. This photo shows Mātihetihe marae on the coast north of Hokianga harbour. The hapū of Te Tao Mauī from Mitimiti are working with NIWA to understand how sea level rise might affect their marae.

3 Coastal flooding

Coastal floods occur when the sea rises above the normal high tide level and flows on to low-lying land.

Such floods range from 'nuisance events' to widespread costly inundation. Seawater may flow on to a waterfront promenade relatively frequently, but only cause traffic delays and inconvenience. Much more rarely, powerful storm surges can flood homes, damage roads, and close businesses.

The first section of this chapter describes the factors that make particular areas of the coastline vulnerable to flooding.

A rising sea will increase the frequency, the duration, and the extent of coastal flooding in New Zealand. The second section contains the results of modelling that shows how the frequency of extreme water levels will increase at four locations around New Zealand.

3.1 Vulnerability to coastal flooding

Different factors affect how vulnerable a coastal area is to being flooded by the sea.[19]

Elevation and distance from the coast

Areas that are low-lying and close to the coast are generally most vulnerable to flooding.

As floodwater spreads inland from the coast, it loses momentum. However, in some situations, storm surges can carry seawater a considerable distance inland.[20]

Shape of the coast

Open unsheltered coasts experience the full force of waves from storms, making them generally more vulnerable to flooding than enclosed bays and estuaries.

However, water carried by a storm surge can be funnelled by the shoreline of a narrowing harbour or estuary. This happened during the January 2011 coastal flood in Auckland, when the sea rose another 30 centimetres as the storm surge flowed through the Waitemata Harbour.[21]

Natural and built defences

Defences against the power of the sea can be natural like sand dunes, gravel banks, wetlands, and cliffs, or built like seawalls, earthen dikes, and tidal barriers. These defences may themselves be undermined by high seas and storms – natural defences can erode and built defences can collapse.

Natural defences can accrete as well as erode. The gravel bank on the beach along Marine Parade in Napier has grown over time as gravel carried down from the hills by the Tukituki River is carried by longshore currents and deposited on the beach.

Stormwater pipes

Stormwater pipes are designed to carry rainwater out to sea. However, if the sea is high enough to cover the pipe outlets, the rainwater can struggle to drain away. In some instances, seawater can run back up the pipes.

Stormwater pipes can be fitted with flap valves to prevent seawater from entering the system. Maintenance is also important – sediment sometimes settles into pipes after storms, and flushing is required to clear them.

Coastal floods often occur during storms, and stormwater systems sometimes cannot cope with both rainwater and seawater.

Source: Craig Thomson

Figure 3.1 In February 2015 a king tide caused minor flooding on boardwalks in Howick, Auckland. As the sea rises such nuisance flooding will occur every high tide in some places.

Source: Sam Gorham

Figure 3.2 Lowry Bay during the June 21st 2013 storm that saw many roads flooded around Wellington Harbour. On this day the tide gauge at the port recorded the highest sea level since records began in 1944.

3.2 A rising sea will increase coastal flooding

The rise in sea level that has already occurred means that king tides, storm surges, and waves now reach higher up shores than they used to. As the sea continues to rise the frequency, duration, and extent of coastal flooding will increase.

In some cases, the rising sea will increase the duration and extent of *river* floods, like the one that occurred in Whanganui in 2015. If such river floods peak at high tide, they will become more damaging as high tides become higher.

Some projections of the increased frequency of extreme water levels were commissioned for this report from NIWA and from an international expert, Dr John Hunter from the Antarctic Climate & Ecosystems Cooperative Research Centre at the University of Tasmania.[22] These projections are based on the longest historic records of sea levels in New Zealand, measured on tide gauges at the ports of Auckland, Wellington, Christchurch (Lyttelton), and Dunedin.[23]

Table 3.1 shows when hourly recording of sea level began at each of the four ports and on which days the sea reached its greatest heights – in relatively recent years. Many Aucklanders will readily recall what happened in January 2011, and many Wellingtonians will readily recall what happened in June 2013.[24]

Table 3.1 Sea level records at four New Zealand ports.

	Year recording began	Date of highest recorded level
Auckland	1903	23 January, 2011
Wellington	1944	21 June, 2013
Christchurch	1924	17 April, 1999
Dunedin	1899	15 June,1999

The results of the modelling are presented in Table 3.2 and Figure 3.3.[25]

For this report, it was decided to express these results in terms of exceedances of high water levels that are *currently* expected to occur only once every hundred years – today's '100 year event'.[26] As time goes on, such extreme levels will occur more and more often.

In New Zealand, sea level is projected to rise by about 30 centimetres between 2015 and 2065.[27]

For a rise in sea level of 30 centimetres, such extreme high water levels would be expected to occur about:

- Every 4 years at the port of Auckland
- Once a year at the port of Wellington
- Once a year at the port of Christchurch
- Every 2 years at the port of Dunedin.

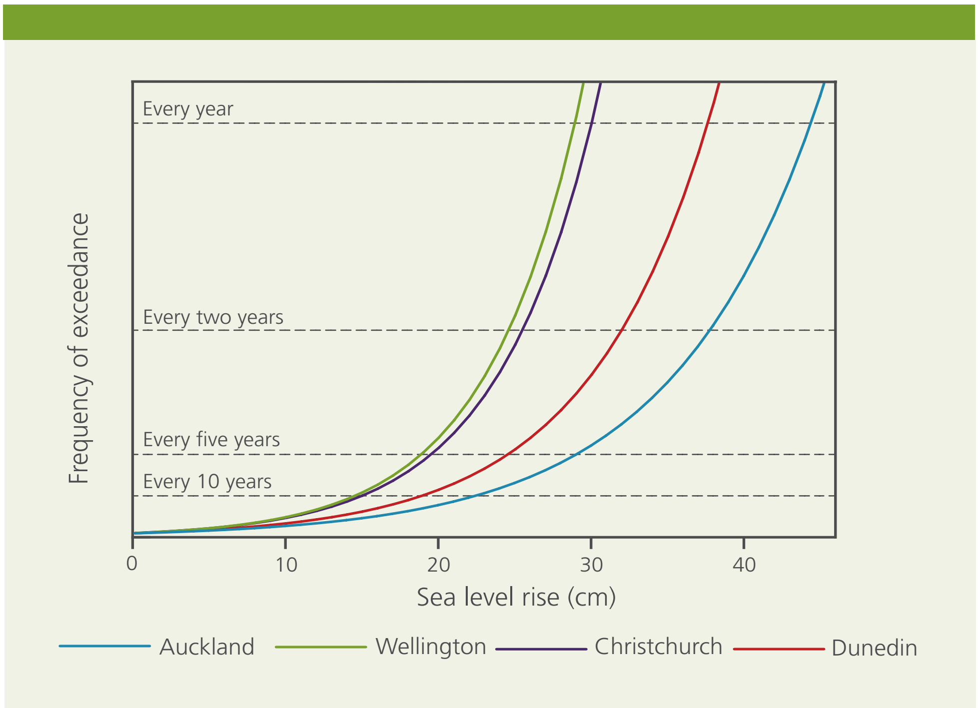
Table 3.2 Exceedances of today's '100 year events' occur more and more often as the sea level rises.

SLR	Auckland
0cm	Every 100 years
10cm	Every 35 years
20cm	Every 12 years
30cm	Every 4 years
40cm	Every 2 years
50cm	Every 6 months
60cm	Every 2 months
70cm	Every month
80cm	Every week
90cm	Twice a week
100cm	Every day

SLR	Wellington
0cm	Every 100 years
10cm	Every 20 years
20cm	Every 4 years
30cm	Once a year
40cm	Every 2 months
50cm	Twice a month
60cm	3 times a week
70cm	Every tide
80cm	Every tide
90cm	Every tide
100cm	Every tide

SLR	Christchurch
0cm	Every 100 years
10cm	Every 22 years
20cm	Every 5 years
30cm	Once a year
40cm	Every 3 months
50cm	Twice a month
60cm	Twice a week
70cm	Every day
80cm	Every tide
90cm	Every tide
100cm	Every tide

SLR	Dunedin
0cm	Every 100 years
10cm	Every 29 years
20cm	Every 9 years
30cm	Every two years
40cm	Every 9 months
50cm	Every 3 months
60cm	Once a month
70cm	Once a week
80cm	4 times a week
90cm	Every tide
100cm	Every tide



Data: Hunter, 2015

Figure 3.3 In the future, the tide gauges at the four ports will record exceedances of today's '100 year events' more and more often.

The shape of all four lines in Figure 3.3 is critically important for understanding how the frequency of coastal flooding will change in the future. All of the lines begin with a relatively flat section and then rise increasingly steeply. There is a period of time for each location before exceedances become common. But after this 'grace period', exceedances rise very rapidly.[28]

As with all modelling, careful interpretation is essential. Some important points include:

- The results show how often exceedances of the '100 year events' are expected to occur with sea level rise. They do not show the duration or extent of any flooding that may occur from these exceedances.
- No change in either the frequency or size of storm surges has been assumed in the modelling.
- Tide gauges do not measure wave height and waves are an important factor in some coastal flooding. Because waves ride on top of the sea, the higher the sea, the higher up the coast the waves will reach.

In assessing flooding risk from particularly high waters, local characteristics are critical. For instance, the records used in the modelling are from tide gauges at ports located in harbours that are more sheltered than coasts exposed to the open sea.

Although the four lines shown in Figure 3.3 have the same shape, they rise at different rates with Wellington at one extreme and Auckland at the other. By the time the sea has risen about 70 centimetres higher than it is now, every high tide at Wellington's port is expected to be higher than today's '100 year event' level. But it is not until the sea has risen over 100 centimetres that every high tide at Auckland's port is expected to be higher than today's '100 year event' level.[29]

This difference is due to the variation in high tide levels. High tide levels at Auckland's port vary over a wide range, so it takes a relatively large rise in sea level to push every high tide over today's '100 year event' level. In contrast, there is little variation in high tide levels at Wellington's port.

3.3 In conclusion

Coastal cities and towns have been developed over time with a stable sea level in mind. Buildings, roads, airports, wastewater systems and other infrastructure have all been built based on an historical understanding of the reach of the tides and occasional flooding during storms.

As the level of the sea continues to rise, areas of low-lying coastal land that currently flood during storms or king tides will experience more frequent and severe flooding. Areas a little higher will also begin to flood over time.

While the modelling results presented in this chapter do have limitations, they provide some useful insights, including the following.

- Each of the lines in the graph in Figure 3.3 begins with a relatively flat section, showing that there is some time for planning for the increased frequency of flooding that will come. How much time depends on the particular location.
- It is certain that the frequency of coastal flooding will increase as sea level rises. But the further ahead we look, the greater is the uncertainty in the modelling results.
- The results of such modelling are best plotted against centimetres of sea level rise. They can then be readily plotted against time for different IPCC scenarios.

Coastal erosion

Coastal erosion occurs when waves eat away at the land causing the shoreline to retreat. The sand and gravel stripped from a beach or cliff can be carried away by ocean currents. They can then be deposited out at sea or on another beach, causing it to build up – a process known as accretion.

The first section of this chapter describes the factors that make particular areas of the coastline vulnerable to erosion.

A rising sea can speed up erosion along some parts of the coastline and trigger it in others. This is illustrated with some examples from around the country in the second section.

The third section is a summary of the main points in this chapter.

4.1 Vulnerability to coastal erosion

Different factors affect how vulnerable a shoreline is to being eroded by the sea, whether it be long-term recession of the coastline or short-term cycles of erosion and accretion.

Coastal composition and shape

Sandy beaches are constantly changing. Sand is light and easily suspended in water, allowing it to be readily moved around by waves and currents. In contrast, pebbles from gravel beaches tend to be tossed around by the breakers and dropped back on the beach, sometimes piling up to form steep terraces. In New Zealand, mixed sand and gravel beaches are common.

Unlike beaches, cliffs can only erode – there is no natural process to build them up again. The composition of cliffs is important – cliffs made of silt or soft rock, for instance, are prone to erosion.

As for coastal flooding, erosion is more likely to happen on open coasts that bear the brunt of storm surges and larger waves, than on naturally sheltered coastlines, such as harbours or estuaries.

Size and shape of waves

Episodes of erosion often occur during storms. Storm surges take waves high up beaches, and strong winds generate large steep waves that can remove sand and deposit it on the seabed just offshore.[30] In calm weather, smaller flatter waves tend to deposit sand on to shores, helping beaches to accrete.

For a shoreline to be stable, stormy periods with large eroding waves must be balanced by long periods with smaller accreting waves. Significant erosion often occurs if there is a series of storms over a short period of time.

The balance between erosion and accretion can change over time when the size and direction of waves is influenced by weather cycles. In the upper North Island, beaches on the east coast tend to erode during a La Niña, while west coast beaches tend to erode during an El Niño.[31]

Sediment availability

Sediment – which includes both sand and gravel – naturally moves around the coast. Longshore currents run parallel to the shore and can carry sediment away. But those same currents may also bring sediment into the vicinity of a beach, allowing waves to deposit it on the shore.

Most of this sediment comes from erosion inland and has been carried down rivers to the sea. The supply of sediment varies over time and is influenced by many factors including storms, earthquakes, deforestation, dams, and changes in river flow.

Coastal scientists use the term 'sediment budget' to refer to the balance between the sediment that is removed from and the sediment that is added to different sections of coastlines and rivers.

A deficit will generally lead to net erosion and a surplus will generally lead to net accretion – rather like a bank account.

Built defences

Different kinds of structures, such as seawalls, can be built to prevent or slow coastal erosion.

Piling up large rocks against vulnerable shores is known as 'rock amouring' or 'rip-rap'. The road that runs between Wellington airport and the sea is protected in this way. While this approach may protect the land behind, sand in front of the rocks can be stripped away.

Groynes are barriers running out from the shore that can capture sediment as it is carried along by longshore currents. While groynes can protect a beach from erosion, they can also cut off the sediment supply to neighbouring beaches.

Built structures can also drive localised accretion. Caroline Bay in Timaru has changed markedly since 1878, when a breakwater was constructed to protect the harbour from southerly swells. Thousands of cubic metres of sand have since accumulated on the beach, and the shoreline has advanced hundreds of metres. However, nearby stretches of the coast have experienced accelerated rates of erosion due to the disruption of their sediment supply.[32]

4.2 A rising sea will increase coastal erosion

As the sea rises, erosion will increase in many places around the coast.

High-energy storm waves will rush further up beaches and reach higher up soft cliffs. Thus, beaches and cliffs that are prone to erosion are likely to erode faster.

Stable beaches may also begin to erode, and beaches that are accreting may accrete more slowly or begin to erode.

Waihi Beach on the east coast of the Coromandel, Haumoana in Hawke's Bay, and Beach Road south of Oamaru are three places where coastal erosion is clearly evident, and almost certain to increase as the sea continues to rise.

In places where the shoreline is advancing seaward, it may be many years before the sea rises enough to overcome the processes driving the accretion. The sediment supply is critical. Eastbourne in Wellington has changed from a retreating sandy beach to an advancing gravel beach, although the sea has been rising for a hundred years or so.[33]

Source: Western Bay of Plenty District Council

Figure 4.1 Waihi Beach is subject to episodes of erosion when storms gouge sand out of the dunes.

Source: Parliamentary Commissioner for the Environment archives

Figure 4.2 At Haumoana in Hawke's Bay, the land subsided about 70 centimetres during the 1931 earthquake. The earthquake also altered the sediment supply coming down nearby rivers. Since then the shoreline at Haumoana has moved about 40 metres inland.[34]

Source: Fairfax NZ

Figure 4.3 Beach Road south of Oamaru runs along the top of soft cliffs which have been eroding for thousands of years.[35] Soft cliffs do not undergo periods of erosion and accretion – they only erode.

4.3 In conclusion

Erosion (and accretion) around much of the coastline of New Zealand is a natural process that has been happening for thousands of years.

Councils have long been dealing with some of the consequences of erosion. Carparks, access ramps, and other public amenities have been relocated, and sections of some roads have been lost. Breakwaters and groynes have been built as defences and the odd building has fallen into the sea.

As the sea rises, cycles of erosion and accretion on beaches will change. The net effect of a higher sea will generally be increased erosion because the high-energy waves that strip sediment will reach further up shores.

As with coastal flooding, generalisations can be misleading. But when it comes to soft seaside cliffs that are already eroding, it is possible to generalise with reasonable confidence – the rate of erosion along such shorelines will increase.

5

Coastal groundwater

Groundwater sits in the spaces between soil and sediment particles, and within rock fractures. In many parts of the country, groundwater is used as a key source of water for drinking, industry, and agriculture. Most groundwater extracted in New Zealand is taken from coastal aquifers.[36]

When flooding and erosion occur along the coast, the impact is evident. But groundwater problems are not generally visible and are difficult to measure. Some issues associated with coastal groundwater can be expected to become more significant as the sea rises.

In some places, the groundwater will rise as the sea rises. The first section of this chapter describes the problems caused by high groundwater.

Another consequence of rising sea level will be more seawater moving into coastal aquifers. The second section of this chapter describes why saltwater intrusion occurs and why rising sea level could reduce the availability of freshwater in some places.

5.1 High groundwater

In some coastal areas, the water table is not far below the ground and is connected to the sea. As the level of the sea rises, the water table will rise in these areas.[37]

High groundwater causes a number of problems.

- Boggy ground and surface ponding.
- Damage to infrastructure and buildings.
- Saturated soil raising the risk of liquefaction in earthquakes.

Areas of land reclaimed from the sea are especially likely to experience problems caused by high groundwater.

South Dunedin is an area where such problems were clearly evident when prolonged heavy rainfall in June 2015 led to extensive flooding because the rainwater could not drain away. Much of South Dunedin is built on what was once a low-lying coastal wetland, and the water table is close to the surface, with many direct underground connections to the sea.[38] The water table rises and falls with the tides – in some places, builders know to wait for the tide to go out before excavating.

As the level of the sea rises, the water table in South Dunedin – and in some other coastal areas in New Zealand – will be affected.[39] A rising water table will lead to surface ponding in some places and more extensive flooding after heavy rain. It will also damage roads, pipes, and cables, as well as the foundations of buildings, particularly if the groundwater becomes saline.

A coastal aquifer does not have to be directly connected to the sea to be influenced by sea level rise. Where an aquifer extends out under the sea, changes in the weight of the water above it can increase the pressure on the aquifer, forcing the water table closer to the surface.

High groundwater can also increase the damage caused by earthquakes. When unconsolidated soils that are saturated with water are shaken in an earthquake, the soil can behave like a liquid. The citizens of Christchurch are all too familiar with the phenomenon of liquefaction.

Areas of reclaimed land are particularly prone to liquefaction. Because rising sea level will generally push up groundwater in these areas, the risk of liquefaction will increase.[40]

Source: Hocken Collection, University of Otago

Figure 5.1 In 1864, artist Andrew Hamilton painted *'Dunedin from the track to Andersons Bay'*. Much of South Dunedin is built on what was once a marshland of lagoons, rushes, and tussock.

Source: Otago Daily Times

Figure 5.2 Heavy rainfall caused flooding and damage in Dunedin in June 2015 when the stormwater system could not cope with the deluge.

5.2 Saltwater intrusion

Sea level rise also increases the potential for saltwater to enter freshwater aquifers.

Coastal aquifers can become contaminated with saltwater when freshwater is extracted at a rate faster than it is replenished. This seems to be a relatively minor problem in New Zealand.

The Waiwhetu Aquifer supplies more than a third of Wellington's water demand. This coastal aquifer extends off the Petone foreshore, and so the risk of saltwater intrusion must be actively managed. Sea level rise is expected to reduce the amount of freshwater that can be extracted from this aquifer.[41]

The Hawke's Bay iwi Ngāti Kahungunu is concerned about the potential for sea level rise to adversely affect the Heretaunga Aquifer. Groundwater scientists from GNS Science are investigating.

Low-lying Pacific atolls are especially vulnerable to flooding and salinisation of groundwater as the sea rises. Such atolls are porous so rainwater seeps directly through to the freshwater layer that floats on the seawater below the ground. On some of these islands, the freshwater has become brackish. One cause of this is waves overtopping and washing over the shores, and this will occur more frequently as the sea rises.[42]

Source: Wikimedia Commons (CC BY-SA 3.0)

Figure 5.3 Giant swamp taro is one of the crops being affected by increasingly saline groundwater.

5.3 In conclusion

Interactions between groundwater and seawater are highly localised and complex, and it is uncertain how groundwater in many places will respond as the sea rises. Predicting impacts on aquifers is made particularly difficult by the 'invisibility' of groundwater and a scarcity of information.

Those places where groundwater is linked directly to the sea are most likely to be affected.

This is particularly the case for groundwater beneath land that has been reclaimed from the sea. After heavy rain in South Dunedin in June this year, the problems that can be caused by a high water table were all too evident with flooded properties and damaged roads. A rising sea will slowly push the water table higher in South Dunedin and some other coastal areas.

Another potential consequence of sea level rise is increasing saltwater intrusion into coastal aquifers that are used as water sources. Saltwater intrusion is already causing serious problems for some of New Zealand's Pacific neighbours.

6

Low-lying and close to the coast

Areas that are both low-lying *and* close to the coast are, in general, most vulnerable to sea level rise. This is certainly the case when it comes to coastal flooding and rising groundwater. Erosion is rather different – a shoreline need not be low-lying to be eroded.

This chapter contains a number of maps showing areas in New Zealand that are both low-lying and close to the coast. Such maps are a necessary early step in assessing what is at risk as the sea rises. But, as has been emphasised in earlier chapters, local characteristics are also vitally important. For instance, a low-lying area close to the coast may be protected by a headland or a natural barrier such as a sand dune. And groundwater will only be a problem if it is connected to the sea.

The first section of this chapter describes how elevation above sea level can be measured accurately using a technology known as Light Detection and Ranging (LiDAR). During this investigation, NIWA was commissioned to convert the available LiDAR data into a standardised form. Once this was done, NIWA used RiskScape software to estimate how much of the built environment is at risk from sea level rise.[43]

The second section contains maps showing low-lying coastal areas in four cities – Auckland, Wellington, Christchurch and Dunedin. These four cities were chosen to provide a link with the modelling results in Chapter 3. Each map is accompanied by a short commentary that contains some RiskScape data. The purpose in this chapter is to give a sense of the information that is now readily available.

The impact of sea level rise will be felt in many other areas outside of these four major cities. Maps of these and other coastal areas have also been prepared in the course of this investigation, and are available at **www.pce.parliament.nz**. The third section contains commentaries on five other cities and towns that have significant areas of low-lying coastal land – Napier, Whakatane, Tauranga, Motueka, and Nelson.

6.1 Elevation maps and RiskScape

Two types of topographic datasets that can be used to map the elevation of coastal areas are available in New Zealand.

The first is the 'national-enhanced Digital Elevation Model'. While the dataset covers the entire country, the measurement of elevation is only accurate to 3 or 4 metres, so it cannot be used as a basis for analysing the impacts of sea level rise.

The second has been created from LiDAR technology. Pulses of light from a laser on an aeroplane are bounced off the ground, and the time taken for the reflected pulse to return is used to measure the elevation of the ground. Topographic surveys using LiDAR are typically accurate to 10 to 15 centimetres, so can be used as a basis for analysing the impacts of sea level rise.[44]

LiDAR elevation data is only available for parts of the country where councils have commissioned it (see Figure 6.1).[45] In the past LiDAR surveying has been very expensive, but is becoming cheaper.

The LiDAR elevation data used in this investigation has been standardised by NIWA to a common baseline – the average spring tide, technically known as 'mean high water springs'.[46,47] Note that the maps show elevation only – low-lying areas that are not directly connected to the sea are included in these maps.

In this chapter, maps of four major coastal cities – Auckland, Wellington, Christchurch, and Dunedin – are presented. Three different elevation bands – less than 50 centimetres, 50 to 100 centimetres, and 100 to 150 centimetres – are shown on the maps.

These maps are not suitable for detailed local level assessments, which must take into account many factors like exposure to storm surges and large waves.

Note also that the local elevation bands shown on the maps are not hazard zones, and should not be interpreted as such.

The RiskScape software programme has been used to find how many buildings, and which roads, railways, and airports are located within the different elevation bands.[48] Underground infrastructure – electricity and gas, telecommunications, drinking water supply, and wastewater and stormwater systems – will also be affected by sea level rise, but were not included in the analysis commissioned from NIWA.

Much of the natural character of the coast will also be affected by sea level rise, but RiskScape only covers the built environment.

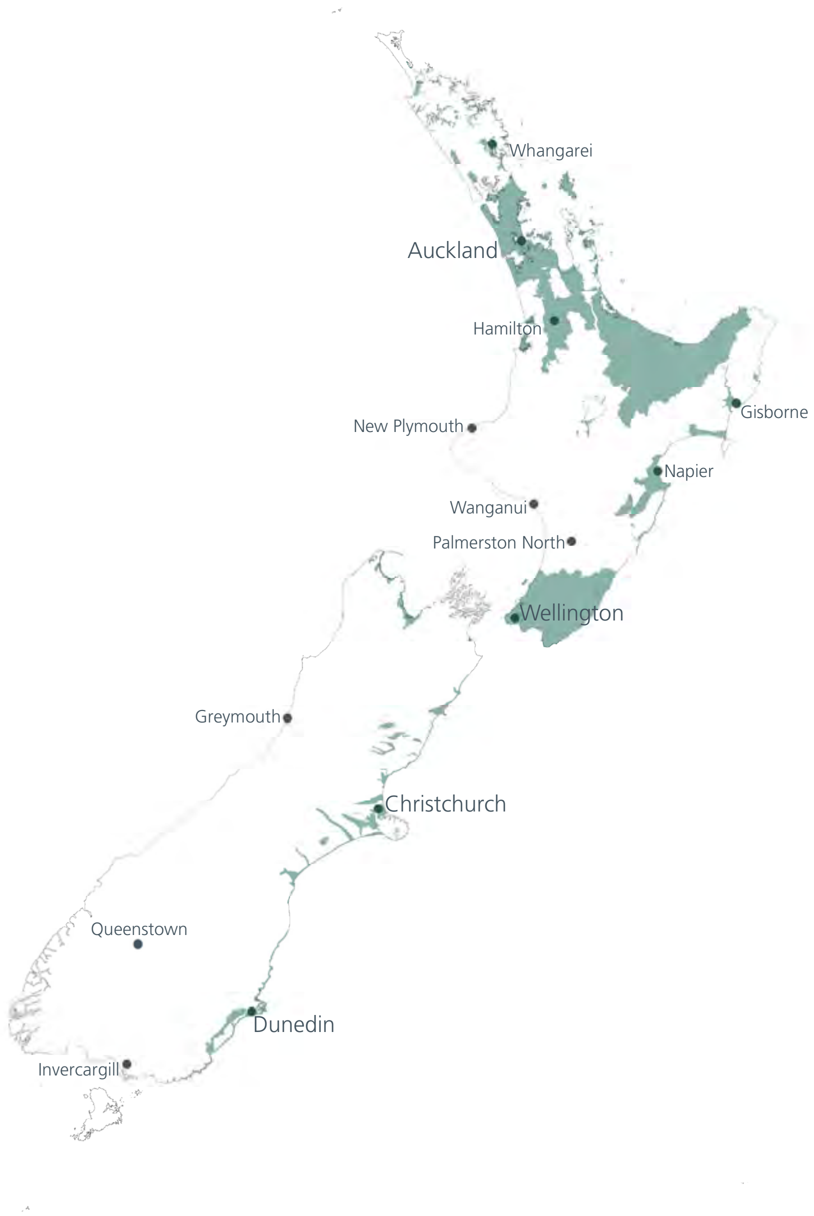


Figure 6.1 Areas where LiDAR elevation data has been obtained and made available for use in this report.

6.2 Four coastal cities

Auckland

Compared with other coastal towns and cities in New Zealand, a relatively small proportion of Auckland is low-lying.

Table 6.1 Low-lying homes, businesses and roads in Auckland.[49]

	0–50 cm	50–100 cm	100–150 cm	Total (0–150 cm)
Homes	108	457	795	1,360
Businesses	4	13	43	60
Roads (km)	9	18	29	56

Major low-lying areas shown in Figure 6.2 have not been densely built on. For instance, the large area below 50 centimetres in Devonport is a golf course, another in Northcote is the Onepoto Domain, and a third in Mangere is farmland. These areas are connected to the sea but sheltered from direct wave action.

There are pockets of low-lying land in the city, including parts of the Central Business District, Mission Bay, Kohimarama, St Heliers, Onehunga, Mangere Bridge, and Devonport.

About half of the low-lying homes in Auckland are situated along the coast in the north of the city.

There are also some relatively large areas of low-lying land along the west coast outside the Auckland urban area, which are not shown on the map. These include parts of the towns of Parakai and Helensville that lie close to the Kaipara River. Further south, the beach at Muriwai, though not as low-lying, has been eroding at a rate of about a metre a year since the 1960s.[50]

Vulnerable transport links include the Northern Motorway just north of the Harbour Bridge and the causeway on the Northwestern Motorway where it crosses the mud flats at Waterview. The latter is currently being raised by 1.5 metres and widened, partly to allow for gradual sinking into the soft marine mud and partly to allow for sea level rise.

Tamaki Drive, an important arterial road that provides access to the eastern suburbs, is also subject to flooding, most frequently where it crosses Hobson Bay.

Part of the western end of Auckland Airport lies less than 150 centimetres above the spring high tide mark, with 180 hectares built on reclaimed land and protected by sea walls.[51]

Figure 6.2 Low-lying coastal land in Auckland.

Wellington

Like Auckland, Wellington has about 100 houses that are lower than 50 centimetres above the spring high tide mark, but there are many more at slightly higher elevations.

Table 6.2 Low-lying homes, businesses, and roads in Wellington.[52]

	0–50 cm	50–100 cm	100–150 cm	Total (0–150 cm)
Homes	103	1,920	2,985	5,008
Businesses	1	20	139	160
Roads (km)	2	21	35	58

Figure 6.3 shows that most low-lying areas in Wellington are on the floodplain of the Hutt River – in Petone, Seaview, and Waiwhetū. The more pressing issue for this area is river and stream flooding. However, rising sea level will exacerbate such river floods by reducing the fall to the sea.

There are also small pockets of low-lying land in the Wellington Central Business District, Kilbirnie, Eastbourne, and around Porirua Harbour. Some of these areas have been reclaimed from the sea, so are generally more vulnerable to sea level rise.

Sections of State Highway 1 near Porirua Harbour, Cobham Drive (the main road to the airport), and Marine Drive (the only road to Eastbourne) are low-lying. An upgraded sea wall that reflects waves back out to sea has been proposed for Marine Drive.[53] The Esplanade that runs around the south coast of Wellington is generally higher, but is often pummelled by huge storm waves.

The rail line that runs around the top of the harbour is 2 to 3 metres above the spring high tide mark, but has nonetheless been damaged by high seas in the past. Trains do not have alternative routes, and when a storm washed out the seawall protecting the track in June 2013, it took almost a week to restore the service.[54]

Wellington's airport has been built on reclaimed land that is more than 3 metres above the spring high tide mark.

Figure 6.3 Low-lying coastal land in Wellington.

Christchurch

A relatively large proportion of land in Christchurch is low-lying.

Table 6.3 Low-lying homes, businesses, and roads in Christchurch.

	0–50 cm	50–100 cm	100–150 cm	Total (0–150 cm)
Homes	901	3,629	5,427	9,957
Businesses	5	58	130	193
Roads (km)	40	77	84	201

A map showing low-lying land in Christchurch prior to the 2010 and 2011 earthquakes would look rather different from Figure 6.4. In parts of Christchurch, land sank by as much as a metre or more, particularly along the lower reaches of the Avon River. Where land has sunk, water tables lie closer to the surface – this along with other changes has made these areas more prone to flooding.[55]

A considerable amount of low-lying land shown on the map is in the Residential Red Zone and so has been largely cleared of buildings. The numbers of homes and businesses listed in Table 6.3 do not include any in the Residential Red Zone.

Despite this, there are many more low-lying homes in Christchurch than in Auckland or Wellington – around the rivers and in the coastal suburbs.

Sand dunes run the length of the New Brighton coastline and provide some protection from the open coast to the low-lying areas behind. On Southshore, located on a spit between the open coast and the estuary, the lowest-lying land is on the estuary side.

Main Road that leads round the coast to Sumner is particularly low-lying, although somewhat protected by a seawall. This is currently the only access road to Sumner, since the other road in has been closed since the earthquakes.

As in Auckland, some large areas that are less than 50 centimetres above the spring high tide mark are not built up. For instance, the large area in Burwood is the Travis Wetland.

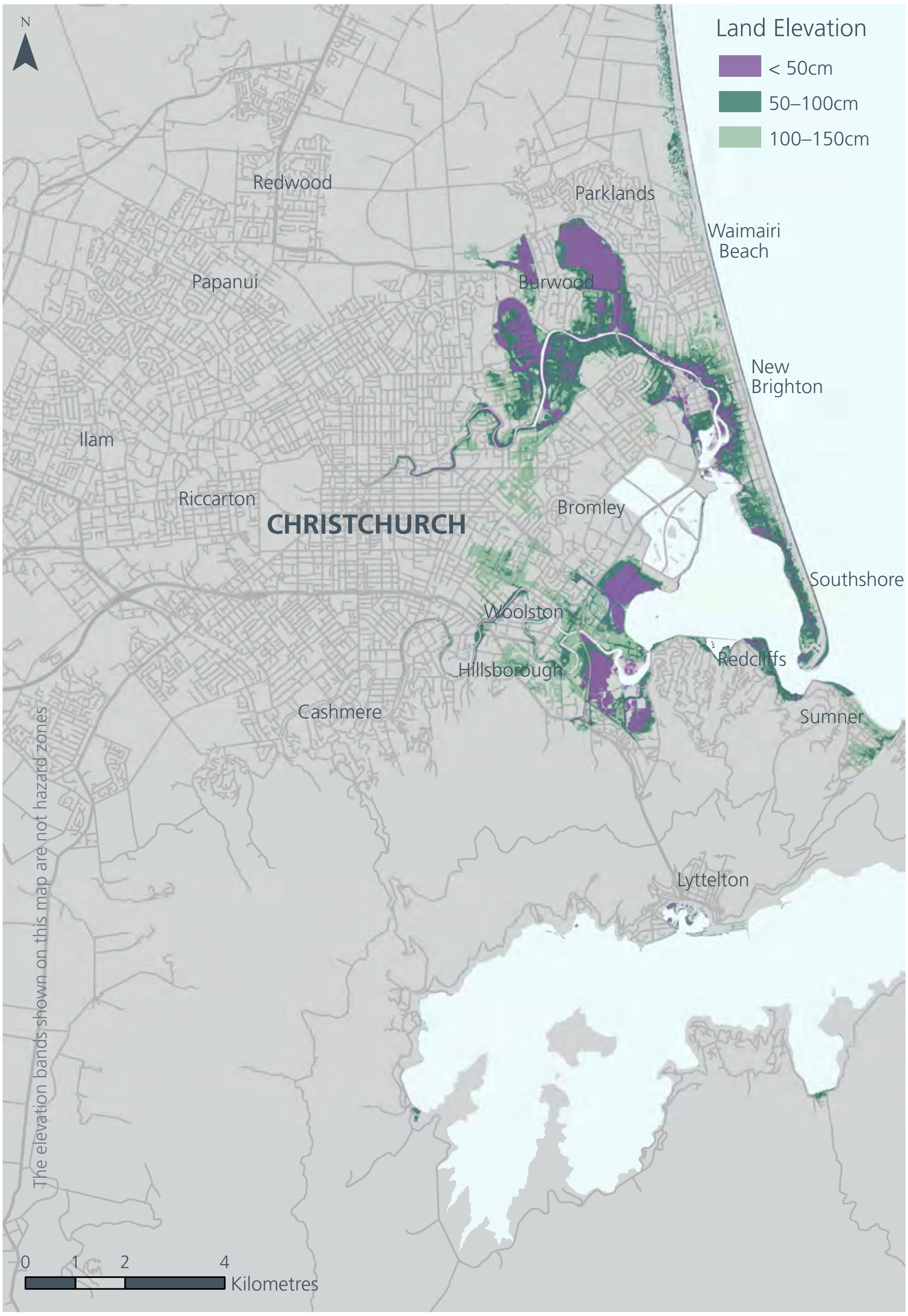


Figure 6.4 Low-lying coastal land in Christchurch.

Dunedin

Dunedin is notable for the large built-up area in the city's south that is very low-lying (Figure 6.5).

Table 6.4 Low-lying homes, businesses, and roads in Dunedin.

	0–50 cm	50–100 cm	100–150 cm	Total (0–150 cm)
Homes	2,683	604	317	3,604
Businesses	116	29	40	185
Roads (km)	35	17	20	72

As discussed in Chapter 5, South Dunedin was built on land reclaimed from a coastal wetland. Of the nearly 2,700 homes that lie less than 50 centimetres above the spring high tide mark, over 70% are lower than half that elevation.

The low elevation of South Dunedin along with its high water table makes it prone to flooding after heavy rain. The water table also rises and falls with the tides, so these problems will increase as high tides become higher.

The seawall protecting the St Clair esplanade in South Dunedin has required considerable maintenance and reinforcement in the wake of heavy seas over the last two years.[56]

Beyond South Dunedin, some areas of the waterfront and Central Business District are low-lying. These include sections of State Highway 1 and Portsmouth Drive. Portobello Road and Aramoana Road that run along either side of the harbour also have low-lying sections, with some places less than 100 centimetres above the spring high tide mark.

The rail line to Port Chalmers is an important link in the region's transport infrastructure. Much of it lies less than 150 centimetres above the spring high tide mark.

Dunedin Airport lies on the floodplain of the Taieri River and floods from time to time. The level of the water in the river fluctuates with the tides, and will be affected by sea level rise.[57]

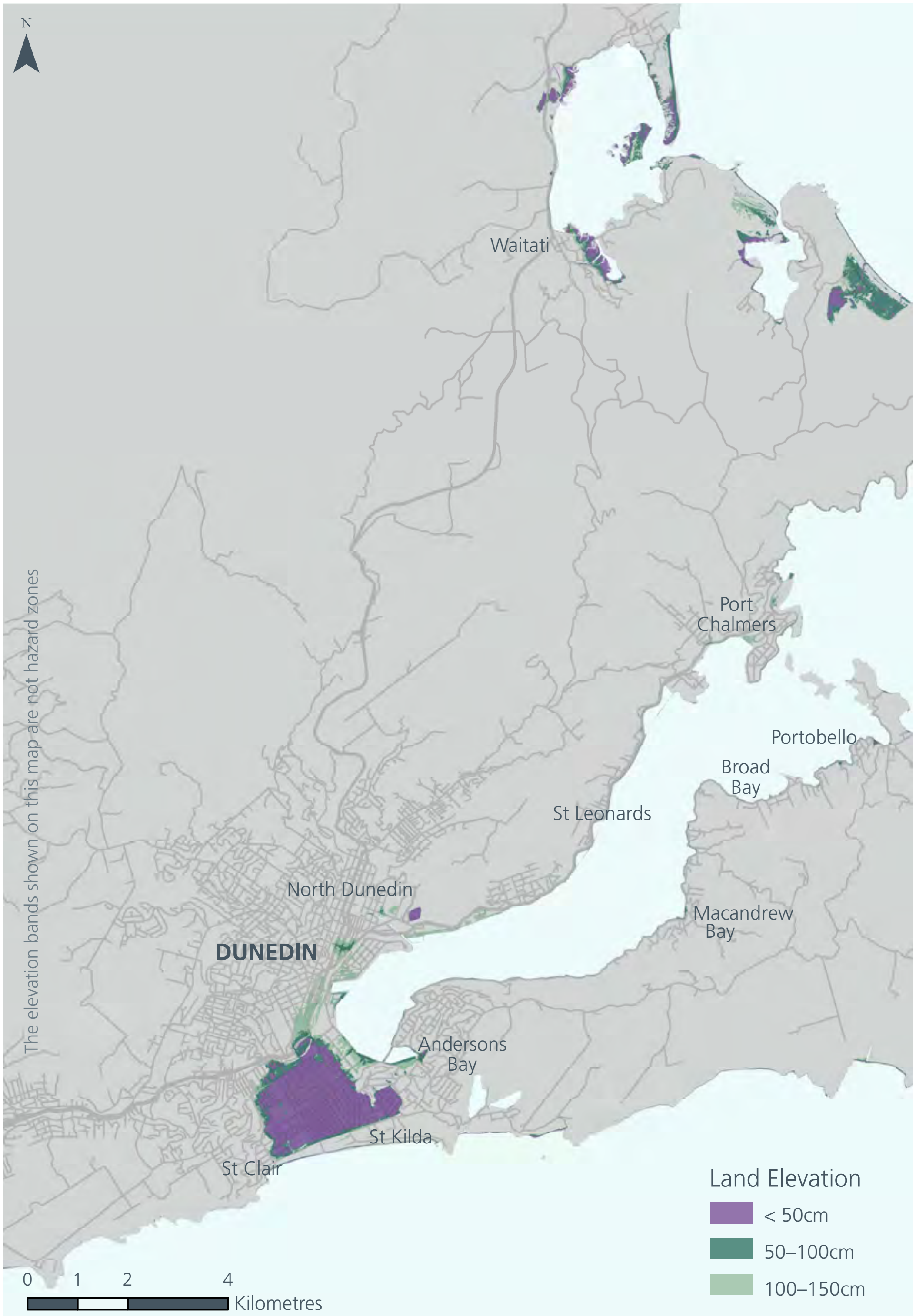


Figure 6.5 Low-lying coastal land in Dunedin.

6.3 Other coastal towns and cities

It is not just the four main cities in New Zealand that will be affected by rising seas. Many smaller towns and coastal settlements have also been built on the coast.

Running the RiskScape programme shows that there are five more cities and towns with more than a thousand homes lying less than 150 centimetres above the spring high tide mark – Napier, Whakatāne, Tauranga, Motueka, and Nelson.[58]

Table 6.5 Low-lying homes, businesses, and roads in Napier.

	0–50 cm	50–100 cm	100–150 cm	Total (0–150 cm)
Homes	1,321	2,958	3,694	7,973
Businesses	12	32	32	76
Roads (km)	37	59	49	145

Table 6.6 Low-lying homes, businesses, and roads in Whakatāne.

	0–50 cm	50–100 cm	100–150 cm	Total (0–150 cm)
Homes	276	563	470	1,309
Businesses	4	48	54	106
Roads (km)	9	15	14	38

Table 6.7 Low-lying homes, businesses, and roads in Tauranga

	0–50 cm	50–100 cm	100–150 cm	Total (0–150 cm)
Homes	77	419	735	1,231
Businesses	4	22	81	107
Roads (km)	3	14	18	35

Table 6.8 Low-lying homes, businesses, and roads in Motueka.

	0–50 cm	50–100 cm	100–150 cm	Total (0–150 cm)
Homes	45	390	618	1,053
Businesses	0	3	0	3
Roads (km)	4	7	8	19

Table 6.9 Low-lying homes, businesses, and roads in Nelson.

	0–50 cm	50–100 cm	100–150 cm	Total (0–150 cm)
Homes	64	351	628	1,043
Businesses	4	22	91	117
Roads (km)	6	12	23	41

Much of *Napier* has been built on land that rose out of the sea during the 1931 earthquake or has been reclaimed since that time. Nearly 8,000 homes are less than 150 centimetres above the spring high tide mark, and a considerable area of the city, including the airport, is less than 50 centimetres above the spring high tide mark.

Most of the city's low-lying areas are protected by the gravel banks along the beach on Marine Parade. These gravel banks are replenished mainly by sediment washed up north from the mouth of the Tukituki River. However, further north, the beach along Westshore has been eroding for some time.

Whakatāne is vulnerable to river flooding, and will become increasingly vulnerable to high seas. A large area of farmland to the west of Whakatāne and a part of the town centre lie less than 50 centimetres above the spring high tide mark. Much of the town and the surrounding areas are protected by stopbanks along the river, and water levels on the farmland are managed by pumping.

In *Tauranga*, there are many pockets of low-lying land around the harbour. Most of the low-lying homes are in Mount Maunganui and the suburbs of Otumoetai and Matua. Most of the low-lying businesses are near the airport. The harbour provides some protection from the full force of the sea.

In *Motueka*, about a third of the homes lie less than 150 centimetres above the spring high tide mark. A long sandbar currently protects the town from big waves during storms.

In *Nelson*, the industrial area around the port, the airport, and the suburbs of The Wood, Tahunanui, and Monaco are all low-lying. Minor ponding occurs in parts of the central city when king tides cause seawater to flow back up stormwater pipes. At times, waves crash over the seawall along Rocks Road.[59]

6.4 In conclusion

Accurate measurement of land elevation above sea level is an essential first step in considering the potential impacts of sea level rise. This is especially so for coastal flooding, which will be particularly visible and widespread.

The choice of which elevation contours to map is much more than a technical decision. How far ahead into the future should we look? Which of the IPCC scenarios should we use as a guide? How risk-averse should we be?

These elevation maps are only a first step. Assessment of the vulnerability of a particular area generally requires information about a range of local characteristics. These include the size and likelihood of storm surges hitting different parts of the coast. Storm surges ride on top of the sea, and so temporarily raise sea level.

Many of the cities and towns on New Zealand's coasts are located at river mouths. In such cases, sea level rise will exacerbate river floods by reducing the fall to the sea.

As discussed later in the report, elevation maps like those in this chapter provide a starting point for councils beginning to engage with their communities on this challenging issue.

Dealing with coastal hazards in New Zealand

As the climate changes and sea levels continue to rise, coastal hazards will also change. Not only will erosion speed up in places and become more widespread, coastal floods will become more frequent and extensive, and in places there will be groundwater problems.

There are seven sections in this chapter.

The first section looks back into the past and describes how the New Zealand government at both central and local level has dealt with erosion – the long-familiar coastal hazard.

Councils are required to plan for sea level rise.[60] The second section describes the direction and guidance provided to councils by central government.

The next four sections describe how councils have begun to plan for sea level rise, using examples from and near the four major coastal cities of Auckland, Wellington, Christchurch, and Dunedin. These examples illustrate problems with, and gaps in, the direction and guidance provided by central government.

The seventh section is a brief summary of the chapter.

7.1 Erosion – a long-familiar coastal hazard

The people of New Zealand have known about the dangers of living by the coast for a long time. Māori oral histories and traditions record the impacts from great waves, flooding, and erosion caused by storms.[61]

In the 19th century European settlement occurred along many parts of New Zealand's coast, particularly in places providing a safe port. Buildings, roads, and railways were constructed along the coast. In some places, large areas of land were reclaimed from the sea.

An early warning of the economic cost of coastal erosion occurred in 1879 when a storm knocked out part of a railway viaduct in Timaru.[62] In Oamaru in the 1930s, old locomotives were dumped on the beach to protect the railway yard from being washed away by the sea.[63]

Increasingly, seawalls were installed by public agencies and private landowners.

In the 1950s and 1960s, the Department of Lands and Survey actively encouraged sub-division of coastal property, without considering the impact on the landscape or coastal hazards.[64] In many places sand dunes were bulldozed.

In at least one case, the Department of Lands and Survey sold sections on Ohiwa Spit in the Bay of Plenty, where an entire town had been previously abandoned because of erosion. After several destructive storms in the 1960s and 1970s, the residents of Ohiwa Spit tried unsuccessfully to win compensation from the Government. The then Minister of Lands responded *"The principle is quite clearly 'caveat emptor' and I know of no fact which could establish any liability on the Crown"*.[65]

In contrast, compensation had earlier been paid to residents of Mokau who had lost their homes to the sea. The Department of Lands and Survey had subdivided this coastal area in Taranaki against the recommendation of the local council.[66]

By the 1970s erosion had become a major issue at many coastal settlements, especially in Northland, Coromandel and the Bay of Plenty. But erosion was not the only issue facing coastal settlements at this time. The loss of the natural character of the coast due to largely unconstrained development had become a major concern of the Government and the public. This was reflected in new policy and legislation.[67]

The concept of mapping parts of the coast considered more hazardous than others emerged at this time. Coastal survey programmes were established to collect data and methods for estimating coastal hazard zones developed.[68] The coastal hazard setback at a subdivision at Onaero Beach in Taranaki in 1978 may have been the first to be included in a district scheme.[69]

In the 1980s, councils began to restrict development using their powers under the Local Government Act 1974. Under s 641, councils could not grant building permits for sites subject to erosion or inundation by the sea, unless provision had been made for protection of the land. In 1981, an amendment allowed councils to grant permits for relocatable buildings in such areas.[70]

7.2 Sea level rise – amplifying coastal hazards

The passage of the Resource Management Act (RMA) in 1991 coincided with the growing recognition that sea level rise would increase coastal hazards.

In the previous year, the Intergovernmental Panel on Climate Change (IPCC) had published its first assessment which included projections of sea level rise. In 1992, New Zealand was one of 156 countries that signed up to the United Nations Framework Convention on Climate Change created at the Earth Summit in Rio de Janeiro.

In 1994, the first New Zealand Coastal Policy Statement (NZCPS) was published by the Minister of Conservation, as required under the RMA. This document directed councils to *"recognise the possibility of sea level rise"* in managing coastal hazards.[71]

In 2004, this was further reinforced in an amendment to the RMA that required councils to have *"particular regard to … the effects of climate change"*.[72] In the same year, the Ministry for the Environment (MfE) published guidance to assist councils in planning for sea level rise. This guidance was updated in 2008.

In 2010, the second NZCPS was published, and sea level rise was given much more prominence than in the earlier version.

Since then, there have been calls for more central government direction on sea level rise. The Ministry for the Environment began work on a national environmental standard in 2009. However, this work has now stopped. The Minister for the Environment's view is that there is *"too much uncertainty for a rigid standard to be applied"*.[73] The Ministry is now working on an update of its guidance document.[74]

Thus, current central government policy for planning for sea level rise is contained in two documents:

- The 2008 Ministry for the Environment Guidance Manual on Coastal Hazards and Climate Change
- The 2010 New Zealand Coastal Policy Statement.

2008 Ministry for the Environment Guidance Manual

This document provides two kinds of high level guidance, as well as a great deal of technical information.

The first kind of guidance is concerned with the amount of sea level rise that should be incorporated into planning decisions. It is recommended that a base amount of 50 centimetres from 1990 to 2100 be used, but that the consequences of an 80 centimetre rise (or more) be considered. Beyond 2100, an allowance of one centimetre each year is also recommended for planning purposes.

These sea level rise projections are taken from the IPCC's Fourth Assessment in 2007.[75]

Coastal hazards are to be assessed over *"a lengthy planning horizon such as 100 years"*.[76]

The second kind of guidance is expressed in terms of four general principles that councils should incorporate into their decision-making.

- A precautionary approach
- Progressive reduction of risk over time
- The importance of coastal margins
- An integrated, sustainable approach.

2010 New Zealand Coastal Policy Statement

The purpose of the NZCPS is to state policies in order to achieve sustainable management in relation to the coastal environment. Councils are required to follow the NZCPS when planning.[77]

This document begins with a list of seven coastal policy objectives. The fifth is concerned with coastal hazard risks which are to be managed taking account of climate change. There are three parts to the objective (slightly paraphrased).

- Locating new development away from areas prone to coastal hazards
- Considering responses, including managed retreat, for existing development prone to coastal hazards
- Protecting or restoring natural defences to coastal hazards.

The New Zealand Coastal Policy Statement requires councils to:

- Identify areas 'potentially' affected by coastal hazards over 100 years or more
- manage such areas using a 'precautionary' approach.

The New Zealand Coastal Policy Statement is largely focused on the protection of the natural coastal environment. It contains a preference for strategies that reduce the need for 'hard' protective structures like seawalls.

Around New Zealand, councils are responding to Government policy on sea level rise in various ways. The next four sections of this chapter explore some of the planning for sea level rise that has been undertaken in and near the four major cities featured in Chapter 3 and Chapter 6. The purpose is to illustrate some of the issues that have arisen.

7.3 Auckland and Coromandel

Erosion has long been a problem in places along Auckland's coasts.

An example is the southern end of Muriwai Beach on the west coast, which has been eroding since the 1960s. In just three years (2005 to 2007), several storms caused the shoreline to retreat around eight metres inland. Since then the council has decided to allow a section of the beach to move inland. Sand dunes have been built up and planted, and a car park and the surf club moved many metres inland.[78]

On the east coast, erosion is a problem at the developed beachside town of Orewa. The Auckland Council is currently piloting an approach to manage the beachfront by dividing it into different sections – some sections are being armoured with large boulders, and dunes are being planted to stabilise them in others. At the southern end of the beach, where there is a reserve, the shoreline is being left to move naturally.[79]

The decision to allow part of the shore at Muriwai to retreat and the mixed approach being taken at Orewa are examples of strategic thinking at a beach level. Strategies for whole coasts are being developed and used overseas. In the United Kingdom, Shoreline Management Plans for the entire coastline of England and Wales have been developed, specifying which areas are to be defended from the sea and which are not.[80] Auckland Council is aiming to develop similar plans for their coasts.[81]

Although the Coromandel Peninsula is part of the Waikato Region, it is often called 'Auckland's playground'. Holiday homes have proliferated along its beachfronts *"creating an extensive and growing urban footprint along the coast"*.[82]

The beauty and wildness of Coromandel's beaches is what has made them so appealing to holidaymakers. 'Hard' engineered protection changes the natural character of the coast and leads to the loss of beaches by preventing them from migrating inland. Moreover, defending one part of a coast can make other parts more vulnerable.

However, in some places the only way to protect homes and roads will be by building 'hard' defences. In the Coromandel's Mercury Bay, a mixed approach is being taken to dealing with areas affected by coastal erosion.

The question as to whether coastal defences are funded by councils or by those directly affected will need to be considered as erosion (and flooding) worsens.

In Whitianga, the district council and community board have agreed that owners should pay for the protection of their own properties. Homeowners at Cooks Beach have paid for a seawall to be built, whereas the extension of the seawall at Buffalo Beach has been funded by the council in order to protect a road and beachfront reserve.[83]

The Auckland Council has notified its first Unitary Plan and an independent panel is currently considering the concerns of thousands of submitters.

In its proposed plan, the Council distinguished between 'greenfield' areas and 'other' areas in considering the potential for coastal flooding.[84]

- *Greenfield* areas with an annual 1% chance (or more) of being flooded after two metres of sea level rise were deemed to be 'coastal inundation areas'.
- *Other* areas with an annual 1% chance (or more) of being flooded after one metre of sea level rise were deemed to be 'coastal inundation areas'.

The proposal in the plan is that *greenfield* coastal inundation areas would be out of bounds for development. However, new buildings can be constructed in other coastal inundation areas, provided floors are raised at least 50 centimetres.[85]

The Independent Hearings Panel questioned the need to plan for a two metre rise in sea level, and consequently the restriction on greenfield development.[86]

Distinguishing between greenfield development and development in other areas makes sense. In evidence presented to the hearings panel, a council planner rightly pointed out: *"Urban growth and subdivision of land creates a land use expectation for an indefinite future period"*.[87]

The 2008 Ministry for the Environment Guidance Manual does not provide specific advice on time frames (and amounts of sea level rise) to use in planning for different kinds of development.

The Auckland Council now proposes to replace reference to a two metre rise with *"broader references to 'long term'"*.[88] In essence, this leaves the problem with the Environment Court – developing policy through case law. Yet the judgements on two recent cases dealing with this issue are very different. Both judgements were consistent with the law; the inconsistency lies in the different ways in which coastal hazards were dealt with in the relevant council plans and policies.[89]

7.4 Wellington and Kapiti

Much of Wellington city's shoreline is protected by concrete seawalls and/or rock armouring.

Such hard defences will require increasingly expensive maintenance as the sea rises. The seawall at Paekakariki is soon to be replaced at a cost of $11 million.[90]

At Island Bay on the south coast, a large section of a seawall that had stood for decades was destroyed in the June 2013 storm. It too is soon to be repaired. A proposed longer term option was to move part of the road inland and allow the beach to expand and merge with a park. Wellington City Council is planning to develop a resilience strategy for the south coast.[91]

Such coastal strategies are essential to avoid costly *ad hoc* responses to increasing erosion and flooding. In particular, councils need clear direction on when they can make the 'hard call' to stop maintaining a coastal road or seawall.

Just north of Wellington city is the Kapiti Coast where the district council's planning for coastal erosion went awry. Some useful scientific and policy insights can be gleaned from examining what happened.

Some parts of the Kapiti shoreline are eroding and other parts are accreting. In August 2012, the Kapiti Coast District Council released a report on coastal erosion that included projections of where the shoreline could be in 50 and in 100 years' time.[92] These projections were used to create 'erosion hazard zones' that included 1,800 coastal properties along the Kapiti coast.[93] On the day the report was released, the Council sent letters to affected coastal property owners informing them that the 'erosion hazard zones' would now appear on Land Information Memorandum (LIM) reports.

Three months later, the Council notified the new Proposed District Plan, placing restrictions on building and subdivision within the 50 year hazard zone. In response a Waikanae couple, Mike and Veronica Weir, challenged the Council in the High Court. They were supported by Coastal Ratepayers United, a group of affected property owners.

In an interim judgement, the High Court found that while placing the erosion risk on LIMs was required by the law, the way in which it was done was inadequate and misleading.[94]

In April 2013, the Council appointed an independent scientific panel to review the methodology used in the assessment. In December 2013, the Council decided that the 'erosion hazard zones' would no longer appear on LIM reports.

In its June 2014 report, the independent panel concluded that the 2012 coastal erosion assessment was *"not sufficiently robust for incorporation into the Proposed District Plan"*.[95] The Council is no longer considering coastal erosion zones in its current review of the District Plan, but is planning further research.

The Kapiti experience is instructive in a number of ways.

Importantly, the process was hasty. On a single day, the report was released, the hazard zones were put on LIMs, and letters were sent to property owners. In his judgement, Justice Joe Williams commented that it *"would be a callous Council indeed that was unmindful of [the] potential impact"* on the value and marketability of coastal properties.[96]

Both the New Zealand Coastal Policy Statement and the MfE Guidance Manual require councils to take a 'precautionary approach' to planning for coastal hazards. In the Kapiti assessment of erosion hazard, 'precaution' was embedded into the scientific modelling in a number of places. This included double-counting part of the predicted sea level rise, and assuming accreting parts of the beach would not continue to accrete.[97]

Box 7.1 Putting hazard information on LIMs

Justice Joe Williams began his judgment on the Kapiti case thus:

"The site of this debate is the humble LIM: the local authority's land information memorandum familiar to every purchaser of property in New Zealand."

Local councils are required to provide up-to-date information on properties within their districts either by putting it on LIMs or by including it in a district plan.

The information must identify special features and characteristics of the land *"… including but not limited to potential erosion, avulsion, falling debris, subsidence, slippage, alluvion, or inundation, or likely presence of hazardous contaminants…"*.[98]

Councils could be found negligent if they hold relevant information and fail to provide it clearly, fairly, and accurately.[99]

7.5 Christchurch

Planning for sea level rise is currently a topic of debate in Christchurch. In July this year, information on coastal hazard risks was placed on the LIMs of nearly 18,000 properties in the city. With ten times the number of properties involved, this is the Kapiti situation writ large.

A year earlier, the Government had directed the Christchurch City Council to complete a new district plan by March 2016. This direction, made under the Canterbury Earthquake Recovery Act, specified a fast-tracked process that shortened consultation periods and allowed appeals only on points of law.[100]

When a district plan is developed, consideration of how natural hazards are to be managed and planned for is required. The Council commissioned a report to identify areas that will be vulnerable to coastal flooding and coastal erosion within the next 50 and 100 years.[101] This resulted in a series of maps that showed four hazard zones – 50 year and 100 year zones for flooding and for erosion.

The report was released on 3 July 2015, and on the same day the new information was placed on the LIMs of the affected properties. Public meetings were held by the Council to explain the information. Three weeks later, new rules restricting subdivision and development in these zones were notified.[102]

In response, as in Kapiti, some affected residents formed a group called Christchurch Coastal Residents United (CCRU). An important difference from the Kapiti situation is that some of the areas denoted as coastal hazard zones were badly damaged in the 2010 and 2011 earthquakes. It is not surprising that meetings organised by CCRU were attended by hundreds of people. Residents expressed concern that the process was rushed and lacked transparency, and that the Council's public meetings were held too late.[103]

At the end of September, the Government decided to remove coastal hazards from the fast-tracked process. At a joint press conference with Government Ministers, the Mayor of Christchurch stated:

"The fast-tracking of the District Plan Review was always intended to be about earthquake recovery. We do not need to move with the same speed with respect to these longer term issues".[104]

Currently, the Council is legally obliged to keep the hazard zone information on the LIMs of affected properties. However, the residents group has raised concerns about the coastal risk assessment used to identify the hazard zones.

"This assessment is considered to be based on speculative predictions which are overly precautionary and which do not look at what is likely to occur but instead take a worst case scenario viewpoint of what maybe is possible".[105]

As noted in the previous section, both the 2010 New Zealand Coastal Policy Statement and the 2008 MfE Guidance Manual require councils to take a precautionary approach.

As in the Kapiti situation, 'precaution' has been embedded into parts of the Christchurch coastal risk assessment. This is particularly notable in the identification of 100 year erosion hazard zones.

The New Zealand Coastal Policy Statement refers to protecting *existing* development *likely* to be affected by sea level rise and *new* development *potentially* affected by sea level rise. In the Christchurch coastal risk assessment, *likely* was interpreted to mean a chance of being affected by erosion of at least 66%, and *potentially* to mean a chance of being affected by erosion of at least 5%.[106]

The result is that a property estimated to have only a 5% chance of eroding in 100 years time is deemed to be within an erosion hazard zone.[107]

The modelling of future erosion relies on the Bruun Rule. This rule was first proposed in 1954. It applies to sandy beaches that are in a stable state – not actively accreting or eroding – and where there is little sediment movement along the shore. In other situations the Bruun Rule is only useful as a first approximation.[108]

The Brighton shoreline has been accreting since at least 1941 due to longshore currents carrying sediment from the Waimakariri and other North Canterbury rivers.[109] Although the Christchurch coastal risk assessment does add in an accretion component, the modelling projects a reversal of this long-term trend. Certainly, as the sea rises, accreting shores are likely to begin to erode, but there is great uncertainty about when this will happen in any particular case.[110]

Finally, when hazard information is put on a LIM, it must be clear. The wording that has been placed on the LIMs of properties in the 50 year flood hazard zone reads: *"This property is located in an area susceptible to coastal inundation (flooding by the sea) in a 1-in-50 year storm event"*.

What does this mean? It seems to say that the property is likely to be flooded once in the next fifty years.

But what it actually means is something much more complicated, namely that in the year 2065 (after 40 centimetres of sea level rise), there is at least a 2% chance that the property will be flooded. The chance that the property will be flooded now is significantly lower.

7.6 Dunedin

The part of Dunedin that is most at risk from sea level rise is the area of Harbourside and South City. Built on land reclaimed from the harbour, it is very low-lying and the water table is close to the surface in places.

This area is bound by the dunes that rise many metres above St Clair and St Kilda beaches, so a wall of sand currently protects the flat suburbs from southerly swells that pound the beaches. The flats have been flooded by high seas in the past. In the late nineteenth century, the sea flooded in through breaches in the sand dunes, caused at least in part by the Government mining the sand.[111]

St Clair Beach has a long history of erosion – the readily visible piles in the sand are remnants of failed groynes installed in the early 1900s.[112]

In June this year, large areas of these suburbs were swamped when heavy rainfall overwhelmed drains. The drainage system could not cope with both a high water table and little fall to the sea.

The water table in these suburbs has a 'tidal signal' – it rises and falls with the tides. The closer to the sea, the more marked this effect is. As the sea rises, it will lift the water table higher.

In 2014, the Dunedin City Council commissioned an assessment of a range of options for defending these suburbs from the effects of sea level rise.[113]

One option canvassed was to build an underground seawall, designed to stop seawater pushing up the groundwater from below. This was not recommended – not only would it be very expensive, it could not be guaranteed to work.

The other options all involve various dewatering schemes – pumping water out of the ground. The recommended option is to sink dewatering wells along the coastal fringes, including along the harbour. The effectiveness of such a scheme depends on the Middle Beach dune remaining intact. Also, dewatering can lead to ground slumping.[114]

The Council is continuing to investigate measures to protect these suburbs, but is also investigating non-protection measures – that is, forms of managed retreat.

However, how to go about managed retreat is far from clear. In its 2014 report on managing natural hazard risk, one of the research priorities identified by Local Government New Zealand was *"When does retreat become the most viable option and how can this be given effect to?"*

The situation in this part of Dunedin could become analogous to the red zoning in Christchurch after the 2011 earthquake, although over a longer time frame. Local Government New Zealand has raised the possibility of creating a fund similar to that of the Earthquake Commission (EQC).

"While the legal tools exist, it is difficult to see how it can be implemented effectively without some form of (probably nationally funded) financial assistance mechanism similar perhaps to an EQC fund that might operate before an event rather than after an event. Such a mechanism does not currently exist and its design and implementation would raise many vexed public policy issues".[115]

7.7 In conclusion

While central government has provided some direction and guidance, the responsibility for planning for the effects of a rising sea has largely been devolved to local and regional councils. The difficulty and complexity of this task is considerable and councils that have tackled it should be commended. However, when councils have acted they have sometimes been challenged by those affected.

Better direction and guidance is needed in three broad areas:

- Scientific assessment of the impact of a rising sea on coastal hazards
- The process of engaging with the community
- The planning and management decisions that follow.

Methodologies that are used in coastal risk assessments need to be fit-for-purpose and consistent, with assumptions clearly stated. Further, they need to be written in a way that can be readily understood, or else they will not be trusted.

Affected communities have expressed concerns about various aspects of the process that follows the undertaking of coastal risk assessments. One of these is the speed of the process; another is the lack of transparency.

The decisions being made by councils planning for sea level rise can be far-reaching and affect many people, so should be made carefully. Current policy is geared toward risk aversion – in some situations, this will be appropriate, in other situations not.

The concluding chapter contains eight recommendations from the Commissioner to the Government.

8 Conclusions and recommendations

The world must grapple with two aspects of climate change – mitigation and adaptation.

- Mitigation – reducing emissions of carbon dioxide and other greenhouse gases to slow down climate change.
- Adaptation – dealing with the consequences of climate change.

This report is about adaptation to one of the consequences – the rising level of the sea.

There is an urgency to mitigation – greenhouse gas emissions should be reduced as quickly as possible.

But this sense of urgency need not spill over into adaptation planning. During this investigation, it has become clear that there is some time to develop good policy and planning for sea level rise. Because so many will be affected, whether it be by flooding, erosion, or changes to groundwater, councils must engage with coastal communities in a measured and empathetic way. The focus should be on preparing well rather than rushing.

The level of the sea around New Zealand is rising and will continue to rise for the foreseeable future. This much is certain. What is uncertain is the rate of rise, especially later this century and beyond.

New Zealanders are familiar with the power of the sea. Living with risks of flooding and erosion are part and parcel of living near the coast. However, these risks are changing. As the sea rises, coastal floods will become more common, erosion will increase, and groundwater will rise.

There will be far-reaching impacts on coastal towns and cities. Mapping undertaken to support this investigation shows significant areas only a metre or so above today's spring high tide mark.

The actual impacts on such areas will vary from place to place. A range of local physical factors determine just how vulnerable a low-lying coastal area is to sea level rise. Thus, the maps of land elevation in this report are just that – they are not maps of hazard zones.

Both the uncertain rate of sea level rise and the range of local factors make anticipating the nature – and timing – of the impacts of a rising sea very difficult.

The sea is gradually but inexorably rising, and the risks therefore incrementally worsen. In a few places the effects are already tangible or are imminent, but in most places will unfold slowly over time.

Councils and communities across the country face the difficult task of assessing the risks and deciding what to do in response. Planning in the face of uncertainty is never easy, but is particularly difficult when choices will affect people's homes.

Coastal residents will bear the brunt of a rising sea, but did not cause it and were not warned of it before choosing where to live. Yet failing to inform those considering living on the coast is not an option.

So plan we must, and plan carefully. However, in all but a few situations, haste is not necessary or desirable. Councils need to take some time to develop strategies and make fair decisions that are based on assessments that are both robust and transparent.

Where should protective seawalls be built? Who will pay for them? Where should beaches be left to retreat inland? When is abandoning maintenance of a coastal road justified? And when does the retreat of a whole community become inevitable?

This chapter contains eight recommendations from the Commissioner to the Government. The first seven are aimed at improving the direction and guidance provided by central government to councils. The last is focused on the fiscal implications of sea level rise.

8.1 National direction and guidance

Currently, there are two central government documents – the 2010 New Zealand Coastal Policy Statement (NZCPS) and the 2008 MfE Guidance Manual – that provide direction and guidance to councils on how they should deal with sea level rise.

A number of problems with how councils are planning for sea level rise have emerged during this investigation – problems with science assessments, with the process of engaging with the community, and with the planning and management decisions that follow.

In seeking to improve central government direction and guidance, the question of the form it would best take arises. For instance, should the two documents simply be revised? Or should a National Policy Statement (NPS) on sea level rise be created, as some have suggested?

The New Zealand Coastal Policy Statement is the only NPS to be prepared by the Department of Conservation and signed by the Minister of Conservation. This came about because the natural character and beauty of the coast and access to the sea are greatly valued by New Zealanders, and seen to be of national importance.

However, because the NZCPS is largely focused on protecting the natural coastal environment, it does not address all the dimensions of sea level rise. Objective 5, which is concerned with the management of coastal hazard risks taking account of climate change, is just one of seven objectives. If Objective 5 were to be removed from the NZCPS, some of the policies would still need to refer to sea level rise. This is because sea level rise will affect ecosystems, natural character, and public access.

The Minister for the Environment has indicated an intent to add natural hazards to the list of national priorities in the RMA and to develop an NPS on natural hazards. Sea level rise could be included in such an NPS.

Whatever form it takes, direction and guidance needs to reflect the particular nature of sea level rise. It is incremental and relentless; it is outside human experience, so seems unreal.

The 2008 MfE Guidance Manual is soon to be revised, providing an opportunity to address matters that emerged during this investigation. The revised guidance should be a 'living document', so it can be readily updated.

Recommendation to the Minister for the Environment and the Minister of Conservation:

a. **Take direction on planning for sea level rise out of the New Zealand Coastal Policy Statement and put it into another National Policy Statement, such as that envisaged for dealing with natural hazards.**

b. **Direct officials to address the matters raised in this investigation in the revision of the 2008 MfE Guidance Manual.**

8.2 Measuring land elevation

Every centimetre of sea level rise will have an impact. Thus, measuring the elevation of coastal land above the sea as accurately as possible is essential for planning.

The technology for accurate measurement of elevation is LiDAR. Pulses of light from a laser on an aeroplane are bounced off the ground, and the time taken for the reflected pulse to return is used to measure the elevation of the ground.

Three councils have mapped their entire regions with LiDAR, and others have mapped selected parts. However, the mapping has been done with varying levels of accuracy and different baselines have been used.

The work commissioned from NIWA for this report standardised all the available data to a baseline or 'zero level' of MWHS-10 – the mean of the highest 10% of high tides.

Such national consistency is essential. There is no good reason for a 50 centimetre contour to mean one thing in one part of the country and something else in another. It also ensures that science assessments and planning decisions are comparable.

To attain national consistency, protocols for procurement of LiDAR data must be developed. Further, the elevation datasets should all be put into a national repository.

It is also important to map the elevation of floodplains where there is the potential for incoming tides to exacerbate river flooding.

Recommendation to the Minister for the Environment:

In revising central government direction and guidance on sea level rise, include protocols for the procurement of elevation data, and work with Land Information New Zealand and other relevant agencies to create a national repository for LiDAR elevation data.

8.3 Projections of sea level rise

In its latest report, the Intergovernmental Panel on Climate Change (IPCC) presented projections of sea level rise under four different scenarios of greenhouse gas emissions. Each projection is presented as a trajectory with a best estimate, a lower and an upper limit out to 2100. The projections are relatively consistent for several decades, but then increasingly diverge.

How should such projections of sea level rise be incorporated into direction and guidance for councils?

There are a number of aspects to this, including the following.

First, the base year must be clear. In its 2013 report, the IPCC averaged mean global sea levels between 1986 and 2005 for use as a baseline.

Second, adjustments may need to be made for particular regions or localities where the land is known to be rising or falling.

Third, the IPCC produces its reports every five or six years. A 'living' guidance manual could be quickly updated after each IPCC report.

Finally, the range in projections under different scenarios of sea level rise should be recognised in sensitivity analysis of coastal assessments.

Recommendation to the Minister for the Environment:

In revising central government direction and guidance on sea level rise, set standards for the use of IPCC projections of sea level rise to ensure they are used clearly and consistently across the country.

8.4 Time horizons – how far ahead to look?

The 2010 New Zealand Coastal Policy Statement set a time horizon for planning of at least 100 years. But what is needed is a variety of planning horizons which depend on the nature of the decisions to be made.

In practice, however, planning for sea level rise has become focused on 50 and 100 year time horizons.

The 2010 New Zealand Coastal Policy Statement has one policy that covers *'Subdivision, use, and development in areas of coastal hazard risk'*. Yet there is a big difference between subdivision of a quarter acre section in an urban area and subdivision of farmland to create a new suburb.

In the former case, 100 years seems excessive, given that the Building Act only requires a new building to have a life of 50 years.

In the latter case, 100 years seems too little, given that new suburbs are expected to exist into the indefinite future. New suburbs also require expensive infrastructure where the investment is only recouped over many decades.

Further, the current prominence given to 100 years can give the impression that the sea will stop rising then, which is extremely unlikely because of the inertia in the climate system. Centuries of 'committed sea level rise' almost certainly lie before us.

Recommendation to the Minister for the Environment:

In revising central government direction and guidance on sea level rise, specify planning horizons that are appropriate for different types of development.

8.5 Separating scientific assessment and decision-making

Both the 2008 MfE Guidance Manual and the 2010 New Zealand Coastal Policy Statement require a 'precautionary' approach to planning for sea level rise.

Taking a precautionary approach to making decisions concerned with protecting the environment has been made a requirement in a number of New Zealand laws and international agreements such as the Rio Declaration.

Sir Peter Gluckman has noted that the precautionary principle *"… has long been a target for confusion and controversy. … The problem is in the multiple and, at times, conflicting interpretations…"*.[116] Regardless of the various definitions that are used, the precautionary approach was originally intended to be used in protecting the natural environment, not the built environment.

During this investigation, it has become clear that precaution is being embedded into scientific assessments of coastal hazards, sometimes to an extreme extent. In the Kapiti situation, Justice Williams concluded that there was *"a good argument"* for describing the result of the coastal assessment as the *"very worst case scenario"*.[117]

Judgements, such as those involved in adding safety margins or setting restrictions on development, should be made transparently by decision-makers, not rolled into technical assessments.

The standard results of running a coastal hazard model should instead be probability distributions with most likely values and ranges of potential values expressed with a level of confidence.

Recommendation to the Minister for the Environment:

In revising central government direction and guidance on sea level rise, specify that 'best estimates' with uncertainty ranges for all parameters be used in technical assessments of coastal hazards.

8.6 Engaging with communities

The standard way in which councils deal with planning for natural hazards like earthquakes, land slips, and river floods is to first commission a technical report that identifies the properties at risk. Once the council has accepted the report, the hazard information is immediately put on the Land Information Memoranda (LIMs) of affected properties. Any regulations that restrict the use and development of the properties are notified at the same time or soon after.

It is difficult to believe the sea is rising because it is outside human experience. For many, receiving a letter advising of susceptibility to flooding or erosion will come as a shock. It is not surprising that a condensed process and a lack of transparency is meeting with community opposition and legal challenges.

What is needed is a much slower process that actively engages with affected communities *before* decisions are made. Sometimes difficult decisions will need to be made that will disadvantage some, but they must be made carefully and with empathy.

The first stage of such a process should be the gathering and provision of information, beginning with accurate maps of elevation in coastal areas. Where there are 'soft' shores, all historical aerial photographs that can be found should be provided.

In many situations there will be time to build and share understanding of the risks. Locals know their beaches well so there is value in including local knowledge into coastal assessments.

Coastal communities can also be involved in deciding what the trigger points for a change in management should be.[118] There is a need for openness to considering a range of options.

Clear communication is vital. One particular problem is the need for describing 'high waters' other than a 'one in a 20/50/100 year flood event'. Not only is this terminology difficult to understand, it is not a stable measure over time. As is shown in Chapter 3, a 'one in a 100 year flood event' will become a 'one in a 50 year flood event', then a 'one in a 20 year flood event', and so on.

The placing of hazard information on LIMs is required under s 44A of the Local Government Official Information and Meetings Act 1987. There is certainly a need for informing property buyers, but it should be done in a way that is fair and does not come as a complete surprise to coastal residents.

Recommendation to the Minister for the Environment:

In revising central government direction and guidance on sea level rise, include a standard process for council engagement with coastal communities.

8.7 Strategies for coastlines

Developing strategies for coastlines requires thinking far into the future, and will not be easy because of competing priorities.

In places around the country, seawalls are being built or strengthened, and beaches are being ‘armoured’ with banks of large rocks. While each of these hard defences may not cost a lot, collectively the costs will mount. A piecemeal reactive response will become increasingly expensive and, as the sea continues to rise, maintenance and replacement will be needed. At some point, most hard defences will be abandoned.

The cumulative cost of building and maintaining hard defences is one issue. Another is the loss of the natural character of the shoreline. Many settlements have grown up by the coast because of access to sandy beaches, *kai moana*, and the beauty and wildness of the coast. Preserving some natural shorelines – or rather allowing them to freely move slowly inland – is vital. For this reason, soft defences – replenishing and planting dunes – should be preferred wherever feasible.

It is encouraging to see strategic thinking for Auckland beaches like Orewa and Muriwai and the intention to extend such thinking to whole coastlines. Decisions about, for example, where to defend or when to retreat, need to be made strategically with consideration of costs and trade-offs. Current central government direction and guidance requires strategic planning for coastlines, but further guidance is needed on how to do it.

Without strategic planning, difficult negotiations over the funding of hard defences and coastal infrastructure lie ahead. How is the cost of a seawall to be split between a council and the community it will protect? When will a council be justified in ceasing to maintain a vulnerable coastal road?

The Shoreline Management Plans developed in the United Kingdom provide one model. In each plan, the shoreline is divided into units. Policies developed for the units include variations of ‘active defence’, ‘managed realignment’, and ‘no intervention’.

Strategies for coastlines must be able to deal with the uncertainty in the rate of sea level rise and the uncertainty in the impacts on different parts of the coast. In many places, an adaptive management approach will be needed. For this, monitoring of coastal parameters is vital for identifying when trigger points have been reached. Such monitoring is also required if we are to develop better models of erosion and accretion.

Recommendation to the Minister for the Environment:

In revising central government direction and guidance on sea level rise, specify that councils develop whole coast plans for dealing with sea level rise, and expand coastal monitoring systems to enable adaptive management

8.8 Fiscal risk associated with sea level rise

Continued sea level rise is not something that might happen – it is already happening, will accelerate, and will continue for the indefinite future. Unlike earthquakes and volcanic eruptions, it is foreseeable.

Adapting to sea level rise will be costly. Homes, businesses, and infrastructure worth billions of dollars have been built on low-lying land close to the coast.[119]

Some may argue that individuals should be allowed to make their own choices and bear the consequences. It may be possible to do this in some situations, but this should be done at no cost to the public.

There are also risks with council planning. Restrictions on development that are premature or overly precautionary will incur significant opportunity costs.

It is inevitable that both central and local government will begin to face pleas for increasing financial assistance. The highest costs will come from large scale managed retreat.

Both the 2008 MfE Guidance Manual and the 2010 NZCPS encourage managed retreat – moving homes and infrastructure to higher ground away from the coast – in preference to building bigger and bigger hard defences.

However, little thinking has been done on how to implement a managed retreat strategy. The critical factor is scale – with scale will come the uprooting of entire communities and the associated financial cost. But the alternative to managing an inevitable retreat will be leaving people living in homes that become uninsurable and then uninhabitable.

New Zealanders have an expectation that central government will provide financial assistance for those affected by natural disasters. Local Government New Zealand has suggested that a financial mechanism similar to the Earthquake Commission fund could be created to assist with managed retreat.

It is not too soon to consider the economic and fiscal risks of sea level rise, and include the forward liability into planning and investment decisions. This will require input from representatives of a range of interests – local government, coastal residents and landowners, the insurance and banking industries, and infrastructure providers.

Recommendation to the Minister of Finance:

Establish a working group to assess and prepare for the economic and fiscal implications of sea level rise.

Notes

[1] National Climate Change Adaptation Research Facility, 2013.

[2] United Kingdom Environment Agency, 2012, pp. 5, 34-35.

[3] The technical reports commissioned from NIWA are entitled: *'The effect of sea-level rise on the frequency of extreme sea levels in New Zealand.'* (NIWA, 2015a), and *'National and regional risk-exposure in low-lying coastal areas: Areal extent, population, buildings and infrastructure.'* (NIWA, 2015b). And from Dr John Hunter: '*Sea-Level Extremes at Four New Zealand Tide Gauge Locations And The Impact Of Future Sea-Level Rise'* (Hunter, 2015). Professor John Hannah at the University of Otago performed the initial standardisation of the tide guage data used in NIWA, 2015a and Hunter, 2015. A report detailing this standardisation also commissioned, entitled: *'The Derivation of New Zealand's Monthly and Annual Mean Sea Level Data Sets'* (Hannah, 2015).

[4] IPCC, 2013, Working Group 1, Chapter 13, pp.1181-1182. The four scenarios are RCP2.6, RCP4.5, RCP6.0, and RCP8.5. For simplicity, only the lowest (RCP2.6) and highest (RCP8.5) scenarios are shown in the figure. The projections of sea level rise under the middle two scenarios are very similar.

[5] Although the global mean sea level is generally rising, it does vary somewhat from year to year. Accordingly, the IPCC took the average of a 20 year period as its baseline in its 2013 report – the period from 1986 to 2005. This is why the projected sea level rises shown in Figure 2.1 are above zero in 2010.

[6] The sea level rise that will happen over the next several decades will occur largely as a result of past greenhouse gas emissions because of inertia in the climate system. IPCC, 2013, Working Group 1, Chapter 12, pp.1106-1107; IPCC, 2013, Working Group 1, Chapter 13, p.1143.

[7] *"New Zealand: Offshore regional sea level rise may be up to 10% more than global SLR."* IPCC, 2014, Working Group 2, Chapter 25, p.1381; Hannah and Bell, 2012, para.32.

[8] *"Based on current understanding, only the collapse of marine-based sectors of the Antarctic ice sheet, if initiated, could cause global mean sea level to rise substantially above the likely range during the 21st century. However, there is medium confidence that this additional contribution would not exceed several tenths of a meter of sea level rise during the 21st century."* IPCC, 2013, Working Group 1, Summary for Policymakers, p.25.

[9] IPCC, 2013, Working Group 1, Chapter 13, p.1140.

[10] Bell *et al.*, 2000, p.7; NIWA website, Coastal storm inundation.

[11] NIWA, 2015b, p.31. The El Niño Southern Oscillation can raise or lower the level of the sea around New Zealand by as much as 12 centimetres. The Interdecadal Pacific Oscillation can raise or lower the level of the sea around New Zealand by as much as 5 centimetres.

[12] A 7% increase in moisture in the atmosphere for every degree Celsius of warming is derived directly from the Clausius-Clapeyron equation. For more information, see IPCC, 2013, Working Group 1, Chapter 3, p.269.

[13] IPCC, 2014, Working Group 2, Chapter 25, p.1380. The IPCC has made this projection with a 'medium' level of confidence. Changes in rainfall are expected to be more pronounced in winter. See also Reisinger *et al.*, 2010, p.34.

[14] IPCC, 2014, Working Group 2, Chapter 25, p.1380. The IPCC states with a 'medium' level of confidence that most regions of Australasia are likely to experience an increase in: *"the intensity of rare daily rainfall extremes … and in short duration (sub-daily) extremes"*.

[15] Changes in rainfall will also affect the amount of sediment washed down rivers. This will change the amount of sediment carried by longshore currents and, in turn, affect erosion and accretion along coastlines (see Chapter 4). In some coastal areas, the water table will be pushed upward by the rising sea, increasing the risk of flooding from heavy rainfall (see Chapter 5).

[16] IPCC, 2014, Working Group 2, Chapter 25, p.1381. The IPCC has made this projection with a 'medium' level of confidence.

[17] McGlone *et al.*, 2010, p.89.

[18] IPCC, 2014, Working Group 2, Chapter 25, p.1381. The IPCC has made this projection with a 'medium' level of confidence.

[19] The vulnerability factors described in this chapter and the next are physical in nature. Vulnerability in the context of climate change adaptation is defined in various ways, including the scale of exposure, sensitivity, and the ability of communities to adapt.

[20] In 1938, a storm surge funnelled by the Firth of Thames caused tidal bores to rush up rivers. The storm surge and the accompanying heavy rainfall led to water overtopping the stopbanks resulting in flooding of at least 8,000 hectares of the Hauraki Plains. Dryson, 1938; Ray and Palmer, 1993, p.496.

[21] NIWA, 2013, p.34.

[22] Hunter, 2015; NIWA, 2015a. Such modelling is complex and sensitive to assumptions, for example, the choice of probability distributions. The results from both analyses were similar, though the methodologies differed somewhat. For simplicity, only the results from Hunter, 2015 are presented in this chapter. Both technical reports are available at **www.pce.parliament.nz**.

[23] The dataset has been corrected for shifts in the location of the tide gauges and tectonic changes in the height of the chart datum at each port (Hannah, 2015).

[24] On *23 January 2011 in Auckland*, a very high tide coincided with a very large storm surge of 41 centimetres. Homes, businesses and roads, including two motorways, were flooded, and stormwater systems backed up. On *21 June 2013 in Wellington*, a very strong southerly swept over the country, with heavy rain and swells of up to 10 metres reported in Cook Strait. Parts of the seawalls at Petone and Island Bay were smashed, and logs and driftwood scattered along Marine Parade and The Esplanade (NIWA, 2015a, Appendix A).

[25] The modelling results were provided with 68% confidence intervals that increasingly widen as the sea rises. How fast the sea will rise also becomes increasingly uncertain through time, as shown in Figure 2.1.

[26] In the modelling, the high water levels in these '100 year events' are higher than the highest levels on record by:

- 3 centimetres in Auckland
- 9 centimetres in Wellington
- 16 centimetres in Christchurch
- 11 centimetres in Dunedin

[27] The average of the midpoints of the four IPCC scenarios for global mean sea level rise projections from 2015 to 2065 is about 26 centimetres. The additional 10% rise projected by the IPCC for New Zealand gives a figure of about 28.6 centimetres. This has been rounded to one significant figure giving a value of 30 centimetres.

[28] The results from the NIWA modelling showed the same pattern. See NIWA, 2015a, p.32.

[29] This cannot be seen in Figure 3.3 because only increases in sea level up to 45 cm are shown.

[30] Most gravel beaches are 'reflective', meaning they are relatively steep, with waves surging up the shore rather than forming the classic breakers associated with wide, sandy 'dissipative' beaches. When gravel beaches erode, the gravel tends to migrate along the shore laterally rather than being carried out to sea (Hawkes Bay Regional Council, 2005, chapter 5, p.3.).

[31] Northland Regional Council, 2007, p.109; Thames Coromandel District Council website, The costs of protecting our coastlines.

[32] Hart *et al.*, 2008.

[33] Olson, 2010, p.123.

[34] Hastings District Council, 2013, p.10.

[35] Forsyth, 2009, p.1.

[36] Ingham *et al.*, 2006.

[37] The water table is the boundary between groundwater and the dry earth above it. It can be thought of as the upper surface of the groundwater.

[38] *"The water table lies close to the surface, typically 0.3 m to 0.7 m under the urban area."* (Rekker, 2012, p.ii.).

[39] *"It has been suggested that … every 0.1 m rise in sea level will result in an additional 0.09 m rise in ground water level over and above the rise in sea level itself."* (BECA, 2014, p.3.). See also Rekker, 2012.

[40] *"Liquefaction is an existing hazard in the Wellington region that may be exacerbated in some areas by higher groundwater levels resulting from sea level rise."* (Tonkin and Taylor, 2013, pp.8-9.).

[41] *"The [model] predicts that the sustainable yield from the Waiwhetu Aquifer will decline as sea level rises. … a 15% reduction in yield for a 0.75m sea level rise, and a 31% reduction for a 1.5m sea level rise."* (Gyopari, 2014, p.3.).

[42] IPCC, 2014, Working Group 2, Chapter 29, p.1623.

[43] NIWA, 2015b. The RiskScape GIS database was developed by NIWA and GNS Science to assist with the management of natural hazards.

[44] NIWA, 2015b, pp.10-12, 39-51.

[45] LiDAR elevation data is available for the entire Auckland, Bay of Plenty, and Wellington regions. In other regions, LiDAR data is available for some areas. In general, where LiDAR was available it was included in NIWA, 2015b.

[46] Councils have collected LiDAR data using different baselines. There are a number of definitions of Mean High Water Springs (MHWS). The definition used in the NIWA report is MHWS-10. This level is exceeded by 10% of high tides.

[47] Maps typically show coastlines at 'mean sea level' – the level halfway between high and low tides. The vertical difference in high and low tides around New Zealand varies considerably – it is less than 2 metres in Wellington and greater than 3.5 metres on the west coast of Auckland (Land Information New Zealand website, Tides around New Zealand).

[48] The RiskScape results shown in the tables in this chapter are for the entire urban areas of the four cities, but the accompanying maps have been necessarily truncated. The four maps have all been drawn to the same scale.

[49] The data in this table is for the Auckland urban area as defined by Statistics New Zealand. It extends as far north as Orewa, west beyond Massey and Henderson, and as far south as Papakura. It does not include some areas within the region with low-lying land such as Waiheke Island and Helensville.

[50] Blackett *et al.*, 2010.

[51] Auckland International Airport, 2006, p.17.

[52] The data in this table is for the Wellington urban area as defined by Statistics New Zealand – Wellington City, Porirua, Lower Hutt, and Upper Hutt.

[53] Pers. comm., Hutt City Council, 28 April 2015.

[54] KiwiRail media release, 24 June 2013, *'24 hour a day effort by KiwiRail to repair storm damage'*.

[55] Hughes *et al.*, 2015.

[56] Dunedin City Council website, St Clair Seawall Updates.

[57] Otago Regional Council, 2013, p.47.

[58] A further 30 urban areas collectively have over 5,000 homes that are less than 150 centimetres above the spring high tide mark.

[59] See Nelson Mail, 14 August 2010, *'Stormy waves force road closure' and Nelson Mail, 6 March 2015, 'Roads re-open after wild weather'*.

[60] Refer to the New Zealand Coastal Policy Statement 2010, prepared pursuant to the Resource Management Act (RMA) 1991. See also ss 7(i), 30, and 31 of the RMA 1991.

[61] King and Goff, 2006, p.13.

[62] Extract from the Report of the Railway Commission, Appendix to the Journals of the House of Representatives, 1880 Session 1, E-03, from question 3485.

[63] Otago Daily Times, 18 February 2009, *'Offers sought for remains of locomotive'*.

[64] See Peart, 2009, Chapters 11 and 12 for a history of coastal management in New Zealand.

[65] Hon. Duncan MacIntyre, Minister of Lands and Minister in Charge of the Valuation Department letter to Hon. P.B. Allan, 30 June 1972. See also Richmond *et al.*, 1984, p.470, and Memo from the Secretary of Transport to the Minister of Transport, 29 January 1976.

[66] Blackett et al., 2010.

[67] In 1974, New Zealand's first national coastal policy included: *"Recognition that the stability of a large proportion of the coastal land depends on the efficiency of sand dune fixation …"*. Minister of Works and Development, 1974. New legislation required regional and district schemes to recognise and provide for the preservation of the natural character of the coast and its protection from *"unnecessary subdivision and development"*. Town and Country Planning Amendment Act 1973, s 2.

[68] Hume *et al.*, 1992, pp.8-9.

[69] Taranaki Regional Council, 2009, p.24.

[70] Local Government Act 1974, ss 641 and 641A. Both sections were repealed by the Building Act 1991. The equivalent sections in today's Building Act 2004 are contained in ss 71-74.

[71] RMA 1991, ss 28, 62, 67, and 75; NZCPS 1994, Policy 3.4.2.

[72] RMA 1991, s 7(i).

[73] Local Government and Environment Select Committee, July 2015. 2015/16 Estimates for Vote Environment, p.5.

[74] In New Zealand, much environmental management is devolved to councils. There are two 'RMA instruments' that the Government can use when consistent environmental management across the country is sought. National Policy Statements (NPSs) are used to prescribe objectives and policies that must be 'given effect' in council plans. National Environmental Standards (NESs) are regulations that prescribe technical standards and methods. The New Zealand Coastal Policy Statement is an NPS.

[75] Note that these projections are not directly comparable with those in section 2.1 in this report. Not only do the scenarios in the Fourth Assessment differ from those in the Fifth Assessment, but the 20 year baseline period is 1980 to 1999 instead of 1986 to 2005.

[76] Ministry for the Environment, 2008, p.67.

[77] The RMA requires councils to give effect to the NZCPS in policy statements and plans and have regard to it in decisions on resource consents. For a summary of the requirements of the RMA in relation to the New Zealand Coastal Policy Statement, see New Zealand Coastal Policy Statement, p.7.

[78] Carpenter and Klinac, 2015.

[79] Auckland Council is developing Coastal Compartment Management plans, the beginnings of a strategy for managing the coast. See, for example, Orewa Beach Esplanade Enhancement Programme 2014 Revision.

[80] There are 22 Shoreline Management Plans in place for England and Wales. These can be found on the United Kingdom Environment Agency website. Each plan breaks the coast down into a number of smaller 'policy units'. Within each unit, decisions are taken about whether the coast will be defended or not over the short, medium and long term. Active defensive policies include 'advancing the line', where defences are built further seaward than the current shoreline to reclaim land, or 'holding the line' where existing defences are upgraded or maintained. However, due to the costs involved in active defence, policies such as 'managed realignment' or 'no active intervention' are becoming more common. A policy of 'managed realignment' allows the shoreline to move, but under relatively controlled circumstances, whereas a 'no active intervention' policy effectively signals a need to retreat from the coast.

[81] Pers. comm., Auckland Council, 3 November 2015.

[82] Peart, 2009, p.95.

[83] Pers. comm., Thames-Coromandel District Council, 27 October 2015; Thames-Coromandel District Council website, Coastal Management Areas – Mercury Bay.

[84] The Proposed Auckland Unitary Plan, 2013. Natural Hazards and Regional and District Objectives and Policies 5.12, policies 14-16. The plan defines 'greenfield' as 'land identified for future urban development that has not been previously developed'. The Proposed Unitary Plan, 2013, Part 4 Definititions.

[85] The Proposed Auckland Unitary Plan, 2013. Regional and District Rules 4.11, Natural Hazards, and Regional and District Objectives and Policies, 5.12.

[86] Independent Hearings Panel, 2015. Interim Guidance Text for Topic 022 Natural Hazards and Flooding. The provisions are being finalised through mediation.

[87] Statement of Primary Evidence of Larissa Blair Clark, 14 March 2015, p.54.

[88] Memorandum of Counsel for Auckland Council, 12 June, 2015, p.4.

[89] *Mahanga E Tu Incorporated v Hawkes Bay Regional Council* [2014] NZEnvC 83 and *Gallagher v Tasman District Council* [2014] NZEnvC 245. The first case was concerned with an application to build houses on coastal land prone to erosion in Mahia, Hawke's Bay. The Court approved the application subject to certain conditions, including the houses being built so they were relocatable and a bond being provided to cover the cost of removal. The second case was concerned with an appeal by a landowner against a change the Council proposed to its plan, which would have prohibited further subdivision on land in Ruby Bay, Mapua, at risk to coastal hazards. The Court declined the application despite the landowner proposing to mitigate the risk by building relocatable houses on elevated building platforms.

[90] Kapiti Coast District Council website, Paekakariki seawall upgrade gets green light.

[91] Wellington City Council website, Island Bay Seawall Project; Wellington City Council, Environment Committee Minutes, 16 December 2014.

[92] CSL, 2012.

[93] Up to 1,000 properties were in the 50 year zone and 1,800 properties were in the 100 year zone (Kapiti Coast District Council, September 2012 presentation. Coastal hazards on the Kapiti Coast).

[94] *Weir v Kapiti Coast District Council* [2013] NZHC 3522.

[95] Carley *et al.*, 2014, p.53.

[96] *Weir v Kapiti Coast District Council* [2013] NZHC 3522.

[97] *"A range of other factors (precautionary measures used in data processing) serve to increase the overall safety margin."* (CSL, 2012, p.19). In the report, CSL noted that the general precautionary approach may have resulted in some hazard distances being *"overly cautious"* (p.63), and that other factors need to be considered when the results of a scientific assessment are converted into management zones (p.65).

[98] Local Government Official Information and Meetings Act 1987- s 44A(2)(a). For those mystified by the language in this section, 'avulsion' is the sudden removal of land by the change in a river's course or by flooding to another person's land, and 'alluvion' is the deposit of earth, sand etc., left during a flood.

[99] See, for example, *Marlborough District Council v Altimarloch Joint Venture Ltd and Ors* [2012] NZSC at para. 234. In this case, the Supreme Court considered the Marlborough District Council had breached its duty of care as the LIM contained misstatements. The Court found the Council liable for losses to a purchaser who relied on the accuracy of the contents of a negligently prepared LIM.

[100] Canterbury Earthquake (Christchurch Replacement District Plan) Order 2014, cls 6 and 19. Under the normal RMA process, submitters unhappy with decisions made by a council can appeal to the Environment Court. The Court then undertakes a full review of the evidence – the science as well as the law.

[101] Tonkin and Taylor, 2015.

[102] Proposed Christchurch Replacement District Plan, Christchurch City Council. Rule 5.11.4.

[103] Pers. comm., CCRU, 2 November 2015.

[104] The Press, 29 September 2015, *'Controversial coastal hazards zonings dropped'*; Hon Gerry Brownlee, Hon Nick Smith, Hon Nicky Wagner, media release, 29 September, 2015, *'Coastal hazard issue to be uncoupled from fast-track Earthquake Recovery Plan process'*.

[105] Christchurch Coastal Residents United, Proposed Christchurch Replacement District Plan – Stage 3 Submission Form.

[106] NZCPS 2010, Policies 25 and 27; Tonkin and Taylor, 2015, p.42.

[107] Since all the properties in the 100 year erosion zone are also in the 100 year flood zone, some might ask why this matters. It matters because of what seems to be becoming standard practice in coastal risk assessments – quantifying 'potentially' with a subjectively chosen number and thereby embedding 'precaution' into the assessment.

[108] *"Approaches that adopt the Bruun Rule will be conservative and should be considered a first order approach, even within the probabilistic framework outlined above"* (Ramsay et al., 2012, p.73.). The probabilistic framework referred to was used in Tonkin and Taylor, 2015.

[109] About 14 cm of sea level rise has occurred in Christchurch over the last 70 years (Ministry for the Environment and Statistics New Zealand, 2015, Figure 39).

[110] With enough excess sediment, beaches can continue to accrete despite a rising sea. Whether or not the Christchurch beaches will continue to accrete into the future depends on the interaction between many factors, including sediment supply, future sea level rise, and any changes in wave strength and direction. One study of beach behaviour that included sediment budgets predicted that the Christchurch beaches were likely to continue to accrete with 50 cm of sea level rise (Hicks, 1993). In comparison, the modelling exercises carried out to support planning in Christchurch have predicted that the beaches will all switch to significant erosion over the next 50 years. These predictions should be thought of as 'highly precautionary.'

[111] The Dunedin Amenities Society, 16 July 2015, *'Armed for the Fray, The Mining of St Kilda'*.

[112] Otago Daily Times, 11 October 2015, *'Groynes buffeted by failure, opposition'*.

[113] BECA, 2014.

[114] Dunedin City Council, Report to Planning and Regulatory Committee, Climate change adaptation – Harbourside and South City Update, 24 July 2014.

[115] Local Government New Zealand, 2014, pp.43, 57.

[116] 2015 RMLA Salmon Lecture, Sir Peter Gluckman, p.5.

[117] *Weir v Kapiti Coast District Council* [2013] NZHC 3522, at para 71.

[118] See, for instance, Barnett *et al.*, 2014.

[119] The RiskScape analysis in NIWA, 2015b shows that the replacement value of buildings within 50 centimetres of the spring high tide mark is $3 billion and that of buildings within 150 centimetres of the spring high tide mark is $20 billion.

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