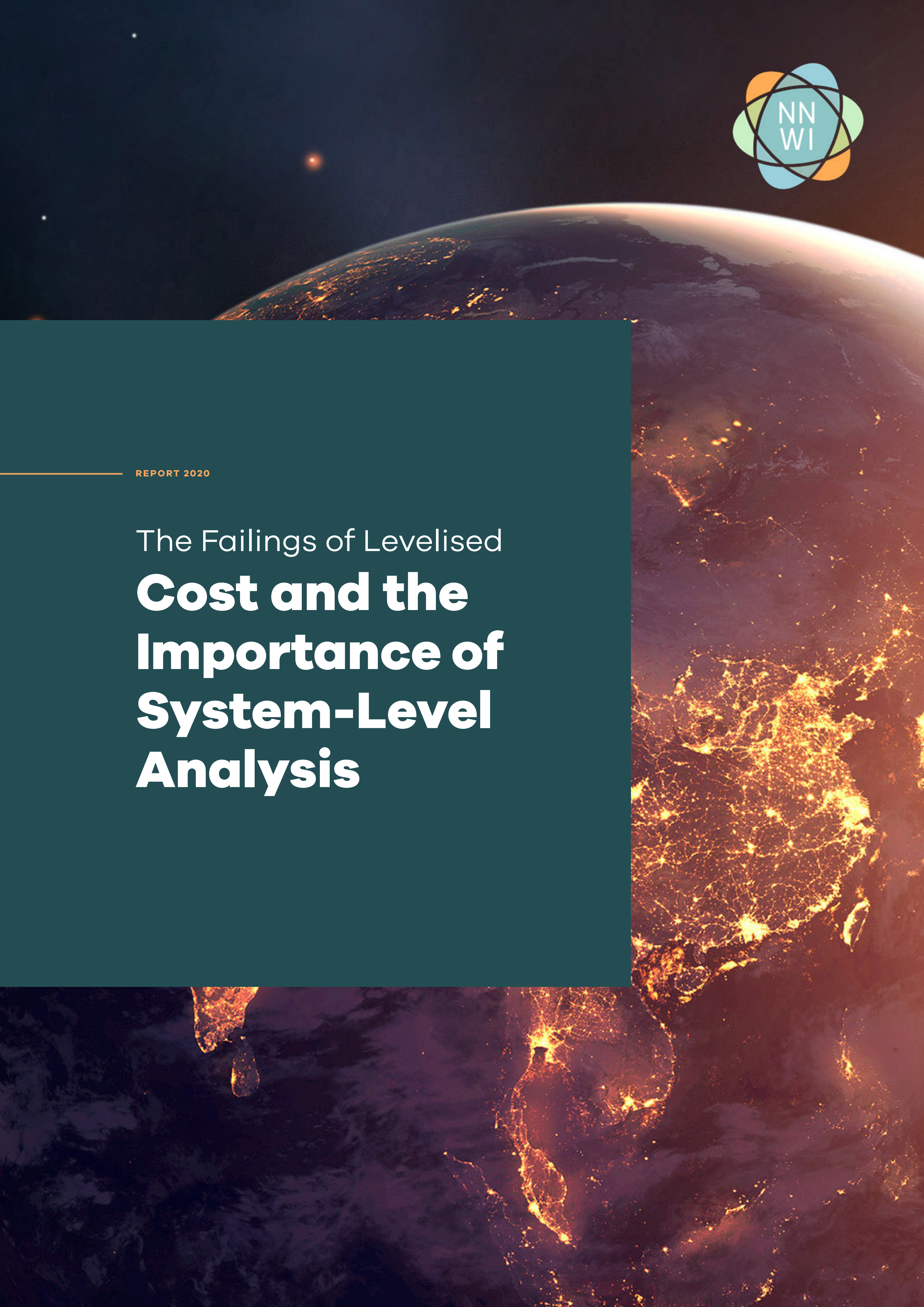


REPORT 2020

The Failings of Levelised **Cost and the Importance of System-Level Analysis**

Executive Summary

The current debate on the future of the electricity sector can be broadly defined by both unity and discord; it is unified on the urgent need to decarbonise power generation in light of the 2015 Paris Agreement, and divided on the means by which it can best be achieved.

On the issue of the future composition of the electricity system, the division is notably acrimonious – the eager promotion of particular generation technologies is tied to vociferous calls to exclude others, often nuclear power. The principal means by which casews are argued relies upon producing estimates of the levelised cost of electricity (LCOE) that purport to demonstrate the superiority of one generation technology to another by virtue of lower generating costs. Unsurprisingly, a wide variety of contradictory LCOEs have been produced by different advocacy groups that often reflect more than a glimmer of vested interest. As a result, no one is left any the wiser.

However, there is a further criticism of a higher order to be made of the levelised cost method beyond the dubious motivations of some of its practitioners. Namely, that it offers an exceedingly narrow lens through which to assess the relative merits of different generation technologies. The LCOE, a financial metric in essence tells us the average price per unit of generation required if an operator is to balance their revenue and their costs. This project-level focus is unable to capture a number of meaningful variables, including whether or not generation is regulated by the operator or by ambient weather conditions, the relationships between technologies of different types and the consequences that they might have for the system as a whole, and the broader impact of use of the particular technology on society, the environment, and the economy.

This report makes clear the importance of considering the value offered by different generation technologies in a holistic manner – to evaluate their system value – and illustrates the misconceptions that arise from use of the project-level, levelised cost method. Based on data from Europe and the United States, the report also provides a number of novel research findings:

1. The annual change in the share of total generation accounted for by nuclear power has the largest (negative) impact on system carbon intensity – ahead of other low-carbon technologies such as hydropower and variable renewable energies. On a per-MW of installed capacity basis, nuclear power is associated with a 34% greater reduction in the carbon intensity of a power system than renewable energies.

2. There exists a notable benefit of natural gas in terms of reducing system carbon intensity at low shares of variable renewable energies as the dominant motivation for expanding its use it to facilitate coal-for-gas switching, but the effect is notably reduced at higher levels of intermittent renewables as gas becomes increasingly entrenched as it is required to balance the electricity grid in times of low renewable generation.

3. The expansion of intermittent renewable technologies is associated with a concurrent decrease in the capacity factor of the system as a whole, which has implications for the generation cost of the residual load as well as electricity price volatility.

01 Introduction

The central aim of the 2015 Paris Agreement, to limit the global temperature rise to well below 2 degrees Celsius above pre-industrial levels, made clear the urgent need to deliver widespread decarbonisation across the world.

Thus far, the principal focus of climate policy has been the electricity sector due to the availability of existing low-carbon generation technologies and the high likelihood that the eventual decarbonisation of other sectors, such as heating, industry, and transport, will depend in no small part on their greater electrification and thus necessitate a further expansion of emission-free electricity supply. Indeed, the Intergovernmental Panel on Climate Change (IPPC) has stated that the almost complete decarbonisation of the power sector by mid-century will be required to achieve the targets of the Paris Agreement[1].

It is an inescapable fact that a successful transition to a decarbonised electricity sector will depend on whether or not its delivery can be accomplished in a cost-effective manner that does not compromise on the primary function of modern power systems: to supply consumers and industry with electricity in an economic way that provides acceptable reliability and quality. Despite a general consensus on the need to eradicate power sector emissions, there is little agreement on the precise manner in which it should proceed – views differ on the specific configuration of electricity generation technologies that should be encouraged and pursued, with widely varying emphasis placed on different low-carbon electricity sources and related infrastructures.

This state of affairs partially reflects an innocuous truism, that the optimal course of action in one area will not necessarily be as effective (or even feasible) in another – as always, context matters. This is most appreciable in the case of renewable energy sources whose productive expansion is contingent upon the local availability of the underlying resource, whether it be the sun, the wind, or water. Costa Rica, for example, is able to produce almost all of its electricity using low-carbon hydropower (82% in 2018, according to the International Energy Agency[2]) but this is not a power sector decarbonisation pathway that is available to most countries. The direct manner in which indigenous energy reserves affect thinking about national energy security will also lead to differences in power sector strategy more broadly.

A larger source of disagreement about the way in which power sector decarbonisation is best achieved stems from the increasing use of the levelised cost metric as the sole lens through which alternative electricity generation options are assessed and, more importantly, compared. The levelised cost of electricity is the average cost of producing a unit of electricity during the lifetime of a given power plant and can be also thought of the average revenue per unit of electricity generated required for the owner or operator of the generating facility to recover all their costs over an assumed financial life[3]. This suggests two productive – and appropriate – uses for levelised cost figures: by investors or utility companies in assessing the economics of an individual generation project (for use in negotiating a contracted output price, for example) or for evaluating the evolution (and potential trend) of the cost performance of a specific technology across time.

[1] https://www.ipcc.ch/site/assets/uploads/sites/2/2019/02/SR15_Chapter2_Low_Res.pdf
[2] https://www.iea.org/countries/costa-rica
[3] https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

However, there has been a marked generalisation in the use of the levelised cost method in much media discourse – the LCOE estimate has become the go-to means by which the relative merit of different electricity generation technologies are compared – which has led to a number of misconceptions about precisely what notion of value it captures.

It is clear that the levelised cost metric is a valid means of comparing the relative merits of different electricity generation technologies from the perspective of a potential investor or operator but the same cannot be said of its use as a means by which to evaluate the value of different technologies from the point of view of an electricity system as a whole. The conflation of these two viewpoints – implicitly contained in the use of the levelised cost method, suitable for project-level evaluation, as a measurement of system-level value – neglects the central fact of modern electricity sectors, namely that they are complex systems in which interactions between different electricity technologies have significant effects on the operation of the system as a whole. These interactions are not captured by the levelised cost method and so the system value of a given generation technology must be evaluated using different methods.

With particular reference to the nuclear industry, it should also be made clear the extent to which the levelised cost method has been weaponised against it – the common refrain is that the levelised cost of renewable energies has fallen to that extent that the expansion of nuclear power is no longer economic or necessary, decarbonisation can be better achieved by other means. Herein, the simplicity of the levelised cost method is an advantage as conceptualising system-level impacts is an inherently more complicated undertaking. Moreover, that the levelised cost figures often used are based on subjective assumptions is of course important and highlights another weakness of the methodology but the more insidious consequence of this development is to reduce debate on power sector policy to the irreconcilable technological zealotry of competing advocacy groups. A system-level perspective on decarbonisation makes clear the varied benefits of different generation technologies and that successful decarbonisation will depend on a diversified electricity base, with nuclear power operating alongside other low-carbon sources of electricity.

02 The Drawbacks of Levelised Cost

The popularity of the levelised cost of electricity (LCOE) metric lies in its simplicity, the financial performance of a power generation project can be summarised in a single figure and then communicated in a straightforward manner. This is of clear value to investors and utility companies in assessing the likely profitability of a particular generation project and provides a concrete starting block upon which to start to negotiate output contract prices, if applicable in a given electricity market.

A large number of cost variables are associated with the generation of electricity and the levelised cost method allows for their integration into a convenient per-megawatt-hour cost. Herein lies the potential misuse of use of LCOE figures as a means by which to compare the different cost of different technologies. The effectiveness of the method in producing a single figure and the ease with which that figure can be reported obscures the inputs that went in to producing it – if all the components of cost can be summarised with one figure then attention to the inputs and the significant ways in which they may be categorically different and so not directly comparable tends to diminish.

Indeed, the use of a single cost estimate as a basis for comparison in much media discourse leads to a natural assumption that the only significant point of difference between technologies is their levelised cost. However, this is evidently not the case, the importance of the distinction between intermittent and dispatchable power generation, for instance, is widely understood and yet is not captured in LCOEs. Despite this, LCOE figures are often presented with neither a wider context nor with a thorough qualification on what conclusions can (or ought to) be reached from them. As a result, the frequent conclusion that the generation technology with the lower levelised cost is the preferable option is unsurprising.

Thus, there can be seen to be two grounds on which to criticise the use of the levelised cost method and the LCOE figures that it generates: firstly, on an internal basis with reference to the various parameter assumptions that are implicit in its calculations and that are not often made clear; and, secondly, on an external basis with reference to the broad range of important considerations that are not reflected by it that fundamentally question the value of its use as a means to directly compare different electricity generation technologies.

A. Internal – What is Included?

The levelised cost method measures the lifetime costs of generating electricity using a particular technology and divides them by the total electricity produced by the technology, providing in the electricity price required to ensure that discounted costs equal discounted revenues and so yielding a project return on capital that equals the cost of capital (the discount rate). A simplified version of the calculation is provided by the United States Department of Energy:

$$\frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

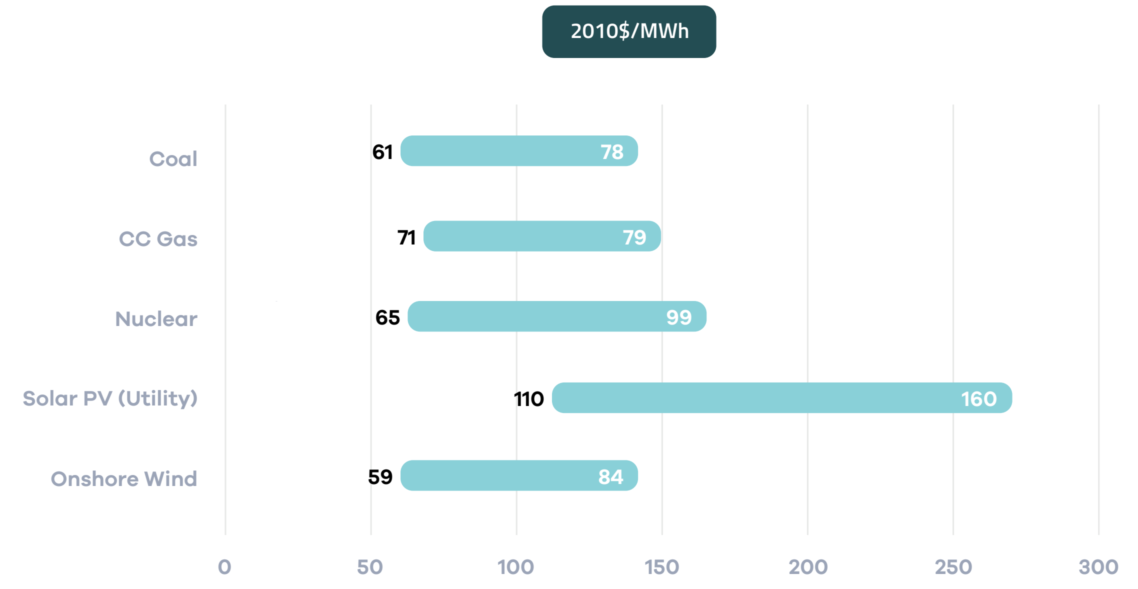
in which I_t represents the investment cost (including the financing costs) in year t, M_t the maintenance and operation (or variable) costs (potentially including a cost of carbon emission depending on the technology and jurisdiction), F_t the fuel cost, E_t the amount of electricity generated (measured in megawatt hours), r the discount rate (or cost of capital), and n the number of time periods for which the project will last. In turn, E_t is the product of the installed generation capacity of the project, the expected capacity factor of the generation technology (the ratio of actual generation to maximum possible generation), and the length of a time period[4].

[4]https://www.energy.gov/sites/prod/files/2015/08/f25/LCOE.pdf

INTERNAL – WHAT IS INCLUDED?

The final LCOE figure is then patently determined by the choice of parameters used in its calculation and the effect of altering them may be significant. Moreover, the sensitivity of the LCOE of individual generation technologies to changes in different parameters is not constant. The LCOE of technologies for which the cost of fuel is either zero or a negligible share of their cost structure, such as wind, solar, and nuclear power, are most sensitive to changes in the discount rate due to the front-heavy structure of their cost profiles. This is illustrated in the graph below, based on median data points from the International Panel on Climate Change[5], in which the weaker sensitivity of fuel-based generation technologies to changes in the discount rate is clear.

The Impact on Levelised Cost of Increasing the Discount Rate from 5% to 10%



[5]https://www.ipcc.ch/site/assets/uploads/2018/02/ipcc_wg3_ar5_annex-iii.pdf

The sensitivity of the levelised cost method to the selection of cost parameters has naturally resulted in a wide divergence in calculated LCOE figures – inputs are chosen by the individual or group making the evaluation and are based on a wide variety of sources.

This is not in itself a failing of the method, it merely reflects the aleatoric nature of the eventual costs of electricity generation (that, given the inherent uncertainty of a large number of factors, variability is to be expected and the estimates of that variability used by different individuals will differ). The future movements of the price of natural gas or the commodity prices that affect the cost of power plant construction, for example, cannot be known with certainty and so estimates are based on expectations or forecasts of which there are a great number – although some reflection of that uncertainty can be illustrated with the use of the scenario analysis method.

Moreover, the liberalisation of electricity markets and accompanying privatisation of national utility companies has reduced the public availability of accurate cost data upon which parameter estimates can be based. The wish of private firms to ensure their competitive positioning in markets has made them less willing to share potentially sensitive cost data with external agents[6]. This phenomenon is perhaps most acute in the nuclear industry, in which a limited number of international suppliers compete in the export market but can be found in other generation markets. In general, this has meant that estimated capital costs – and other variable costs more broadly – are increasingly grounded on a reduced number of potentially idiosyncratic cases or speculative abstract analyses.

This is not always a bad thing – many individual parameters are affected by project-specific characteristics. The capacity factor of renewable generation technologies, for instance, is set by the availability of the underlying resource – whether it be the wind or the sun – and will vary according to local weather conditions. This is reflected, for example, in the LCOE analysis conducted by Lazard that assumes different illustrative capacity factors for wind generation projects in different countries, ranging from 22%-30% for Japan to 45%-55% for Brazil[7]. In a similar vein, the US Department of Energy presents LCOE figures both with and without federal tax credits for renewable generation projects to account for the fact that different projects may qualify or apply for different ones[8].

However, while accounting for project-specific characteristics may allow a levelised cost estimate to more accurately reflect a particular reality, it necessarily reduces the universal applicability of the estimate – as a greater degree of the parameters pertain to an increasingly specific set of circumstances that may not exist elsewhere. This is true even for generation technologies of the same type, as the Lazard example above illustrates. Conversely, a desire to calculate a more broadly 'representative' LCOE estimate will necessarily increase its uncertainty – captured by wider confidence intervals, for example – as local variations are averaged together.

[6]https://www.oecd-nea.org/ndd/pubs/2015/7057-proj-costs-electricity-2015.pdf
[7]https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf
[8]https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

The balance struck between these opposing forces will therefore have a significant impact on the usability and representational scope of the calculated LCOE estimates – this point illustrates a deeper truth that not only does the levelised cost method integrate a large number of different parameters but it also integrates a large number of individual judgements or assumptions concerning those parameters, whether it be the choice of a particular discount rate, the degree of project specificity, or the sources from which parameter estimates are taken.

This is important because these assumptions and a thorough rationale for why they were made are rarely – if ever – made apparent by those who use LCOE estimates to advocate for or against particular technologies or groups of technologies (often confined to the footnotes and presented as fact) and their significance is seldom stressed.

Finally, it should be noted that as use of the levelised cost method has become increasingly ubiquitous there is an increasingly strong incentive for advocacy groups and others with vested interests in the fortunes of a particular electricity generation technology to employ selective judgement in their calculations. The simplicity of an LCOE estimate – a simple to grasp, cost-per-output figure – permits it significant cut through. As a result, estimates have become weaponised, insofar as there is now a clear incentive for advocates to shop around for favourable parameters, now that a ranking of LCOE estimates is seen as a ranking of the value in full of different electricity generation technologies, which as the next section will demonstrate is far from the case.

B External – What is Missed Out?

The issue of what the levelised cost method fails to capture, the characteristics and impacts of the different power generation types that are beyond its scope, lies at the heart of its unsuitability as a means by which to compare the various methods of producing electricity and so to inform decision-making.

To a certain degree, this is well understood by most sector stakeholders yet use of LCOE estimates as the dominant means by which to evaluate and support particular technologies continues on unabated – as already stated herein, this is partly a result of the simplicity and accessibility of the statistic (or, alternatively, the complexity of more holistic measures) but is also reflective of an critical underappreciation of the significance of the factors that it excludes, particularly those that pertain to the power system as a whole.

The most apparent failing of the method is its treatment of all electricity generated as a single, homogenous product to be accorded a single price. This ignores the fact that the value (as reflected in the market price) of electricity supplied varies extensively over the course of a typical year and so the shape of the production profile of different generation technologies, in particular those of dispatchable and intermittent technologies, is of great significance[9], particularly given the cost of storing electricity and the technical difficulty of doing so over long periods. The time-dependent nature of power generation using technologies that are reliant on weather conditions and thus potentially unable to produce electricity at times of high prices necessarily renders them economically disadvantaged from a value perspective.

[9] P. Joskow, Comparing the Costs of Intermittent and Dispatchable Electricity Generation Technologies, (2010)

EXTERNAL – WHAT IS MISSED OUT?

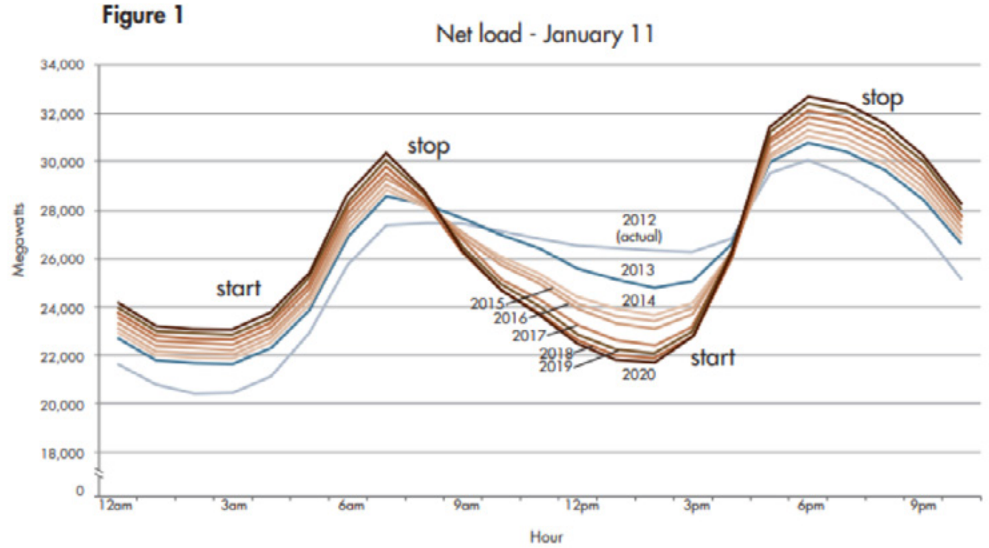
As a result, the levelised cost method overvalues intermittent power generation in relation to baseload, dispatchable alternatives by evaluating electricity generation on only cost and not value terms.

Indeed, the relative degree of resource availability offered by different generation technologies is becoming increasingly important. As the penetration of intermittent renewable technologies increases in most power grids, dispatch (or the demand) of conventional suppliers is increasingly driven by the irregular variability of renewable resources. Given its low marginal cost and priority dispatch in some power grids, the residual load duration curve (the remaining electricity required to balance supply and demand after renewable power has been delivered to the market) faced by conventional suppliers is to an increasing degree driven by periods of low intermittent renewable energy availability . This makes clear the importance of assessing the expansion of a particular generation technology – particularly those based on intermittent energy sources – within the context of the entire grid rather than on an isolated project basis.

One of the earliest examples of this interaction between intermittent renewable and conventional generators is the 'Duck Curve' in California, which made clear the impact on dispatchable generation of the timing imbalance between solar power generation in the state and peak demand . As shown below , solar production is concentrated during the early afternoon, when demand is typically low, and halts in the evening when demand is at its highest, requiring a significant and swift ramp-up in conventional production.

As before, the timing of electricity generation affects its value – the weather-dependent nature of renewable generation not only prohibits its agile adaption to fluctuations in market demand but also implies that production is highly correlated between producers employing the same renewable technologies (seen in the widening of the 'Duck Curve' as installed solar capacity in California grew over time). From the perspective of operators, the latter point implies that value diminishes as solar capacity increases – as more weather-dependent generation occurs coincidentally, supply increases and a downward pressure on market price is exerted.

Figure 1



[10] https://www.cell.com/action/showPdf?pii=S2542-4351%2818%2930386-6
[11] https://www.nrel.gov/news/program/2018/10-years-duck-curve.html
[12] https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf
[13] https://www.iea.org/data-and-statistics/charts/the-california-duck-curve

Moreover, the intermittency of renewable generation technologies affects both the management of the grid and the operation of conventional technologies, such as nuclear power plants, which results in system-level costs that are not captured by the levelised cost method[14].

These integration costs associated with the expansion of intermittent renewable capacity can be decomposed into their direct and indirect components, with the former relating to direct cost increases in the wider system and the latter relating to the way in which increased intermittent renewable generation serves to reduce its own value. Estimates for the system costs imposed by intermittent renewable generation technologies range from 10% to 50% of their levelised cost[15], depending on the scope of the calculation and the share of total generation for why they account.

Direct costs are twofold, the first of which are balancing costs that occur due to the uncertainty of renewable-based electricity generation caused by errors in weather forecasting and minute-by-minute fluctuations in the strength of the underlying resources[16], such as the windspeed. This, in turn, necessitates ongoing operational adjustments by dispatchable power plants (to ensure that the power market remains in balance) as well as the maintenance of an operational reserve, able to bring additional power to the market in a short time. Also, there are grid costs that arise due to the expansion in the transmission network that intermittent renewables tend to require (as site suitability is determined by weather conditions rather than proximity to load centres) and the greater demands placed on congestion management.

The indirect (or profile) costs of intermittent renewable electricity generation relate to its temporal profile – the manner in which generation fluctuates in line with weather conditions over the course of a day – and the way in which its time-dependency necessitates adjustment and accommodation by the wider electricity system[17]. Profile costs are threefold with the first partially illustrated by the 'Duck Curve', namely that increasing intermittent renewable generation reduces the capacity factor (or full-load hours) that can be achieved by dispatchable power plants, as the supply and demand of electricity must balance, and so increases the cost of generation in the residual system. Secondly, the intermittency of renewable generation means that it has a low capacity credit, insofar as it cannot be relied upon to produce at all times if required by the grid, and so conventional or 'firm' capacity cannot be removed from the system on a long-term basis but must remain installed as back-up. Finally, the correlation in time of intermittent renewable generation implies that overproduction is increasingly likely as installed renewable capacity increases and so will require curtailment, in turn reducing its effective capacity factor.

[14]https://spiral.imperial.ac.uk/bitstream/10044/1/54113/2/07835476.pdf
[15]https://www.powermag.com/the-economic-thicket-of-generating-cost-comparisons/
[16]https://publications.csiro.au/rpr/download?pid=csiro:EP187001&dsid=DS3
[17]https://www.pik-potsdam.de/members/edenh/publications-1/SystemLCOE.pdf

A factor of a different type that is ignored by the levelised cost method is the impact of the power sector on the wider economy and, in particular, the manner in which power sector decision-making forms an important part of industrial policy and can stimulate economic development[18].

The direct impact of a decision to invest in a particular electricity generation technology can be assessed in terms of the number of jobs that it creates (both during construction and throughout its operational lifetime), the quality of those jobs as reflected in wage rates, and the wider economic multipliers stimulated by the investment. As shown below, there is considerable variation in the employment effects of different generation technologies with the largest resulting from investment in nuclear power due to its high unit capacity and need for a large and well-skilled workforce[19]. The former also mean that investment in nuclear power has a significant impact on domestic supply chains in construction – in concrete, for example – that lead to further economic multipliers. A final consideration is the degree to which a particular electricity generation technology encourages the technological development of local industry, as opposed to relying to a large extent on the import of equipment and infrastructure, a driver of value that may also lead to future exports.

Two final considerations that relate to industrial policy are the degree to which an electricity sector is able to deliver price stability (or to reduce price volatility) and the extent to which it enables domestic energy security. These factors are in one sense related insofar as an electricity sector dependent on imported fuels, one that has not achieved energy security in other words, will be more exposed to the vagaries of international fuel markets and so more susceptible to sudden price fluctuations. Again, energy security in the power sector must be thought of at the level of system as a whole. Intermittent renewable generation technologies, for example, do not require any fuel, imported or otherwise, to operate but if their installation necessitates investment in natural gas capacity to serve as back-up, fuel imports, and so external dependency, may then increase.

Technology	Jobs/MW	Average Size (MW)	Direct Local Jobs	Average Salary (US$/Hour)	Workforce Income ($ Million/Year)
Nuclear	0.50	1.000	504	31	32.49
Coal	0.19	1.000	187	28	10.99
Hydro > 500 MW	0.11	1.375	156	33	10.79
Pumped Storage Hydro	0.10	890	85	38	6.70
Hydro > 20 MW	0.19	450	86	33	5.79
CSP	0.47	100	47	27	2.62
Gas CC	0.05	630	34	28	2.02
Solar PV	1.06	10	11	15	0.33
Hydro < 20 MW	0.45	10	5	35	0.33
Wind	0.05	75	4	35	0.29

[18]https://energyeconomicgrowth.org/sites/eeg.opml.co.uk/files/2018-02/1.1_Stern_0.pdf
[19]https://www.oecd-nea.org/ndd/workshops/modenps/presentations/docs/9-bradish.pdf

03 Research Findings

The new research findings presented later in this section make clear the fundamental importance of system-level analysis in power sector decision-making and draw attention to a number of the suboptimal and often unintended outcomes that are a consequence of relying on the levelised cost method when doing so.

However, it is of value to begin by considering in general terms how the levelised cost method can lead decision makers awry and the negative impact that its use can have on the successful delivery of a decarbonised electricity system. A reliance on LCOE estimates as the principle means by which advocates for particular electricity generation technologies make their case not only ignores the complexity inherent in modern power grids – illustrated above in the discussion of the ways in which the expansion of intermittent renewable technologies requires response and adaption by existing conventional power plants – but also results in myopic policy formulation in which the long-term nature of the decarbonisation challenge is missed.

The latter point is underappreciated but significant, a short-term approach to power sector policy-making – built upon the levelised cost method and interim decarbonisation targets – increases the eventual cost of decarbonisation by undervaluing the long-term system impact of 'firm' (or dispatchable) low-carbon technologies, such as nuclear power, in relation to intermittent renewables. As a result, there is insufficient investment in those technologies in the near-term, which increases the eventual cost of the total decarbonisation of power generation. Significantly, this result holds even if dispatchable low-carbon resources are more expensive than intermittent renewable technologies in either overnight capital cost or levelised cost[20]. Moreover, and with particular relevance to the nuclear industry, the risk of supply chain atrophy caused by the present underinvestment in new installed capacity threatens future competitiveness and technological development, which may further increase the eventual cost of successful decarbonisation.

Finding One: Nuclear Power has the Greatest Impact on Reducing System-Level Carbon Intensity

The interrelated structure of the electricity sector means that decarbonisation must be thought of as a challenge to be delivered by the system as a whole rather than by individual generation projects. While intermittent renewables and nuclear power are both low-carbon resources in isolation, the former require back-up capacity in the form of relatively flexible conventional power generation, which is typically supplied by carbon emitting natural gas-fired power plants. As a result, an increase in nuclear power generation within a grid would be expected to have a greater impact on system-level carbon intensity than a similar increase in intermittent renewable generation due to the integration requirements of the latter.

[20]https://www.cell.com/action/showPdf?pii=S2542-4351%2818%2930386-6

RESEARCH FINDINGS

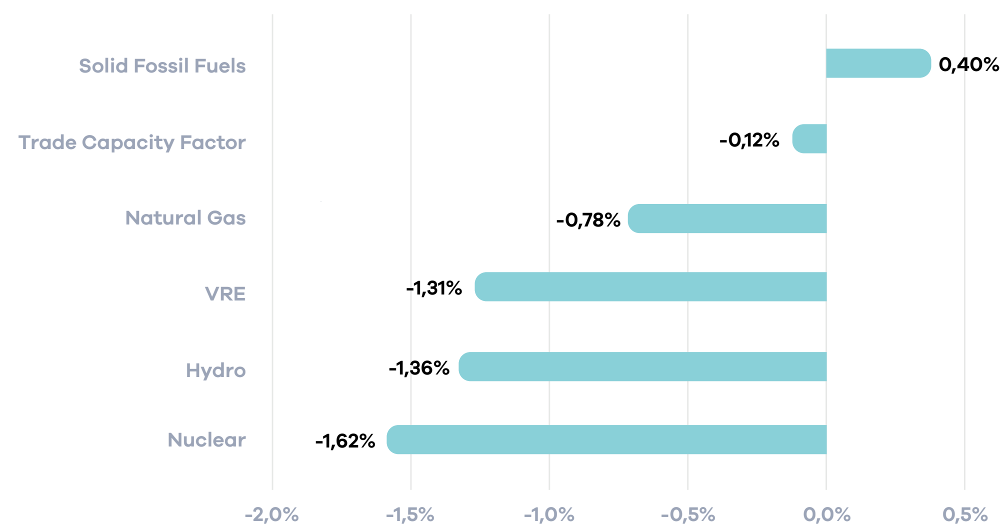
Method: Data on the annual composition of electricity generation by technology for twenty-three European nations was collected for the period 2000 to 2018 from Eurostat[21] and used to calculate the year-on-year change in the share of total generation accounted for each individual technology. To account for the flexibility provided by the potential for international trade, data on the annual export and import of electricity was also collected from Eurostat and a trade capacity factor was calculated, using the total volume traded by a nation and the total generation capacity of that same nation. Then, data on the carbon intensity of power generation in each of the twenty-three European nations was collected (from the International Energy Agency[22]) for the same time period and the year-on-year change in carbon intensity for each nation was calculated.

Finally, a statistical regression was performed with the annual changes in system carbon intensity serving as the dependent variable and the annual changes in the share of total generation accounted for by different energy technologies serving as the independent variables. As a result, the regression coefficients can be thought of as the percentage impact on system carbon intensity associated with raising the share of electricity generation accounted for by an individual electricity generation technology or the trade capacity factor by a single percentage point.

Results and Discussion: The regression output demonstrates that an increase in the percentage share of total generation provided by nuclear power is associated with the largest decrease in system-level carbon intensity when compared to other generation technologies and the trade capacity factor. It also shows a differential impact on power sector carbon intensity between low-carbon technologies, illustrating their relative system value in terms of delivering the decarbonisation of the power sector.

It may seem surprising that different low-carbon technologies do not have a uniform impact on the carbon intensity of the power system as none directly produce carbon emissions during operation. However, this view makes clear the importance of their differing impacts at the system level. As noted above, intermittent renewable technologies require firm back-up capacity for grid stability to be maintained, which is commonly provided by carbon-emitting natural gas-fired generation. This is not the case for nuclear power on account of its dispatchability, a demonstrable source of system value that is not captured by the levelised cost method.

Finding One: Regression Coefficients



The regression coefficients indicate that an increase in nuclear share of total generation is associated with a 24% greater decrease in system carbon intensity than an equal increase in the intermittent renewable share. However, to assess the relative impact on a capacity-weighted basis, the capacity factors of the generation technologies must be taken into account as well. Assuming that nuclear and intermittent power plants operate at 85% and 35% full-load hours respectively, it can be concluded that on a per-MW of installed capacity basis, the impact of nuclear power on system carbon intensity is 34% greater than that of intermittent renewables.

A final result that may also appear counter-intuitive is the negative coefficient of the share of total generation accounted for by natural gas as it is not a source of low-carbon electricity. This can be explained by the occurrence of coal-to-gas switching that has taken place in Europe over the time period under analysis. By replacing coal-fired generation which produces over twice as many carbon emissions per unit of electricity[23], natural gas-fired generation has a positive impact on the carbon intensity of a power system, although one that is smaller than all low-carbon technologies.

[21]https://ec.europa.eu/eurostat/home?
[22]https://www.iea.org/data-and-statistics
[23]https://www.ipcc.ch/site/assets/uploads/2018/02/ipcc_wg3_ar5_annex-iii.pdf

Finding Two: The Diminishing Carbon Intensity Impact of Natural Gas

The reliance of intermittent renewable technologies on back-up capacity provided in the main by natural gas-fired power plants has been defended in some quarters as a temporary measure to facilitate the integration of ever greater expansion of renewable energies – the 'transition fuel' narrative in which natural gas serves as a bridge to an almost wholly renewable-backed grid that excludes nuclear power, usually on levelised cost terms. There are a number of drawbacks associated with this proposal, not least the high risk of stranded assets along the natural gas supply chain in the future as well as its debatable compatibility with stricter decarbonisation targets[24]. Moreover, as the coal-to-gas transition nears completion in a number of European nations, the decarbonisation return on natural gas use will likely fall[25].

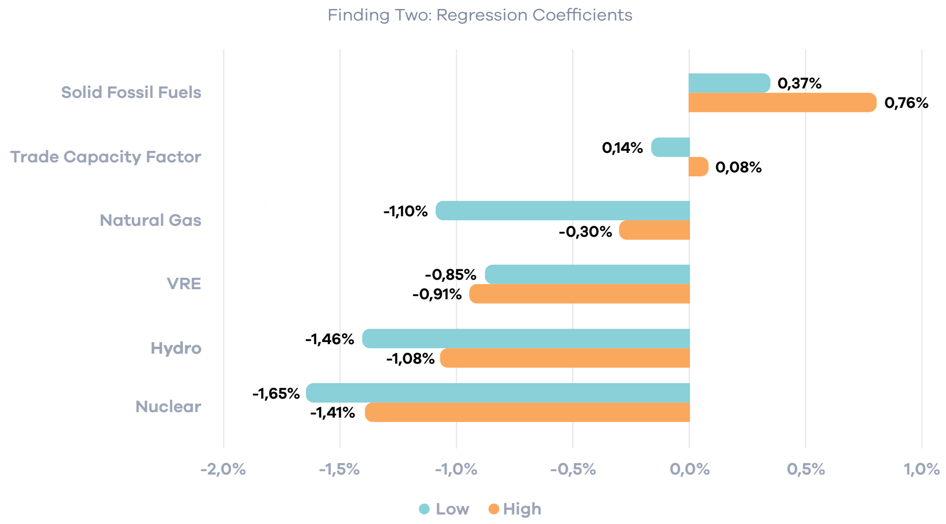
Method:

Starting with the dataset already described, the data where then divided into two groups according to the share of total generation accounted for by intermittent renewables – establishing a 'high' and a 'low' group so that the relationship between natural gas use and the renewable share could be identified.

Then, as before, a regression analysis was performed using the annual change in the carbon intensity of the power system as the dependent variable and th e annual changes in the shares of total generation produced by each technology and the trade capacity factor as the independent variables. The understanding of the regression coefficients is also as before but there can now also be made comparisons between the coefficients of the two sub-samples to assess the impact of an increasing renewable share on the system value of the other independent variables.

Results and Discussion:

A comparison of the two sets of regression coefficients reveals that the impact of increasing the natural gas share of total generation decreases as the total renewable share increases – in other words, that there is a diminishing return on system carbon intensity of natural gas generation. To be precise, the natural gas coefficients indicate a decrease of 73% in terms of impact on system carbon intensity between the two subsamples. When use of renewables remain low and the dominant rationale for increasing the use of natural gas is to reduce the use of more emission-intensive coal there is a greater decrease in carbon intensity than when natural gas is used to provide back-up generation when renewable technologies are unable to operate. In contrast to nuclear power, an expansion of the renewable share does not allow for the retirement of emission producing conventional power plants doing to its intermittency and need for back-up.



The result is significant as natural gas-fired generation remains the primary source of quick ramp back-up generation for renewable energies and is likely to do so as the mass production of cost-effective electricity storage options at scale is yet to be achieved and the feasible development of long-term (or seasonal) storage technologies remains subject to significant technological uncertainty. As a result, the continued expansion of renewable energy in the near-term will have to be accompanied by a greater use of flexible natural gas if the 'transition fuel' narrative is to be pursued. Once again, it requires a system-level perspective rather than one of isolated levelised cost to be able to see the consequences of the interaction between generation types.

[24]https://www.newnuclearwatchinstitute.org/publications
[25]https://www.carbonbrief.org/huge-coal-gas-switch-drives-down-eu-emissions

RESEARCH FINDINGS

Finding Three: The System Capacity Factor Decreases as the Intermittent Renewable Share Increases

As noted above, the 'Duck Curve' makes clear the impact of increased generation from intermittent renewable energy sources on the operation of conventional power plants. The merit order curve – the ranking of electricity bids by operators in order of ascending price in order to determine the electricity supply curve – implies that renewable electricity displaces other suppliers when weather conditions permit generation. As a result, conventional power plants operate for fewer full-load hours and so their LCOE will, all other variables being the same, increase.

However, the time-dependency of renewable energies limits when generation is possible and so the residual load has to be met by those same conventional power plants, now operating at a reduced capacity factor. Moreover, the effect of reduced full-load hours is not constant across all conventional power plants – the larger impact on LCOE will be borne by electricity generation technologies whose LCOE is determined more by upfront investment costs, such as nuclear power, than the cost of either operation and maintenance or fuel. Either way, this intermittency effect – a indirect cost of intermittent generation – would be expected to result in a decrease in the capacity factor of the system as a whole.

Method:

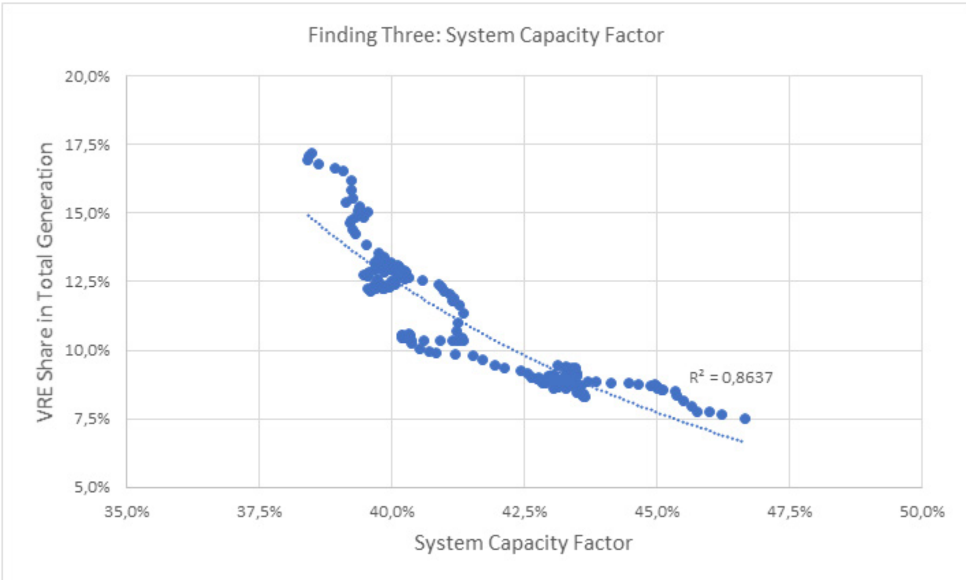
Monthly data on the generation and installed capacity of different electricity generation technologies in the United States of America was collected from the Energy Information Administration[26] for the period from 2001 to 2017. First, a monthly capacity factor for the electricity system as a whole was calculated, followed by the share of total generation held by intermittent renewable technologies.

Finally, a twelve-month rolling average of the system capacity was calculated as the impact of greater intermittent generation was not thought to be instantaneous on the operation of the wider grid and the relationship between that lagged average and the intermittent share was analysed.

Results and Discussion:

There is a clear, inverse relationship between the generation share accounted for by intermittent technologies and the capacity factor of the system overall. In turn, the residual share of load – the volume that is not (and, indeed, cannot) be supplied by intermittent technologies – is supplied by conventional power plants operating at a lower capacity factor than would have been achieved prior to the expansion of the renewable share. This will necessarily have an impact on the residual LCOE and may lead to greater electricity price volatility over time[27], neither of which is reflected in the LCOE of intermittent generation technologies.

Moreover, as the variable renewable share continues to increase, the electricity supplier market becomes increasingly bifurcated into periods when intermittent generation is and is not possible. This increases the need for flexibility in the residual (or conventional) system and so increases the need for ramping (over multiple timescales) and potentially even the need for some conventional power plants to operate in a start/stop regime. As a result, conventional power plants must run under conditions of greater stress, which may lead to higher maintenance costs – another intermittency cost not reflected by the levelised cost method.



[26]https://www.eia.gov/electricity/data.php
[27]https://ideas.repec.org/a/eee/eneeco/v62y2017icp270-282.html

04 Conclusion

This report has shown that the use of the levelised cost method as a means by which to compare different electricity technologies and to advocate for or against their greater deployment is no longer a valid approach.

The research findings presented herein have made clear the importance of evaluating the whole system impact of generation technologies and the inability of the levelised cost method to capture significant aspects of system value. The narrow focus of the levelised cost method is blind to the effects of a particular technology on the operation of others as well as the demands it places on the power sector as a whole. As a result, intermittent generation technologies have been overvalued relative to energy sources that offer significant benefits at the level of the system as a whole – most notably, nuclear power.

This is not to say that there is no place for intermittent generation in a decarbonised electricity sector; that would be unhelpful and misguided.

But it must be acknowledged that the levelised cost method has been one of the principal tools used by advocates for an ever-greater reliance on renewable energies often at the complete exclusion of nuclear power. It is argued that the falling cost of renewable generation has rendered nuclear power uneconomic and so undesirable. This conclusion is a reflection of the weakness of the method, if the single frame of reference is levelised cost and all cownsiderations of system value are dismissed, then it follows that whichever technology can be argued to have the lowest LCOE should be used almost exclusively. However, system-level analysis, based on an understanding of both the idiosyncratic attributes of different generation technologies as well as the multidimensional nature of system value, makes clear the necessity of taking a portfolio or diversified approach to power sector design.

This failing of the levelised cost method is all the more significant due to the required decarbonisation of the power sector.

As noted in the research findings, the effect of intermittent and nuclear generation on system carbon intensity is not the same – an increase in the generation share held by nuclear power is associated with a larger decrease in carbon intensity than a commensurate increase in intermittent generation. This result is of vital importance to our decarbonisation efforts but cannot be appreciated if different generation projects are considered in isolation and evaluated using the levelised cost method. The clear value of the dispatchability of nuclear power – that it does not require emission-intensive back-up – is only readily evident once a holistic view of the power sector is taken. It is clear that successful decarbonisation will not be delivered on a project-by-project basis unless guided system-level analysis.

Annex I

Complete Regression Statistics

Finding One

Regression Statistics	
Multiple R	0.8331
R Square	0.6941
Adjusted R Square	0.6893
Standard Error	0.0408
Observations	391

ANOVA

	df	SS	MS	F	Significance F
Regression	6	1.45	0.24	145.20	1.565E-95
Residual	384	0.64	0.00		
Total	390	2.9			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	-0.0073	0.0023	-3.1392	0.0018	-0.0119	-0.0027
Solid Fossil Fuels	0.3960	0.1365	2.9010	0.0039	0.1276	0.6644
Natural Gas	-0.7795	0.1240	-6.2837	0.0000	-1.0234	-0.5356
Nuclear	-1.6213	0.1687	-9.6101	0.0000	-1.9530	-1.2896
Hydro	-1.3601	0.1169	-11.6305	0.0000	-1.5900	-1.1302
VRE	-1.3062	0.2064	-6.3296	0.0000	-1.7119	-0.9004
Trade Capacity Factor	-0.1237	0.0354	-3.4943	0.0005	-0.1933	-0.0541

FINDING TWO

Finding Two

Low Group

Regression Statistics	
Multiple R	0.7956
R Square	0.6329
Adjusted R Square	0.6200
Standard Error	0.0443
Observations	177

ANOVA

	df	SS	MS	F	Significance F
Regression	6	0.58	0.10	48.85	1.53358E-34
Residual	170	0.33	0.00		
Total	176	0.91			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	-0.0055	0.0042	-1.3111	0.1916	-0.0137	0.0028
Solid Fossil Fuels	0.3723	0.2284	1.6298	0.1050	-0.0786	0.8232
Natural Gas	-1.1024	0.1730	-6.3708	0.0000	-1.4439	-0.7608
Nuclear	-1.6550	0.2565	-6.4525	0.0000	-2.1613	-1.1487
Hydro	-1.4631	0.1640	-8.9192	0.0000	-1.7869	-1.1393
VRE	-0.8522	1.1464	-0.7433	0.4583	-3.1153	1.09
Trade Capacity Factor	-0.1400	0.0448	-3.1213	0.0021	-0.2285	-0.0514

High Group

Regression Statistics	
Multiple R	0.9175
R Square	0.8417
Adjusted R Square	0.8361
Standard Error	0.0298
Observations	177

ANOVA

	df	SS	MS	F	Significance F
Regression	6	0.80	0.13	150.69	2.36E-65
Residual	170	0.15	0.00		
Total	176	0.95			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	-0.0077	0.0028	-2.7735	0.0062	-0.0132	-0.0022
Solid Fossil Fuels	0.7629	0.1724	4.4256	0.0000	0.4226	1.1032
Natural Gas	-0.3018	0.1728	-1.7470	0.0824	-0.6428	0.0392
Nuclear	-1.4102	0.2023	-6.9715	0.0000	-1.8095	-1.0109
Hydro	-1.0829	0.1607	-6.7389	0.0000	-1.4002	-0.7657
VRE	-0.9059	0.2258	-4.0122	0.0001	-1.3517	-0.4602
Trade Capacity Factor	0.0778	0.1143	0.6810	0.4968	-0.1478	0.3035