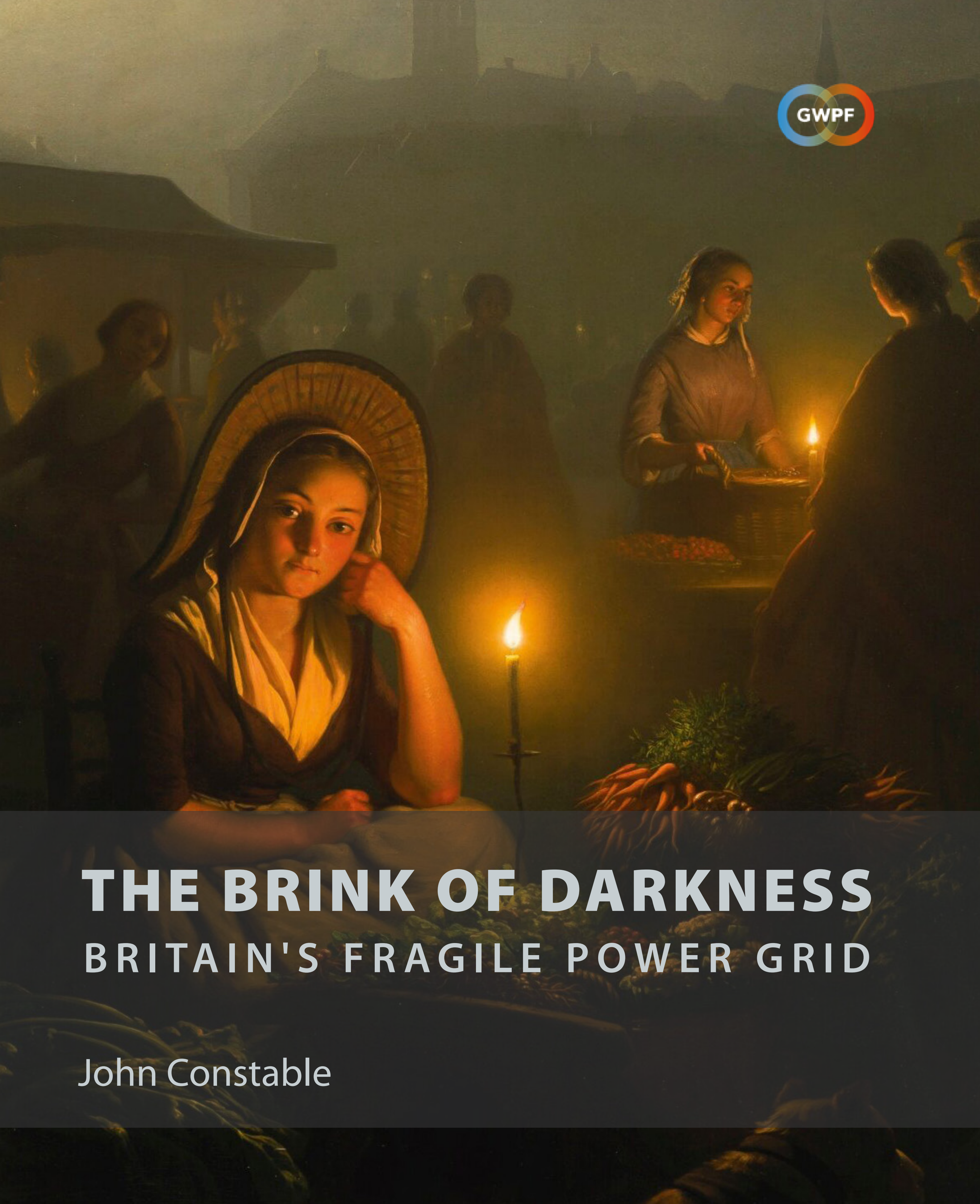

THE BRINK OF DARKNESS

BRITAIN'S FRAGILE POWER GRID

John Constable

The Global Warming Policy Foundation
Briefing 47

The Brink of Darkness: Britain's fragile power grid
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Contents

About the author

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Executive summary

- Steadily rising costs since 2002, and two major events in the last twelve months, one instantaneous and one still ongoing, have exposed the underlying and increasing weakness of the United Kingdom's renewables-dominated electricity supply industry, requiring insupportably large injections of additional resources to patch the system and secure supply.
- Since 2002, when renewables were introduced on a large scale, the cost of balancing the grid has risen from £367 million to £1.5 billion per year. This is largely due to measures to manage the intermittency of renewables, particularly wind and solar. Grid expansions, such as the £1 billion Western Link, to connect up far-flung windfarms, are also adding to consumer bills.
- In spite of this expenditure, in August 2019 a lightning strike on the high voltage grid caused a loss of supply in London and other places affecting 1 million customers for over an hour, with knock-on effects that continued for weeks. Lightning strikes are common events and in a robust system would pass almost unnoticed.
- This spring and summer, low demand resulting from the Covid-19 lockdown has further exposed the fundamental inflexibility and weakness in the UK electricity system. Measures to address the risks arising from the presence of uncontrollable renewables generators at times of low load may cost as much as £700 million over the period April to August alone.
- In response, National Grid has invoked the possibility of compulsory and uncompensated disconnection for smaller generators, and introduced a new scheme to encourage flexibility in the renewables sector, but these measures will save only £200 million, leaving a £500 million bill still to be paid.
- Even this is doubtful. Management costs over the 22–25 May Bank Holiday weekend amounted to over £50 million, including £18.9 million to reduce large-scale wind output, and up to £7 million to switch off smaller, 'embedded' wind and solar generators. It is likely that these costs will have to continue for some time after August.
- These measures are at least doubling the cost of supplying a unit of electrical energy to a consumer.
- Generators and suppliers are unable quickly to increase their prices to recover this cost and they have already lobbied Ofgem to defer the bill until 2021–2022. This will further increase prices paid by consumers, who are already burdened by £10 billion per year of renewables subsidies. Post-Covid, these costs are insupportable.
- In order to avoid prolonging and deepening the post-Covid recession, Government should immediately seek to reduce electricity system costs by suspending renewables support and instead should adopt a cost-minimisation policy focused on nuclear and on gas.

The fragility of a renewables-based system

It has been increasingly evident for quite some time, as the papers collected in this monograph demonstrate, that the electricity system of the United Kingdom is becoming weaker as progressively larger volumes of electricity from renewable sources such as wind and solar are forced into the system by regulation. This systemic enfeeblement is happening in spite of substantial increases in the cost of the system, as regulations and measures to support renewables are put in place. These range from more network cables to flexible demand, as well as complex and expensive operational structures such as constraint payments. The purpose of committing these resources is to compensate for the thermodynamic defects of wind and solar, and a corresponding increase in consumer costs is required to fund the reallocation. On a nationally significant scale, resources that consumers would have preferred to use elsewhere are now being swallowed up by the electricity industry. However, in spite of its scale, this reallocation of resources has not been sufficient to produce an electricity system as flexible and resilient to exogenous shock as the conventionally engineered system that preceded it.

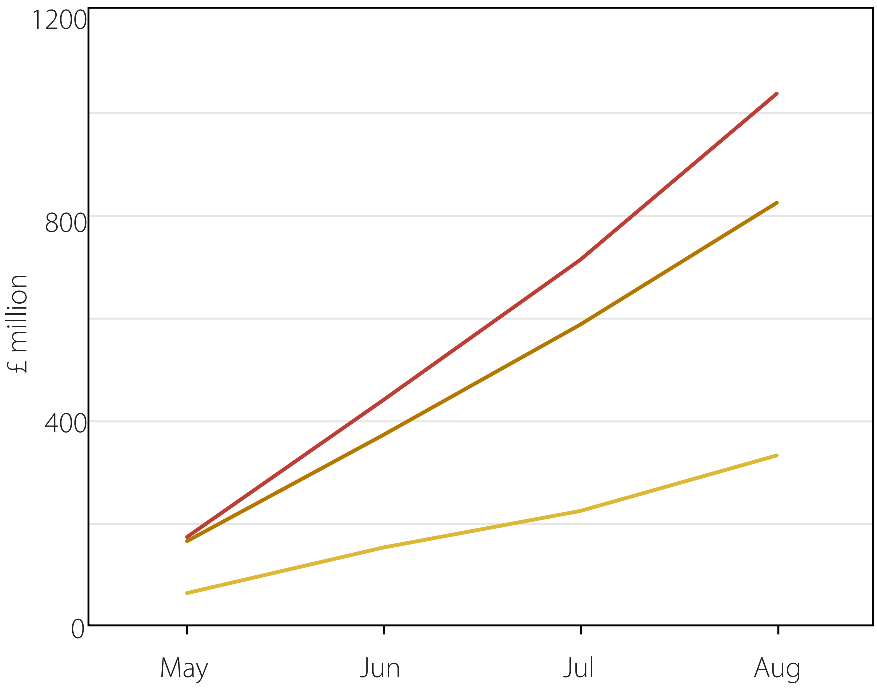
The scale of these additional costs and the resource reallocation can be illustrated by the costs incurred in the Balancing Mechanism. These so-called Balancing Services Use of System (BSUoS) charges are incurred in the first instance by National Grid ESO (Energy System Operator), and are then billed to both generators and suppliers, and ultimately recovered from consumers through higher retail prices. BSUoS costs are not the only additional system costs caused by renewables – transmission network charges are also significant– but they are a large part of that total cost, and a fundamental index of the problem.

In 2002, before the rapid growth in renewable generation, the annual BSUoS cost stood at £367 million. By 2019 it had risen to £1,482 million, which, even allowing for inflation, is a very large increase. A growing share of asynchronous, uncontrollable generation, such as wind and solar, was the predominant cause of the increase, and yet more increases are expected in the medium and longer term. However, the impact of Covid-19 has brought that medium-term future abruptly into the present.

National Grid ESO's initial BSUoS cost forecast for this coming year, 2020–21, was £1,478 million, but on the 15th of May it revised this figure in the light of difficulties caused by the management of renewables during the period of low demand for electricity caused by the Covid-19 lockdown. The new forecast for 2020–21 was for a BSUoS cost of £2 billion, most of this additional cost being concentrated in the summer months.[1] Figure 1, based on data from National Grid ESO's revised monthly forecast, gives the details of the scale of the additional charges expected from May to August, and also the effect of newly announced special measures, which it hopes will reduce the scale of the cost increase.

Figure 1: Cumulative BSUoS costs for summer.

Outturn 2019, post-Covid forecast for 2020, and with remedial measures. Source: National Grid ESO: BSUoS Forecast Summary: May to August 2020.[10]



Without the new services, NG ESO expected the total BSUoS cost from May to August to amount to just over £1 billion, as compared to £333 million for the same period last year. With the new measures in place, it is hoped that this total can be limited to just over £800 million, an increase of £500 million on the previous year. It is this additional cost that accounts for the ESO's revised estimate that total BSUoS costs in 2020 will amount to £2 billion rather than £1,478 million.

Of many uncertainties affecting this projection, two deserve special attention. Firstly, the estimate seems to assume that the problems caused by the lockdown will continue through to August. This could be wrong; lockdown might be completely lifted before August, with demand rising once again. On the other hand, it might continue, or, even if it is lifted wholly or partially, the economic damage incurred over the spring and summer might reduce demand for electricity substantially for some time to come, being only partially offset by rising demand during the darker and colder winter months. Intuitive pessimism suggests that the latter is more likely, and that the extremely high BSUoS costs noted here for the period up to August are likely to persist after that time. It is notable that the NG ESO forecast does not commit itself to a view on this question.

Secondly, the reduction in additional cost, from £1 billion to £826 million, is dependent on the 'new services' working as intended and at the cost predicted. This is obviously uncertain, and a comprehensive audit will have to wait for the release of full details of deployment and cost.

The uncertainty in cost arises because the root problem addressed by these services is the presence of uncontrollable and unpredictable wind and solar – particularly embedded solar – which makes the system hard to handle at times of low load, when renewables make up a large proportion of the generation online. Since the precise scale of the problem is highly uncertain even days in advance – let alone months – the cost of the remedy is also difficult to determine.

A measure of this uncertainty is the rapidity with which large costs can accumulate over a short period at a moment of stress. For example, the management costs over the four days of one Bank Holiday weekend, the 22nd to 25th May, amounted to nearly £51 million. £39 million of that cost was in the Balancing Mechanism, of which £18.9 million was paid to reduce large-scale wind output. Costs that mount at this sort of rate as the result of the conjunction of relatively unpredictable circumstances are inherently hard to foresee.

Although the problem is unpredictable, we can be precise about the character of the remedies proposed, the most important of which the ESO refers to as 'Optional Downward Flexibility Management' or ODFM, a term as notable for its inelegance as for its opacity. This scheme is already costing significant sums, with up to £7 million incurred over the Bank Holiday to reduce embedded renewables, including wind and solar, and a further £4 million to reduce input from the interconnectors, which would otherwise have presented an unacceptably large potential loss.

ODFM can best be understood as Generation *Down* and Demand *Up*; in other words, it is a way of removing some generation, at a cost, and incentivising sources of demand to consume electricity at a time convenient to the system. National Grid's own, hastily written, explanation describes the state of the scheme so far:

> [ODFM] is an opt-in service for small scale renewable generators to receive payments from National Grid ESO if we ask them to turn down or turn off their generation of electricity. The service is also open to providers who can increase their demand during the periods when the service is required. It's seen a great take-up so far, with over 2.4 GW of capacity from 170 smaller generators signed-up to respond if we make an instruction from our control room – including 1.5 GW of wind, 700 MW of solar and almost 100 MW of demand turn-up.[2]

This opt-in scheme is supported by another of the new services, known as 'Last resort disconnection of embedded generation', proposed by National Grid ESO on the 30th of April,[3] and permitted by Ofgem on the 7th May.[4] Last resort disconnection permits the grid to instruct distribution network operators to disconnect embedded generators such as wind and solar without compensation if a system emergency requires it, and only if none of the commercial arrangements is adequate to the task. How well this would work in practice is open to question, but it seems likely that National Grid expects the mere possibility that the measure might be applied to be sufficient to intimidate embedded generators into making themselves voluntarily available through the ODFM scheme.

The average size of the generator already engaged in the ODFM scheme, taking NG ESO's figures above, is 16 MW, but there may be individual units of up to 50 MW, the largest size usual on the distribution network. It is in effect, therefore, a supplement to the constraint payments system, as currently operating in the Balancing Mechanism, which is almost exclusively confined to generators connected to the transmission system, though there are a few exceptions. Constraint payments to reduce wind power output are of course a notorious running sore, and have cost British consumers nearly £800 million since they began in 2010. In 2019, they cost £139 million, a large slice of the BSUoS total, and so far this year have amounted to £123 million, with a new daily record of £9.3 million scored on the 22nd of May.[5] The total paid to wind farms over the bank holiday weekend, from the 22nd to the 25th of May, amounted to about £15.7 million. These payments are likely to continue in tandem with the ODFM payments, and will remain significant.

Renewables are not the only plant being paid to cap output. Sizewell B nuclear power station has also been restricted, reducing generation from 1.2 GW to 0.6 GW on the 7th May, and still at the time of writing operating at this reduced level. The cost of this measure is as yet unknown.

There is no public explanation of the reasons behind this capping of Sizewell's output, but the motivation is not difficult to infer, and it is very different from the reasons underlying constraint payments to wind in the Balancing Mechanism, or ODFM payments to wind and solar. At a time of low load and high input from wind, solar and interconnectors, all of which are asynchronous and provide little or no inertia, it is hazardous for the residual synchronised generation fleet, which is guaranteeing the stability of the overall system, to contain a single large unit, such as Sizewell B. Should that unit trip, say because of a frequency disturbance elsewhere in the system, a large further fall in frequency could result, with a cascade trip around the system as a possible consequence, unless sufficient response and reserve generation is being held on hand. For example, transmission system load is currently falling as low as 15 GW or less due to a combination of low lockdown demand and embedded wind and solar input.

In such a situation, Sizewell's 1.2 GW would be 8% of load and, with transmission-connected wind and interconnectors providing about 50% of load, but little or no inertia, it would represent about 15% of the inertia-capable capacity on the system. Providing sufficient response and reserve as an insurance policy against its loss and thus secure the system would be expensive, and we can infer that the ESO has decided that it is cheaper to cap Sizewell B. However, that decision means that the system is now short of 0.6 GW of high-quality inertia-delivering generation. Replacing the inertia lost by capping Sizewell B, probably with combined cycle gas turbines, will also have a cost.

Even from a brief sketch such as this, it should be obvious that the System Operator is taking extraordinary – and extraordinarily costly – measures in order to secure the system over the summer. These are being presented to the public as a necessary reaction to the unexpected impact of the lockdown required by the viral pandemic. This is a half-truth: a conventional electricity grid would have been readily able to secure the system in the same circumstances, and to do so at low cost. It would even have been able to take advantage of low fossil fuel prices.

Furthermore, while Covid-19 and the lockdown might be accepted as in themselves unforeseeable, an exogenous shock of some kind is not only foreseeable but certain. Accidents and 'events' happen. A robust and flexible conventional electricity system has general versatility, which enables it to address such shocks, no matter what their character. The fragile, renewables-based system that we currently possess can barely deal with the expected; a surprise causes a crisis.

Putting together the experiences of the August blackouts last year, described elsewhere in this document, and the impact of Covid-19 on demand, what we have learned over the last two years is that the UK electricity system is inflexible and fragile. A lightning strike – a minor event – causes a major blackout. Low demand resulting from nationwide public health measures results in a cost spike so large that it causes cash flow and cost-recovery concerns for the industry, even though these costs are usually passed through to the consumer.

Anxiety at system costs in the sector's largest companies is a new development, marking yet another stage in the decline of the UK electricity supply industry, and merits further consideration. On the 20th of May, very shortly after National Grid ESO published its revised BSUoS estimate on the 15th, Scottish and Southern Energy (SSE) submitted a proposal to modify the Connection and Use of System Code (CUSC), entitled *CUSC Modification Proposal 345*, hereafter CMP345. SSE noted that the increased costs were unexpected, high and would be potentially destabilising to certain industry interests, including presumably themselves. Briefly, they were worried that because BSUoS costs were charged almost immediately, they and others would be faced with high short-term outgoings that they would only be able to recover through increased prices charged to consumers in the longer term, resulting in cash flow problems in the near term. Noting the increase in estimated annual cost from £1.48 billion to £2 billion, SSE wrote:

> This 25%+ increase in the quantum to be recovered is further compounded by (i) it being applied, in practical terms, over a third of the 2020/21 year (May–August) rather than the whole year; and (ii) over a smaller charging base, with demand in GB down circa 20% due to Covid-19 lockdown/demand suppression. The combined impact is that BSUoS costs are forecast to increase by around 90% on average from June–August, with a high probability of BSUoS in individual periods effectively doubling the total cost of electricity. [6]

That is to say, the measures required to stabilise the electricity system in the presence of low conventional and high renewables generation effectively double the cost, a bill that has to be paid to National Grid immediately by both suppliers and generators. This is troubling, as SSE observes:

> The effect of recovering the additional costs arising from the unprecedent Covid-19 event from those parties under the status quo arrangements would be profound as they will be unable to fully recover the amounts via retails tariffs (for Suppliers) given fixed price contracting and price caps, or via wholesale prices (for Generators) given that most sales for May to August generation have already been made before indications of these significant BSUoS cost increases over forecast were given by the ESO.

SSE proposes therefore that payment of the *additional* BSUoS costs from April 2020 to March 2021 be deferred and spread evenly over daily payments in April 2021 to March 2022.

In justifying this truly exceptional request for deferral, SSE identifies both a 'commercial' risk, described above, and a risk to the 'safety and security' of supply, which is still more ominous. SSE writes that:

> ...significant impact on the safety and security' of electricity arises, in particular for generators in GB, as they are faced with these sudden and substantial additional costs which they are unable to fully recover in the wholesale market given forward trading timescales. This, in turn, could threaten the commercial viability of some of those generators who, in these times of significant system management issues for the ESO (hence the highly abnormal additional BSUoS costs), could cease trading/operating, which could impact on the security of the electricity system.[7]

The prospect threatened here is that some generators would fail financially and withdraw from the market. A hard heart might suspect theatrical exaggeration, bullying Ofgem into permitting a long deferral of costs, but there is in truth good reason for thinking that companies with longer-term power purchase agreements – and many renewables generators have such things as part of their hedging strategies – may indeed find it difficult to fully recover these costs given forward trading timescales. SSE, the owner of a portfolio of 2 GW of onshore wind and 580 MW of offshore wind, will understand this industry-wide difficulty very well.

Similarly, SSE will have a strong understanding of the problems to the supply sector, although it is no longer an electricity supplier, having sold its domestic retail business, comprising about 3.5 million customers, to OVO in January this year. This sale increased OVO's share of the domestic market in Great Britain from 4% to about 16%, making it the country's second biggest electricity supplier, after British Gas. Taking on such a major portfolio is not without growing pains, and indeed OVO has in the last week announced that it will be making 2,600 employees redundant, closing offices in Glasgow, Selkirk, and Reading, with other redundancies in Perth, Cumbernauld and Cardiff. This is a highly controversial decision, and the GMB union has described it as 'a massive betrayal of promises made to workers and politicians that the sale to OVO would not result in job losses'.[8] A very large increase in BSUoS liabilities, all payable in the very short term, can hardly be welcome to OVO.

Fortunately for generators such as SSE and suppliers such as OVO, Ofgem has accepted the request made in CMP345, and in a letter to National Grid of the 22nd of May, recommended that a modification to the BSUoS charging schedule be considered 'on an urgent basis' to spread the high costs this year over future years.[9] OVO and SSE, and other generators and suppliers, can breathe more easily, perhaps. The increased cost of BSUoS is now the ESO's problem until 2021–2022, but it is a large company with broad financial shoulders and it shouldn't break into a sweat over this burden, although there is clearly a risk that some of the parties with deferred BSUoS obligations may not still be trading when those obligations start to become due in 2021–2022.

For the consumer there is little to celebrate here. The industry has shown complete unwillingness to absorb any of these exceptional costs, and is trying to persuade Ofgem to agree that they should feed through next year in full to electricity consumers: industrial, commercial and, where the price cap permits, domestic. Because of that price cap, considerable inequality in the distribution of the cost burden is to be expected.

The details of the matter have a grim fascination, but we should not allow ourselves to be distracted by the economic melodrama and the agony of individual companies. There are much larger issues at stake here. The current electricity system crisis is not a one-off event, a singularity the like of which we will never see again. Our electricity system is fragile and unable to respond to the unexpected without requiring a vast injection of new resources, funded by consumers. This time the exogeneous shock was a public health measure, but tomorrow it will be something else.

Any investigation that government undertakes, and one has to hope that the Treasury will review Ofgem's eventual decision as well as National Grid ESO's handing of the BSUoS crisis, should approach these matters as a symptom of an underlying problem, namely systemic weakness in the electricity sector.

Indeed, given the strong possibility that the current problems will continue in some form after lockdown due to a prolonged and perhaps severe economic downturn, there is a very strong case for immediately acting to suspend other policies, for instance the subsidies that give renewables a guaranteed dispatch, and return to a cost-minimisation strategy over the entire electricity industry. Such a policy would almost certainly have the consequence of driving wind and solar and biomass from the system, and allowing gas and nuclear to deliver a robust and cheap supply. But if there is any hope of an economic recovery after Covid-19 there is really no alternative.

Balancing the grid in times of low electricity demand

As I write this at 8.26 a.m. on the morning of the 8th May, a Friday but a national holiday in the UK, we are waiting to see how National Grid ESO (Electricity System Operator) will cope with the combination anticipated of low demand for electricity and high output from the 12 GW of solar generation capacity connected to the distribution network (as opposed to the transmission network).

Energy from this source reduces transmission system demand at around midday and after, well before the evening peak, resulting in a novel and somewhat bizarre dual peak to the daily demand most days, as can be clearly seen in Figure 2. This data was published by National Grid itself, and describes load for a week at the start of May 2020.

The operator's problem is to keep sufficient conventional rotating plant online to provide stabilising inertia,[11] while at the same time making space for generators granted effective 'must-run' status, namely wind power and solar power. These do not contribute inertia. In addition, with very low load, that inertia must be provided in chunks small enough to render manageable their sudden absence, as a result of a power station tripping for example. At 1.2 GW, Sizewell B nuclear power station is rather large for the job.

However, National Grid's task today is made that much easier by the fact that combined wind generation, on- and offshore, is expected to be not much more than 1 GW in total, from a nationwide fleet of about 23 GW. The solar forecast is also lowish, at just over 6 GW in the early afternoon, only 50% of the solar fleet's peak capacity. It will be interesting to discover, as we eventually may, how much of that low output is the result of low winds and cloud cover, and how much has been bought off the system with bilateral trades, and at what cost.

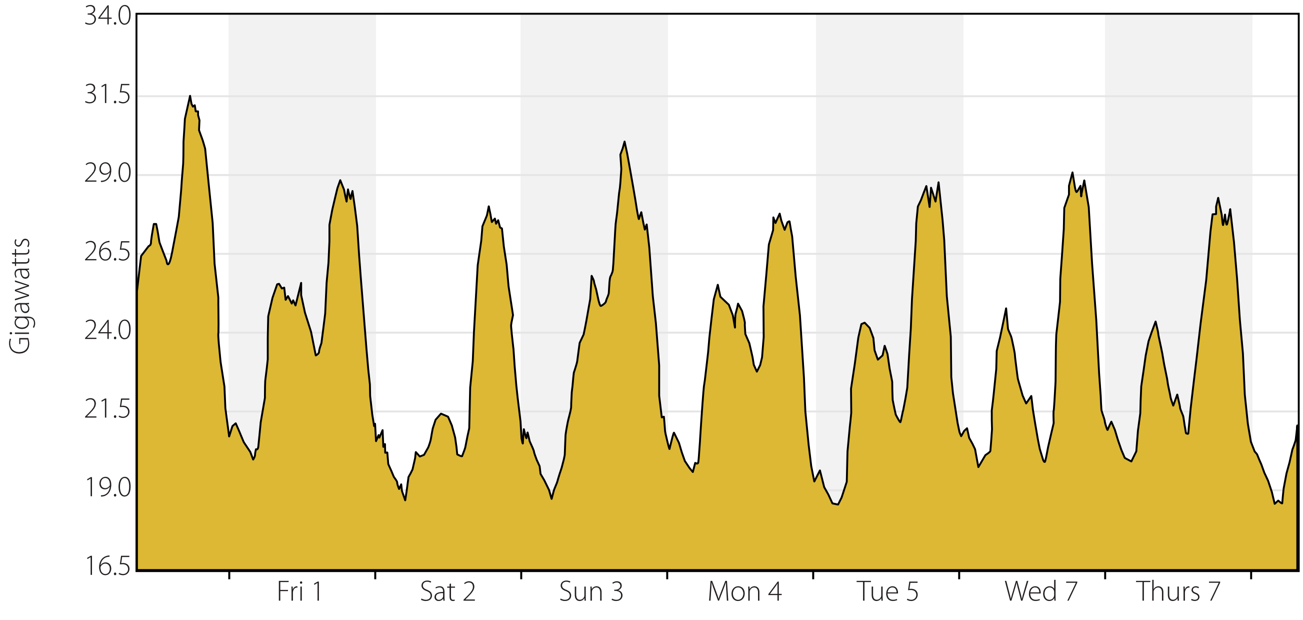


Figure 2: UK transmission system demand, 30 April–8 May 2020.

The trough in demand in the middle of most days is clearly visible. Data: National Grid

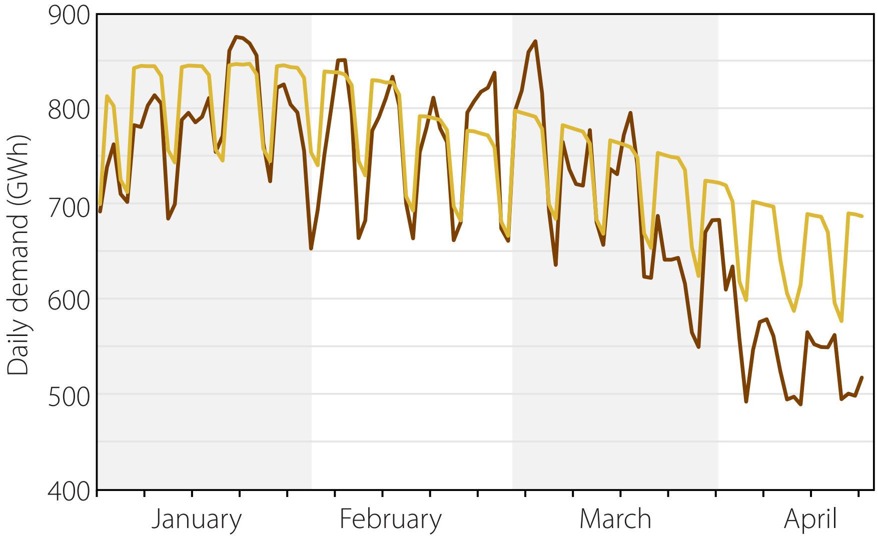
The electrical grid and the lockdown

The restrictions on economic and personal activity imposed to address the spread of the coronavirus are reducing electricity demand in the UK to unusually low levels, increasing the difficulties of operating the system, particularly in the presence of embedded solar and wind generation.[12]

As a result of restrictions on economic activity and personal movement, designed to reduce the rate of transmission of Covid-19, there are striking anomalies in British electricity markets. Figure 3 shows daily electrical energy transmitted over the network, and reveals evidence of a substantial fall in consumption. Domestic use may be rising as a result of the lockdown, but it is nowhere near offsetting the fall in industrial and commercial demand.

Figure 3: Low electricity consumption in 2020.

Daily electrical energy transmitted over the GB grid, 1 January to 23 April, 2020 versus historical average.

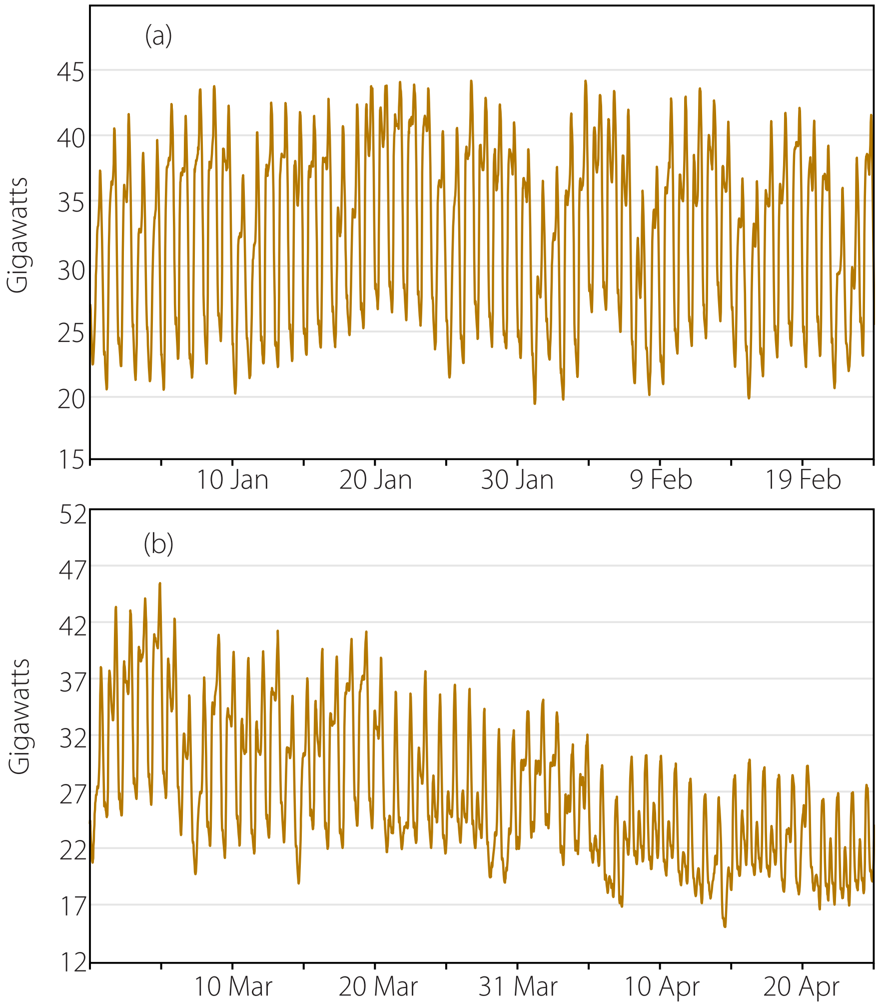


Of course, that decline has to be understood against the background of what is normal for the time of year, and the yellow line shows that demand normally begins to fall from January onwards. The brown line shows that this year was no exception, with the decline beginning well before the first warnings about Covid-19 were given. Furthermore, demand was already low relative to the historical norm for these months because of unusually warm weather. Consequently, some part of the decline seen towards the end of the chart is to be expected. Nevertheless, even when these factors are taken into account, the abrupt nature of the decline in consumption after the 23rd of March is obvious.

Furthermore, there is a clear loss of the familiar structure in the pattern of demand, a feature which is still more evident in the pattern of instantaneous load on the network by half-hourly settlement period. Before the lockdown (Figure 4a), the pattern of load was highly but regularly variable, exhibiting repetitive periodicities on several timescales, all patterns well known to the grid operators. After the lockdown began (Figure 4b), the pattern of electricity demand is temporarily more chaotic, as it moves towards a new and less differentiated equilibrium at a lower level. This is not only new and unfamiliar territory for the system op-

Figure 4: Half-hourly GB electricity demand.

(a) 1 January to 24 February 2020; (b) 1 March to 23 April 2020.



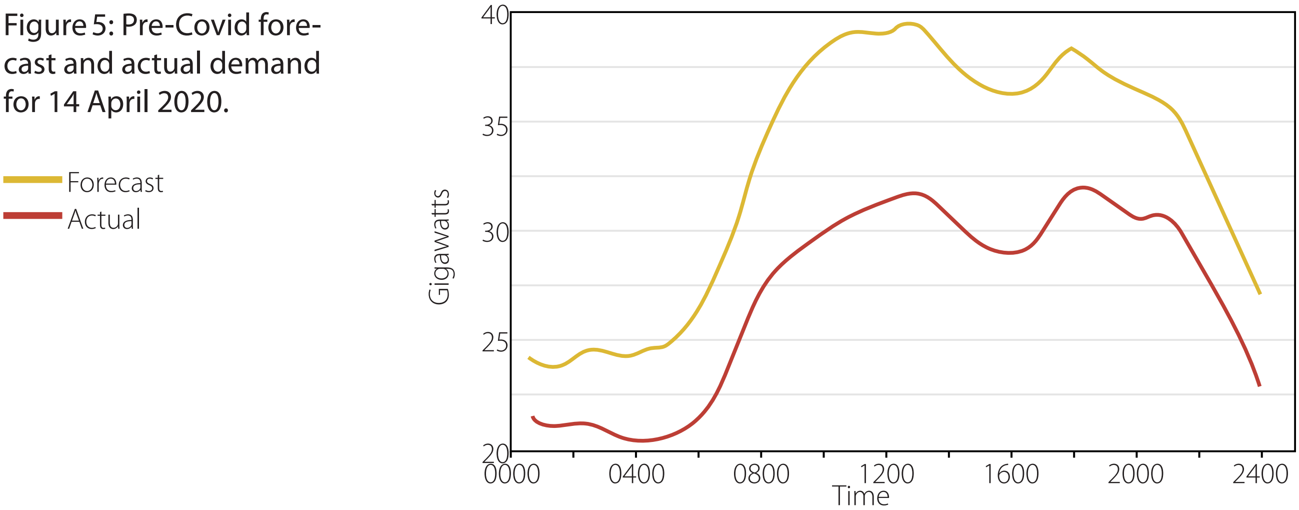
erators, but has also accelerated the arrival of problems produced by large and inflexible renewables fleets, problems the system is probably not quite ready to deal with.

National Grid ESO's Summer Outlook for electricity, published on 15 April 2020, puts a brave face on the matter, but cannot conceal the difficulties. The ESO's principal concern is a combination of low demand and a high proportion of inflexible or relatively inflexible renewable generation, leading to system balancing problems. Assuming that demand cannot be increased on request, the operator must prevent hazardous increases in voltage by reducing generation, while at the same time maintaining sufficient inertia to preserve system stability.

There are already significant reductions in demand, and National Grid ESO's medium-impact scenario envisages these continuing into the summer, with a demand reduction of 7% overnight and 13% during the day. The high-impact scenario involves reductions of 13% overnight and 20% during the day. In fact, reductions approaching the high-impact scenario are already being observed, with National Grid commenting that in April the UK electricity system saw low loads typical of the warm holiday months of July and August.

To illustrate this point, the Summer Outlook provides a graphic comparing actual demand on 14 April 2020 with the demand that would otherwise have been expected (Figure 5). The largest demand fall in the chart appears to be in the order of 19%, and generally the currently observed reduction is, as NG comments, 'between [the] medium impact and high impact scenarios' considered in the Summer Outlook. One might on that basis suspect that the summer impact scenarios are overly optimistic, but it is probable that National Grid is expecting the lockdown restrictions to be eased, keeping demand suppression within the bounds of its high-impact scenario. If, on the other hand, the restrictions are maintained or even strengthened, then the possibility of demand cuts exceeding 20% are clearly possible.

Figure 5: Pre-Covid forecast and actual demand for 14 April 2020.



A reduction approaching 20% on spring and summer demand poses real difficulties for control-room operators, since they are now working with a generation fleet that is, to a large degree, non-dispatchable – 23 GW of wind and 12 GW of solar power for example – and may therefore seek to provide energy to the system even when not required. Table 2 of the Summer Outlook describes a maximum demand of only 25.7 GW in the high-impact scenario, and a minimum demand of 15 GW, a minimum that has already been observed in April. In between these limits, the operator must retain sufficient conventional rotating plant to provide stabilising inertia, but if required also find room for 23 GW of wind and 12 GW of solar power, both uncontrollable.

Of the two, it is the solar fleet that is giving it the most cause for concern. It can afford to be relatively relaxed about wind because, firstly, output tends to be low in the summer months, and, secondly, because they have extensive experience of constraining wind off the system through the Balancing Mechanism (at a cost of £101 million so far this year). That said, it is highly significant that the Summer Outlook refers to the use of an additional instrument, namely 'direct trade' to buy wind farms off the system.[13] Bilateral trades of this kind have not been used intensively for quite some time, and their return is a sure sign of emergency measures. It's a topic to watch.

Solar, on the other hand, is a looming and novel difficulty, now brought suddenly and alarming close. National Grid presents a chart to illustrate the impact that embedded solar generation can have on transmission demand (Figure 6).

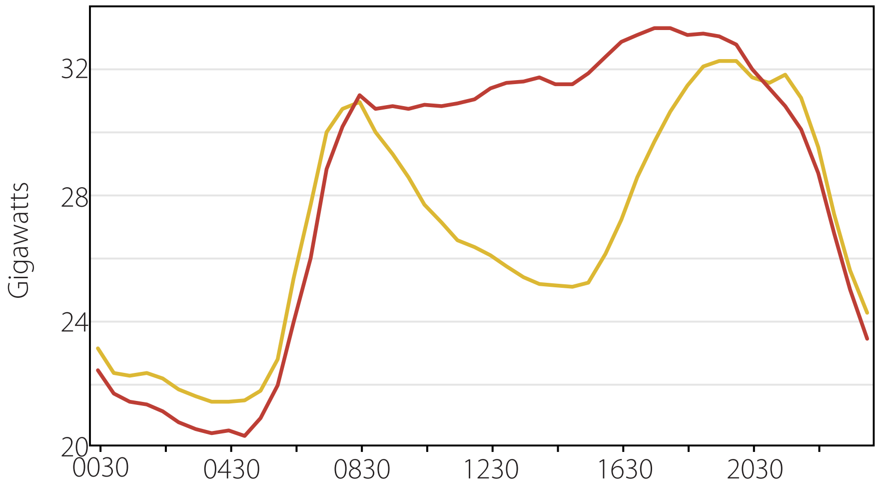


Figure 6: Impact of embedded solar generation on transmission system demand over the day.

The red line is a day with low solar infeed, the yellow line a day with high solar infeed. Source: NG ESO, Summer Outlook (2020), p. 11.

14 May 2019 (high solar)
4 June 2019 (low solar)

The Summer Outlook remarks of the days described in this chart that:

> These two dates share similar temperature and embedded wind properties and were both Tuesdays – the only major difference was 7.5GW of embedded solar generation.

Its concern is that if a similar or greater event, up to the 12 GW maximum of solar installed, were to occur with only 15 GW of demand, there would be a real risk to the stability of the system. It sketches out what it will do in this sort of event in three crucial sentences:

> ...when low demands coincide with high levels of renewable generation that is not synchronised with the grid, system inertia is lower meaning that the impact of any frequency events are greater. This is where our new inertia services are relevant and another reason why synchronous generation may be required to remain on the system. If demand levels fall close to the level of inflexible generation on the system, we may also need to issue a local or national Negative Reserve Active Power Margin (NRAPM). To date a limited number of local NRAPMs have been issued, but none at a national level.[14]

An NRAPM is a warning that the ESO may need to give 'Emergency Instructions' to a generator or generators to cut off their supply of electricity, even to the extent of having to trip off the system immediately, and regardless of inconvenience or cost. It is a severe level of warning, and at a national level would indeed be unprecedented. What is not clear from this statement is how embedded solar sites – of which there are quite literally hundreds and thousands – even of the larger size, would be taken promptly off the system by such an Emergency Instruction. The ESO will clearly have, as they say in the control room, a 'difficult day'. It might be awkward for the rest of us, as well as expensive.

Increasing electricity system fragility

The UK's electricity network is likely to become significantly weaker within five years, due to falling short circuit levels (SCLs). These will reduce the reliability of protection systems designed to limit the geographical extent of supply loss during a fault, and also make it more likely that asynchronous sources of electricity, such as wind, solar and high voltage direct current (HVDC) interconnectors, will disconnect during a fault. Ironically, SCLs are falling because of the rising input from asynchronous sources. A remedy for this problem is unlikely to be cheap. Who will pay?

Electricity networks of any size are complex systems, with all the advantages and disadvantages that this implies. The uninitiated believe that the principal threat to such systems is the failure of electricity producers – the generators – to meet the demands of consumers for energy, resulting in a blackout. This is not completely mistaken, but blackouts on a modern and developed electricity system are in fact only rarely directly caused by shortfalls of generation, say as a result of poor system planning, a power-station accident, or unexpectedly high consumer demand. System operators are nearly always able, even at short notice, to call on sufficient additional resources either to increase generation or reduce demand, though of course this remedial action comes at a considerable cost.

A rather more probable cause of a system blackout is a transmission system equipment failure, at a transformer for example, or a sudden external event, such as a storm or a vehicle – a plane or a ship perhaps – damaging a transmission line. In a weak or poorly designed system, such accidents will overload other transmission lines, which then themselves have to shut down to avoid damage, sending a further ripple of overloading through a large part of the network, forcing generators themselves to come offline and resulting in a widespread blackout.

Apart from ensuring a high specification for the components used and a high standard of design and construction, the best protection against such accidents is to ensure that the system is sufficiently stable under stress that it can contain a loss of supply to a small part of the network. This capability is usually automatic, since action must be taken in milliseconds to prevent a cascade of faults. Accidents will happen, but a strong system can prevent a local problem from becoming a regional or even a nationwide disaster.

The strength of the system must be continually monitored to ensure that it will be stable under stress, a precaution that would be necessary at any time, but has particular relevance in the UK at present due to the rapid and dramatic changes in the electricity supply industry being driven by climate change policy. It is therefore only prudent for National Grid ESO (the Electricity System Operator) to be undertaking a review with the aim of ensuring that its System Operability Framework is adequate to the task. The first results from its Operability Strategy were published in November and December 2018,[15] with updates being provided in its regular Operational Forums.[16]

National Grid identifies five areas of concern: frequency control, voltage control, restoration (i.e. recovery after a blackout), stability, as discussed above, and thermal (transmission line temperature). All are important, but to judge from the volume of commentary devoted to it, it is stability that is giving most cause for concern. Specifically, SCLs in Great Britain are predicted to fall considerably over the next decade. The SCL is the current that will flow through the system during a fault; an accident affecting a transmission line for example. It is, as National Grid explains, 'a measure of strength', and a 'key parameter for protection systems' in the network itself and also in other equipment attached to it.[17]

With low SCL the transmission system protection systems, which function to 'isolate faulty equipment…limiting the fault effect on the wider system',[18] could, in National Grid's own words, 'take longer to operate or not operate as designed',[19] meaning a loss of supply to a much larger area. Furthermore, some generators, specifically wind and solar farms, and the protection systems of some sources of electricity, such as HVDC interconnectors, may be much more likely to disconnect in the event of a fault if SCLs are low.

As it happens, SCLs are falling in the GB network because of declining input from synchronous, conventional generation, such as coal-fired power stations and combined cycle gas turbines, and rising input from wind, solar, and HVDC links, which are asynchronous and do not provide support to the SCL in their vicinity. Consequently, areas where there is at present a great deal of wind and solar already have low SCL, and this is expected to spread to other areas as synchronous input declines and more asynchronous renewables and interconnectors are built. Figure 7, reproduced from National Grid's publication on the subject, shows predicted regional SCLs in Great Britain in 2020, 2025, and 2030.

Figure 7: Regional short circuit levels in Great Britain, 2020, 2025, and 2030.

Source: National Grid ESO, System Operability Framework: Impact of Declining Short Circuit Levels (December 2018), p. 2.

Scotland and the West Country already have low SCL, due to high levels of wind and solar respectively, and the analysis projects a falling trend elsewhere, with the largest declines foreseen in the north-east and the east Midlands, probably because of the closure of coal-fired generation in those areas. Only north Wales escapes, since it fortunately has a pumped storage plant, Dinorwig, with unusual design features that make it well equipped to support SCL.

As noted, low SCLs tend to increase the risk that asynchronous generators and HVDC interconnectors will fail to ride through a fault arising from an accident on the system. National Grid explains that this is due to the fact that such equipment uses phased locked loop converters, a technology that relies on voltage waveform to provide it with information about system condition. If SCLs are low, a fault will cause the voltage waveform to become disturbed, with important consequences:

> When the phase locked loop measures a more disturbed voltage waveform it might not provide the right information back to the converter and the converter might not respond in the right way to a fault. In this situation there is a risk that the converter will lose connection to the network.[20]

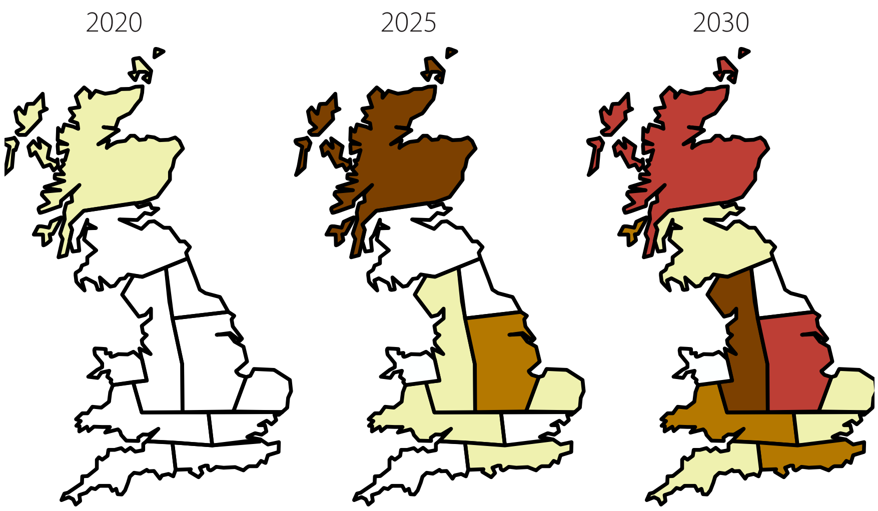
To put that in concrete terms, low SCLs make it more likely that wind and solar and HVDC interconnectors will disconnect during a system fault, just when they are needed most to prevent a blackout.

National Grid provides a simplified map representation of the increasing phase locked loop risk. This is redrawn in Figure 8, which uses colour coding to show the percentage of the year affected by each level of risk in 2020, 2025 and 2030.

Scotland is already at significant though moderate risk, being exposed for about 15% of the year; presumably the winter months when wind input is high. The rest of the country is quite unaffected. By 2025, however, Scotland is at risk for half to three quarters of the year, and other areas are beginning to feel some degree of

Figure 8: Regional Phase Locked Loop (PLL) Risk, 2020, 2025, and 2030.

Source: National Grid ESO, System Operability Framework: Impact of Declining Short Circuit Levels (December 2018), p. 3



Percentage of year at risk
- 0
- 1–15
- 16–50
- 51–75
- 76–100

exposure. By 2030, only north Wales and the north-east are free of risk, and in Scotland and in the east Midlands it will be an almost year-round fact of life.

Taken together, these two figures show that the GB electricity network is set to become significantly weaker within five years, and much weaker within a decade. Obviously, National Grid's aim in undertaking such assessments is to assist in addressing the problem, and it is to its credit that the matter is being aired so candidly. There is no doubt that this is a serious problem, and that National Grid takes it seriously. However, the documents so far published are longer on diagnosis than remedy. To an extent this is forgivable, since the obvious and economic solution – to run existing synchronous generation such as gas and nuclear much more while running solar and wind much less, and in the future to build more gas and nuclear and less wind and solar – is not compatible with the current politically driven selection of renewables as a means of reducing emissions. With the obvious and economic options ruled out, one is left with speculative and costly alternatives: sophisticated power electronics perhaps, in combination with a requirement for wind and solar and interconnectors to improve their ability to ride through faults. While such things might be possible, none would be cheap, and such measures would certainly do nothing to alleviate concern that the United Kingdom's electricity supply industry is greatly reducing its productivity, and making high-cost electricity inevitable. Applying layer after layer of ingenious solutions to problems that have only arisen because of flawed policy-driven distortions of the market and of engineering decisions appears unwise.

Whether the consumer will be shielded from the burden of supporting measures to address falling SCLs, amongst other difficulties, is doubtful. Ofgem, the regulator, is notoriously weak when climate change enters the equation. But some comfort can be taken from remarks elsewhere in the recent Operational Forum presentations. Discussing the cost of balancing the electricity system,[21] which has risen very dramatically over the last decade and now stands at £1.3 billion a year, National Grid very properly expresses the view that more of the costs of measures undertaken to address problems arising in the security and reliability of the system should be met by 'those [generators] exacerbating the issue'.[22] This would at least provide a pricing signal to those generators at present taking a more or less free ride on the system and its consumers, and encourage them to find remedies that are better value for all.

In the longer run, the United Kingdom should obviously be considering whether a large fleet of asynchronous generators, such as wind and solar, is a wise or an affordable choice for an islanded grid that can only secure interconnection with its continental neighbours through HVDC cables that are themselves also asynchronous.

The role of distributed generation in the UK blackout of 9 August 2019

It has been widely claimed that distributed (or embedded) generation, such as solar and wind connected to the low voltage distribution network, reinforces electricity system stability. The final reports into the widespread blackout of the 9 August 2019 show that this is not the case. Distributed generation is now under the spotlight as a leading cause of the severity of the blackout, and as a hazard increasing future risks to security of supply.

Both the UK electricity market regulator, Ofgem, and the Energy Emergencies Executive Committee (E3C) of the Department for Business, Energy and Industrial Strategy have now released their final reports into the blackout on 9 August 2019, which disconnected over 1 million consumers for nearly an hour, with knock-on impacts that persisted for days in many cases, and in one case – an oil refinery – for several weeks.[23]

The two studies have different roles. Ofgem's work, which is now almost complete,[24] concentrates on regulatory compliance; that is to say, on whether the relevant parties – National Grid, the distribution network operators, and the generators – breached the terms and conditions of their various licenses. In essence it is a retrospective, forensic and essentially historical study. The E3C work is more forward looking and aims to examine measures that should or are being taken to:

- reduce the likelihood of a recurrence of a similar blackout
- improve the way such a blackout is handled in the event that it cannot be prevented.

The two studies are, as far as I can tell, entirely consistent, but they are complementary, and they need to be studied together.

Those who have been following the blackout story from the outset, as well as more casual readers of press stories on the subject, some of which I have discussed elsewhere,[25] will want to know what new facts and analytic interpretation of the blackout emerge from these two studies.

The answer is that there is a good deal, but it is not initially obvious, and at first glance readers may be disappointed. While there are some new – or at least newish – facts, these are mainly confined to details, and often about the consequences of the blackout rather than its causes. For example we learn that some four hospitals – not just the much-reported case in Ipswich – were disconnected,[26] and that National Grid perhaps over-zealously reconnected Hornsea 1 before it was confident that the 'technical issues' affecting that windfarm, which had without doubt contributed to the problems, had been fully understood. We also learn that a total of 371 rail services were cancelled, and 220 part-cancelled, with three Transport for London tube stations and eight rural signalling stations all disconnected, though without significant effect on services.[27]

Many of these details are certainly important in themselves, and Ofgem even singles out for particular criticism National Grid's hasty reconnection of Hornsea,[28] but the principal novelty and value of these two documents is not in such material minutiae pure and simple, but rather in the general and cumulatively damning description of weaknesses in the UK electricity system that emerges when viewed in the context of the event overall. It is proverbial that electricity systems shift from stability to chaos in fractions of a second, while the causes of a blackout take weeks and months to understand, but the mists are beginning to clear and we are beginning to get to grips with what happened on the 9th of August.

With regard to the story of the blackout, the main narrative has not changed much since last year; a lightning strike trigged the disconnection of, firstly, 150 MW of distributed generation, closely followed by the almost instantaneous loss of 737 MW from the Hornsea 1 offshore wind farm. Shortly after that, the steam unit[29] at Little Barford combined cycle gas turbine power station tripped off. All of this occurred within one second of the lightning strike. The consequent drop in frequency triggered further disconnections of distributed generators. Then the first of the two gas turbines at Little Barford also had to disconnect, closely followed by the other one, and yet more distributed generation.[30]

Even in this sketch of the summary it will be obvious to those familiar with earlier accounts that, while the main facts remain, the light cast on them has changed significantly, and this results in a somewhat different picture. Attention has switched from the two main transmission-system-connected generators – Hornsea 1 and Little Barford, which have been fined £4.5 million each for failing to ride through the fault – and is now focused on distributed generation; that is to say, on generators connected to, and sometimes said to be 'embedded within', the distribution network. These generators are usually invisible to the system operator, and can range from very small domestic systems, right up to what are, by any standard, large onshore wind and solar installations.

The role of distributed generation in the blackout was, of course, known from quite early on in the post-event analysis, but the scale is only now becoming fully apparent, though even at this late stage it remains, and will remain, uncertain. The E3C report goes so far as to remark that:

> There is a significant possibility that the total volume of loss of embedded generation on 9 August is in excess of the transmission connected generation lost during the event.

Since the transmission-connected generation lost comprises Hornsea and Little Barford, and this totals 1,384 MW, we can infer that, over the entire event, somewhere in the region of 1.5 GW of distributed generation disconnected in several closely proximate phases. That is itself a significant quantity, and suggests that, as the E3C report remarks,[31] the total generation loss during the blackout was a monumental 3 GW.

But it is not simply the quantity of distributed generation that disconnected that is striking. The manner in which it was lost is also important. Ofgem notes that when system frequency fell below 48.8 Hz, the distribution network operators (DNOs), disconnected approximately 5% of load, totalling 892 MW of net demand.[32] However, following a hint in the original National Grid Technical Report, Ofgem comments:

> The ESO reported that the net demand reduction seen by the transmission system was only 350 MW. This indicates that approximately 550 MW of additional distributed generation was lost at this point. The reasons for this need to be better understood and addressed to avoid it happening again.

So the DNOs disconnected 892 MW of demand, but the observed benefit to the system at this time of extreme stress was only 350 MW.

The E3C study gives a little further clarity on this point, noting that '550 MW of embedded generation was disconnected, either as part of the LFDD scheme or via another unidentified mechanism'.[33] The low-frequency demand disconnection (LFDD) scheme is the remedial measure taken during a blackout by the DNOs to bring supply and demand back into balance. Thus much, and perhaps all of that 550 MW of embedded generation, was disconnected by measures taken to address the blackout. In other words, because of the presence of embedded generators, the remedial action taken to address a system disturbance actually made the problem worse, cutting the net benefit of the measure.

Ofgem is quite right to say that this problem should be better understood, but it is difficult to see how it can be prevented in the future, as they hope, except by preventing, whenever possible, the disconnection under LFDD of any area where there is any significant concentration of embedded generation. Of course, that assumes that the system operators are still able to choose which areas will be disconnected, but in a severe system disturbance they may not have that degree of control.

How has this problem with distributed generation crept up and surprised us in this way? Who is to blame? Few if any elements within the UK electricity supply industry come out well from the 9th August blackout. Both Hornsea and Little Barford have been penalised. But neither of them are embedded generators, and they have no role in the management of such generation. National Grid was not fined, and superficially emerges from these studies exonerated: Ofgem puts the point unambiguously:

> We have not identified any failures by the ESO to meet its requirements which contributed to the outages.

But this is obviously as much a comment on the licence terms as the performance of National Grid, and both Ofgem and E3C are sharply critical of several aspects of its conduct both before and after the blackout, including the way it handled embedded generation. Ofgem even remarked that:

> …the ESO could have been more proactive in understanding and addressing issues with distributed generation and its impact on system security. [34]

The implication seems to be that, while National Grid was not in breach of its licence terms as electricity system operator, it has been complacent in its attitude towards emerging and novel problems in the UK electricity system. Many commentators, including Colin Gibson and Capell Aris, both former National Grid employees, have said as much over and over again.[35] It will be interesting to see what comes of the E3C requirement that National Grid review the crucial security and quality of supply standard with the aim of understanding the 'explicit impacts of distributed generation on the required level of security'.[36] If the consumer interest is respected, this could be very interesting.

Taken together, these studies of the 9th August blackout reveal systemic fragility problems in the UK electricity supply industry, but not only within the production side of the industry. National Grid, the generators, the DNOs; none emerge smelling of roses. Moreover, the E3C report also observes that the consumer sector itself is poorly prepared.[37] As a matter of fact, they are encouraging consumers of all kinds to develop 'strong business continuity plans' covering 'a range of credible power disruption scenarios'. This is MBA jargon, but is not too hard to put into everyday French: *Sauve qui peut!*

It seems probable that consumer-side weakness is the outcome of a long period of robust electricity supply, under the CEGB and its inheritors, meaning that consumers never had to test, adapt or even go to the difficulty and expense of developing measures to ensure their lives and businesses were robust in the context of a fragile electricity system. They could rely on the system. That is not the case today.

The costs of a largely decentralised generation portfolio, much of it composed of low-inertia generators such as wind and solar, are not limited to the technical athletics of the system operator, but also involve the need for a forewarned and forearmed consumption market. Thanks to energy and climate policies, British consumers, from households to hospitals, must now ensure that they are able to handle, not only the more extreme grid management measures required by a 'smart', 'clean' system, but also the consequences emerging when those measures prove inadequate. Taking up the slack, which is what 'strong business continuity plans' ultimately means, will not be cost free.

UK energy consumption and weak productivity growth

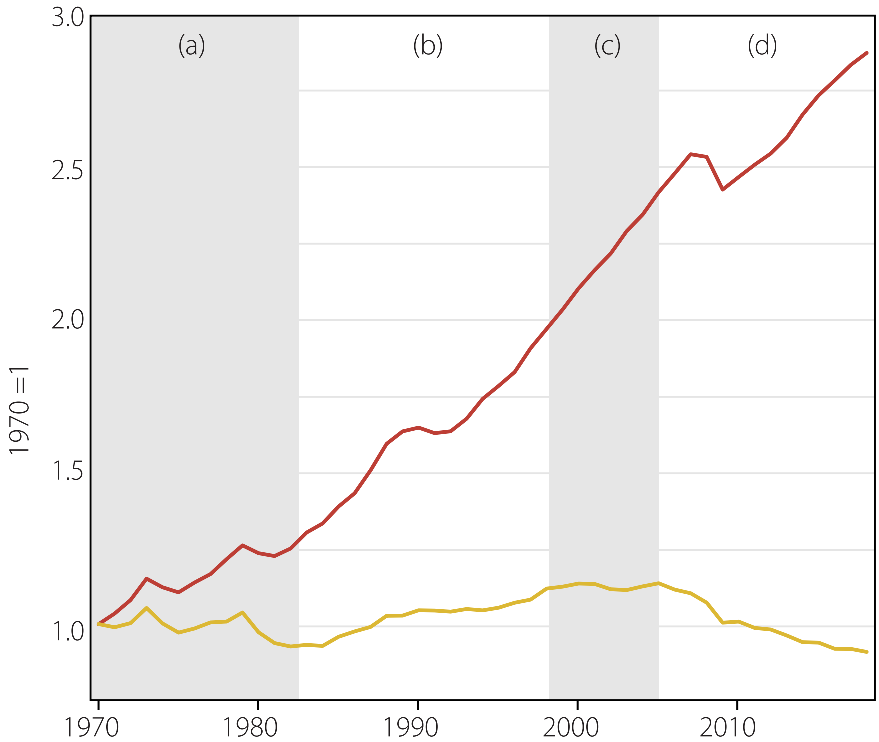
Falling energy consumption in the United Kingdom is not receiving the attention it deserves. While similar to the norm prevailing among the EU 28, the UK pattern is very strongly at variance with global trends, which see significant increases in all sectors. There is a clear possibility that this fundamental difference is revealing a leading causal factor behind the weak productivity growth in the United Kingdom since 2008, yet it is hardly considered by commentators calling, perhaps correctly, for aggressive 'innovation' as the answer to the 'productivity puzzle'. Until they do so, their appeals will be in vain: costly energy makes it rational for innovators to be risk averse.

Figure 9 shows total primary inland energy consumption and UK GDP from 1970 to 2018.

Figure 9: Energy consumption and GDP. 1970–2018.

Energy consumption figures are temperature corrected. GDP on a chained volume measure (black line). Source: DUKES Table 1.1.4.

GDP
Inland energy consumption



Beginning with the macroscopic pattern, one observes that, while energy consumption over the period has been more or less stable, GDP has exhibited a strong rising trend. This undermines claims that 'de-linkage' of energy consumption and GDP is a recent phenomenon, due, for example, to efficiency measures, the digital economy and dematerialisation. On the contrary, this data shows that de-linkage is a long-standing phenomenon, and probably not to be explained by recent novelties, but rather by factors that are simpler and more fundamental.

Further doubts are cast on the validity of a naïve assertion of de-linkage by examination of the finer structure of the data, in which we observe a varied and subtle relationship between energy consumption and GDP. Firstly, there is an irregular but clear downward trend in energy consumption from 1970 to the early 1980s (a). After this, we see a moderate but steadily rising trend up to the later 1990s and early 2000s (b), after which there is a flattening off (c) and then a marked decline from 2005 onwards (d), the latter being acute compared both with the previous downward trend in the 1970s and indeed with the preceding upward trend from the early 1980s. In a little over ten years, the increase in consumption evident over the period 1982–2001 has been reversed, and in 2018 the UK consumed around 10% less than it did in 1970. This change would be notable in itself, but is particularly so when we recall that over this period population has risen from about 56 million to 65 million and that GDP has more than doubled.

As already noted, some see evidence in this data that energy consumption and economic growth have been de-linked in the last decade or so (d). There is clearly some ground for this view in the fine structure of the data at the end of the series. But equally there is evidence for an earlier de-linkage, from the 1970s to the early 1980s (a). This can only undermine confidence in any argument suggesting that the current divergent trends result from recent societal and technological modernisation, principally the digital economy. It is at least possible, and in my view probable, that some other explanation accounts for both the divergence in the 1970s and that in recent years. For the time being, the de-linkage case, never theoretically strong, should be regarded as weak in comparison with alternatives.

For example, it might be inferred that the energy consumption required to support the economic growth visible in GDP is taking place elsewhere in the world. On this view, for a short period in the 1970s, the UK economy became more reliant on energy conversion elsewhere in the world for the goods and services it consumed, a trend that has recurred in a stronger form in the present day. If this were correct, the de-linkage of GDP and energy in the UK would be illusory.

Furthermore, the fine structure of the data also reveals that, even in the divergent curves at the beginning and end of the series, there is still some degree of linkage between inland energy consumption and economic activity. For example, in both 1973–1975 and 1979–1981, and again after 2008, falls in energy consumption are paralleled by falls in GDP. Indeed, in the 1970s and the early 2000s the relationship is notable for a subtle but highly suggestive character: GDP and energy are clearly related, rising and falling together over the short term, even as they are exhibiting divergent secular trends over the longer term, with energy consumption falling and GDP rising in both periods.

These two phases at either end of the series contrast sharply with the straightforward correlation visible in the two decades from the early 1980s up to the early 2000s, when GDP and energy consumption rose together. Indeed, one interpretation could be that the Britain of today has more in common with that of the 1970s than with that of the 1980s and 1990s, a rather shocking conclusion, but one that cannot, I think, be rejected quite out of hand. It is worth asking whether a tendency towards a healthier economic function, with a more reasonable balance between inland production and imported consumption, is represented by the 1980s and 1990s, and a less satisfactorily balanced, or even anomalous operation by the 1970s and the present day.

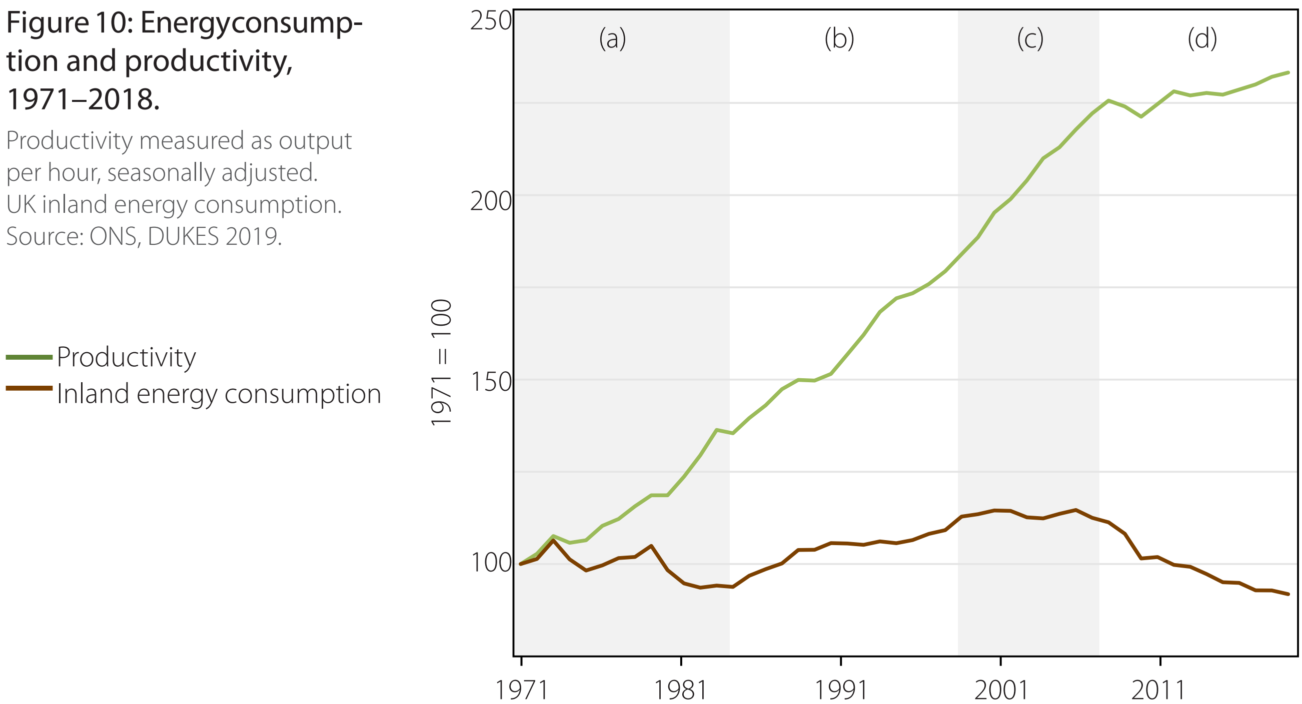
Analysis along these lines may also shed light on the notorious 'productivity puzzle': the unprecedented and so far inexplicable sluggishness in productivity growth since 2008. Figure 10 charts UK inland energy consumption data (brown line) and output per hour worked (green line).

Several of the points made above in relation to GDP can be made again here. Although the 1970s saw productivity growth rise and energy consumption fall (a), there were still signs of a positive correlation in the fine structure of that divergent trend, just as there is in the divergence from around 2008 onwards (d). Furthermore, as with GDP, the central body of the data (b and c) is characterised by the positive correlation of rising energy consumption and rising productivity growth in the period from the early 1980s to the early 2000s.

But there is also a significant difference. While GDP resumes its previous upwards rate of growth quite promptly after 2008, productivity growth does not, and steers closer, as it were, to the downward energy consumption trend. One might infer, therefore, that energy consumption plays a larger part in productivity than in GDP. That is plausible, since a change in the energy consumption of inland economic activities is almost certain to have a significant and direct effect on productivity; if a production system is under-energised it does less; if the throttle is closed, the engine decelerates. On the other hand, any effect that falling energy consumption might have on GDP can readily be offset by other fac-

Figure 10: Energyconsumption and productivity, 1971–2018.

Productivity measured as output per hour, seasonally adjusted. UK inland energy consumption. Source: ONS, DUKES 2019.



tors. For instance, GDP can be enlarged by the spending of borrowed funds on imported goods, goods that are produced with energy consumption in other territories.

It seems, therefore, that there is some ground for concluding that the unprecedented stagnation of productivity growth since 2008 could be explained at least in part by factors depressing energy consumption, such as sustained and significant increases in energy cost, making it difficult to recover from the economic shock of the crash. This is no mere theoretical possibility, and strong candidates can be found, for example, in the loading of climate-policy subsidy costs onto electricity, starting in 2002, and now amounting to about £10 billion per year, and very high, longer-term taxes on transport fuels, totalling £28 billion a year at present.[38] It is important to recall that both these policy impositions were charged on top of fundamental costs that were and still are themselves rising, making an underlying difficulty much worse.

There is a widespread assumption that the productivity puzzle could be addressed by a determined government focus on the enhancement of innovation. For example, a recent paper by Richard Jones,[39] of the Physics and Astronomy Department at the University of Sheffield, has argued exactly this and has received a generally favourable reception, even in right-leaning and Conservative Party circles.[40]

Jones, in essence following the left-wing economist Mariana Mazzucato's case for an *Entrepreneurial State*,[41] suggests that major government interventions in low-carbon energy, and in health and social care, are 'key ingredients in turning around the productivity problem'.[42] Strangely, he appears to be unaware of the long-term and exorbitantly costly market coercions already favouring low-carbon energy, and is thus in no position to wonder whether those distorting energy policies may be playing a significant role in creating the productivity problem in the first place. But Jones is by no means unusual in failing to take energy seriously, though discussing it at length; and as a matter of fact, hardly anyone gets beyond conventional and empty gestures towards energy as the lifeblood of the economy. However, the GDP, energy consumption, and productivity data discussed above suggests that such an attempt would be worthwhile, and that a great deal could depend on it. Who would disagree with Jones and others that innovation is essential to prosperity? Why, then, is it so difficult to deliver? Because innovation is the experimental combination and application of inventions to satisfy human requirements and is a very high-risk business indeed; the vast majority of innovations are failures. Cheap energy means that those failures are less expensive, and that innovators can afford to take the risk over and over and over again. When energy is expensive it is rational for innovators to be extremely risk averse, as they generally are at present in the United Kingdom.

The current cost of renewables subsidies

The low and much-publicised offshore wind bids for Feed-in Tariffs with Contracts for Difference (FiTs CfDs) continue to confuse many analysts, even those from whom one might expect clear-eyed caution. A writer for the CapX website,[43] to select an example almost at random, quite correctly takes issue with the Labour Party's reckless plans for major public investment in further offshore wind, but does so on the mistaken ground that 'offshore wind is a big success story…delivering ever more clean energy, at ever lower prices, for a fraction of the price of Labour's plan'.

However, and as a matter of fact, none of the low-bidding wind farms have actually been built, and the 8.5 GW of operational offshore wind capacity that is 'delivering' is, without exception, very heavily subsidised. Indeed, the most recently commissioned offshore wind farm, the giant 588 MW Beatrice, off the north-east coast of Scotland, which only became fully operational in the summer of 2019, has a CfD strike price of £140/MWh, now worth £158.73/MWh, roughly three times the wholesale price, and indeed about three times the almost certainly unrealistic strike prices bid in the most recent CfD auctions. It is obviously premature to say that the observed fall in CfD prices bid is a 'success story'. The CfD contracts are very far from firmly binding, and the penalty for abrogration is trivial. It seems likely, bordering on certain, that they are a sly and low-risk publicity gambit, intended to secure a market position, and inhibit competition, in the hope of obtaining a better price by whatever means at a later date.

And of course the cost of electricity from existing offshore wind power has most certainly not fallen; it continues to be very high, like all the other renewable generators in the UK fleet. Perhaps it is worth reminding ourselves just how much that subsidy currently amounts to, and how much it is costing British households.

2.7 Environmental levies							
	£ billion						
	Outturn	Forecast					
	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25
CRC Energy Efficiency scheme	0.5	0.4	0.0	0.0	0.0	0.0	0.0
Renewables obligation	6.0	6.4	6.3	6.4	6.6	6.8	6.9
Contracts for difference	1.0	1.7	2.2	2.5	2.7	2.9	2.8
Capacity market[1]	0.0	1.7	1.1	0.9	0.5	0.7	1.0
Green gas levy	0.0	0.0	0.0	0.0	0.0	0.1	0.1
Environmental levies	**7.5**	**10.2**	**9.6**	**9.9**	**9.8**	**10.4**	**10.8**
Memo: Expenditure on renewable heat incentive (RHI)	*0.8*	*0.9*	*1.0*	*1.1*	*1.1*	*1.1*	*1.1*

Note: The 'Environmental levies' line above is consistent with the 'Environmental levies' line in Table 3.3 of the March 2020 *Economic and fiscal outlook*.

[1] The ONS have yet to include capacity market auctions in their outturn numbers. If they were included, they would have been £0.2bn.

Figure 11: Environmental levies.

Actual (2017–18) and forecast (2018–2024) consumer cost of environmental levies. Source: Office for Budget Responsibility (OBR), Economic and fiscal outlook – March 2019,45 see "Economic and fiscal outlook – supplementary fiscal tables: receipts and other", Table 2.7.

Apart from the Contracts for Difference (CfDs), there are two other systems of subsidy: the Renewables Obligation (RO), and the Feed-in Tariff (FiT). The costs of these systems are recorded in the Office for Budget Responsibility's Economic and Fiscal Outlook, the most recent issue of which was published March 2019. This reports the current and projected costs of these subsidies amongst other environmental levies (Figure 11).

Note that the Outturn column on the left is incomplete and has to be filled in by reference to Footnote 1, where we learn that the cost of the Feed-in Tariff in 2017–18 was £1.4 billion, which when added to the cost of the RO (£5.4 billion) and the CfD (£0.6 billion) gives a total of £7.4 billion. Adding the FiT the RO and the CfD projections, we can calculate the forecast renewable subsidy costs as shown in Figure 12.

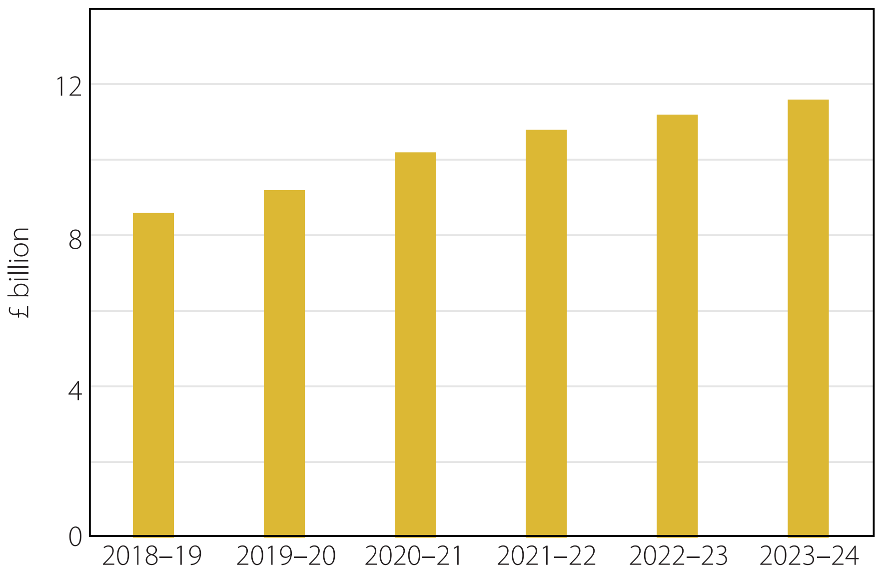


Figure 12: Forecast renewables subsidies to 2023–24.

Source: Office for Budget Responsibility, Economic and Fiscal Outlook – March 2019.

The current annual subsidy will be about £9 billion, and the grand total for the years 2017 to 2024 will come to nearly £70 billion.

These costs are recovered from the prices per unit of electrical energy (kWh) sold and thus the bills paid by all types of consumer: domestic, industrial, commercial and public sector. Consequently, about 30–40% of the total cost is recovered directly from household bills, because retail consumption typically comprises 30– 40% of total consumption in a year. In truth, the impact is likely to be slightly higher than the proportions suggest, firstly because industrial and commercial consumers can buy closer to the underlying wholesale price, and secondly because some intensive energy users have partial exemption from these costs, meaning that the burden is transferred to other consumers, including households. It is worth noting also that VAT is charged on these subsidy costs too, and domestic consumers cannot recover that cost. However, for the purpose of a general estimate we can ignore these details.

In 2017, domestic consumers accounted for about 38% of GB electricity consumption, and we can assume that this is approximately correct today. Thus, the direct impact on British household electricity bills is 0.38 × £9 billion = £3.4 billion.

There are about 26.5 million households in Great Britain, so the mean annual renewables subsidy impact on a GB household electricity bill is £3.4 billion ÷ 26.5 million = £129 per household per year.

However, this is not the end of the story. While the other 62% of the renewables subsidies are paid for in the first instance by industrial, commercial, and public sector consumers, these costs are obviously passed through to households in the costs of goods, services and general taxation. If a supermarket is compelled by policy to pay more for electricity to refrigerate milk it must recover that additional cost at the checkout. Of course, those companies with overseas customers could in theory pass on some part of that extra electricity cost to their consumers abroad but, given the intensity of international competition, that is unlikely to be a strong effect.

Consequently, it is reasonable to assume that the vast bulk of these costs are recovered domestically – in Britain – meaning that we can calculate a total 'cost of living' impact of the renewables subsidies by simply dividing total subsidies by number of households.

Thus, the total annual renewables subsidy impact on household cost of living is £9 billion ÷ 26.5 million households = £340 per household per year, of which about £129 a year is recovered directly from electricity bills and the remainder, over £200 a year, from increased costs of goods and services.

Given the scale and regressive nature of these impacts it is high time that the Department of Business, Energy and Industrial Strategy resumed publication of its formal estimates of the total impacts of policies – of which the direct subsidies to renewables are only part – on both gas and electricity prices. These figures were last published in 2014,[44] but then discontinued, many of us suspect because they were so embarrassing. At that time, the department calculated that in their central scenario for 2020 domestic household electricity prices (prices per unit, not bills) would be some 37% higher than they would have been in the absence of policies, and that prices for a medium-sized business would be some 62% higher. Future projections out to 2030 were equally disconcerting, and it is thus imperative to know whether government attempts to contain the costs of energy and climate policies are having any significant effect. Judging from the OBR forecasts the answer is clearly no. The public needs and has a right to see the details.

Coming clean about electricity prices

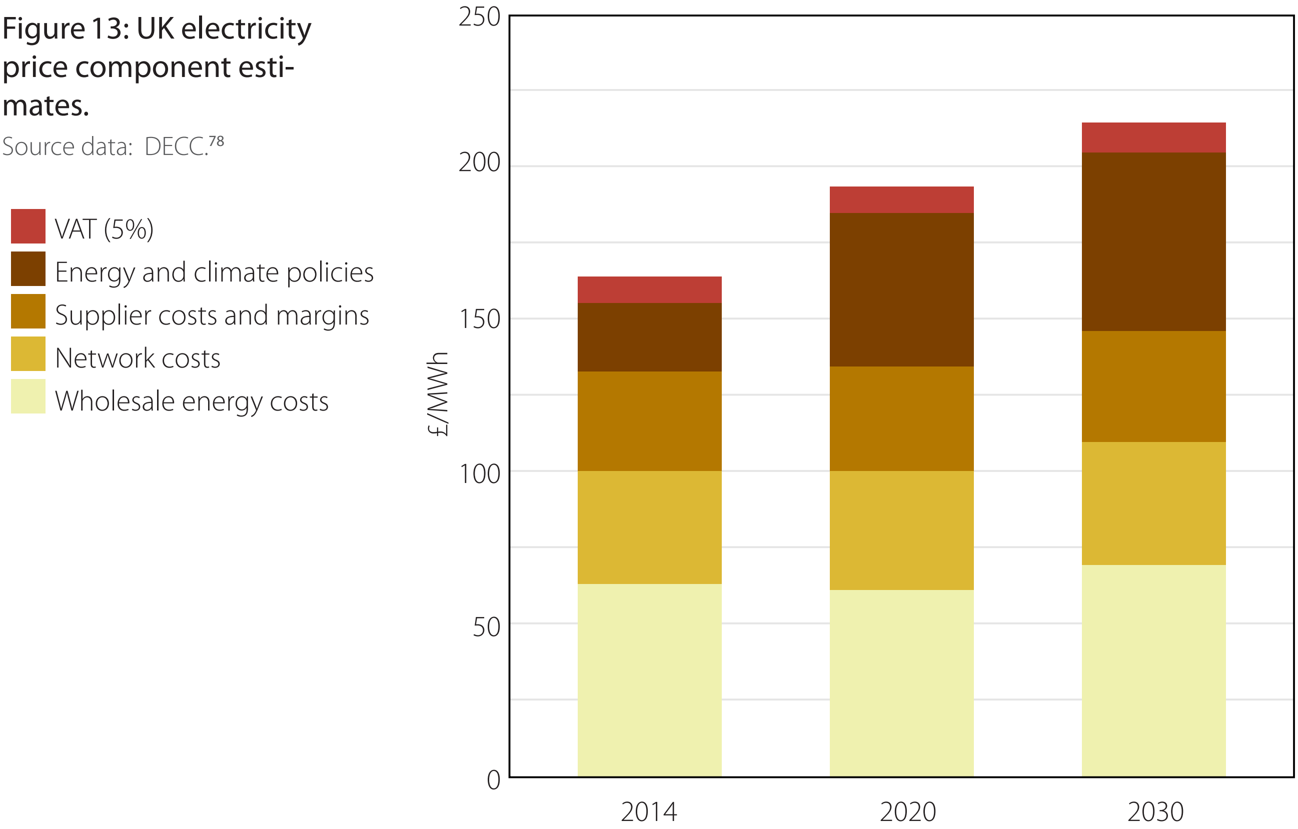
Britain's electricity suppliers are reported to be considering further increases in prices to consumers. Climate policies are largely responsible for such price increases, yet government is more than content to let private energy companies and their shareholders take the blame. Intoxicated with subsidies, the electricity sector has hitherto colluded in this obfuscation of causes, but the introduction of the domestic electricity price cap may change this situation, encouraging energy suppliers and indeed all businesses, to name government as the guilty party.

History provides very few clear lessons, but the records are tolerably clear that revenue collectors and tax farmers are always and everywhere loathed without reservation. This may be unfair, but it is a fact, a human universal. Why then did Britain's energy supply companies willingly accept the task of raising the necessary subsidies for renewable energy directly from their customers' bills? This in effect made these private companies covert revenue agents for the state, and so allowed government to hide the costs of energy and climate policies.

Anyone familiar with the industry will know there is no doubt that energy and climate policies are and have been for some time to blame for rising electricity prices, but the point bears repeating. Figure 13 shows the components of electricity prices charged to domestic consumers in 2014, and the projected figures for 2020 and 2030 in the Government's Central Fossil Fuel Price scenario. Energy and climate policy impacts are indicated by the brown section of the stacked bar.

Figure 13: UK electricity price component estimates.

Source data: DECC.[78]



It is obvious that those policies already accounted for a large fraction of the price in 2014, prices being 17% higher than they would otherwise have been. By 2020, policies were predicted to make prices 37% higher, and 41% higher in 2030. In fact, the method of presentation used in the figure somewhat understates the impact since a significant part of network costs are actually due to renewables, because of system balancing actions and grid expansion, and a slice of the VAT element also, of course, results from the policy costs. This is, then, a conservative presentation. Furthermore, the Central Fossil Fuel Price scenario is not necessarily the most probable. In the Low Fossil Fuel Price scenario, which appears to be materialising at present and may very well apply in 2030, energy and climate policies cause prices to be 42% higher in 2020 and 62% higher in 2030.

But even in this understated, conservative central scenario, in which fossil fuel energy costs are actually expected to rise, policies are still the dominant causal factor in the overall price increase up to 2030. Put more precisely, in the absence of policies, electricity prices would have been stable to 2020, rising from about 14p/kWh in 2014 to about 14.1p/kWh. In actual fact, prices stood at 16.4p/kWh in 2014 because of policies, and were expected to rise to about 19.4p/kWh in 2020. We appear to be on track.

While uncontroversial amongst specialists, these facts are sometimes obfuscated even by authoritative sources, such as the Committee on Climate Change (see for example, the *Energy Prices and Bills Report 2017*), and it has been a brave energy company that takes the risk of candour about the in-effect-tax component, as for example Ovo energy was last year.[46] Unfortunately, though perfectly correct, they have not been widely believed.

This is ideal for government, and is proving disastrous for electricity suppliers. Indeed, a very large part of the public perception that energy companies are greedy and ruthless results from the industry's short-sighted decision to allow itself to be used as the cat's-paw of climate policy.

The hazards of this situation must have been obvious to the main board directors concerned, but the temptation to collude was certainly extreme. The express-service renewables-target timetable required subsidies so large that the increased turnover and de-risked profit made the danger of bad public relations seem tolerable. The industry may well come to regret this lack of caution. A market sector debauched by subsidies, and already held in contempt by the public, will be in a very weak position to resist nationalisation by a radical socialist government. No one will step forward to protect a persecuted tax farmer, and the expropriators could be expropriated without any resistance, with the only public outcry being one of approval.

However, government may have unwittingly forestalled this outcome, by introducing the domestic electricity price cap,[47] a decision that could force an otherwise anaesthetised and lethargic industry into action. The uncertain, medium-term risks of a toxic public image and possible nationalisation may be pushed to one side by preoccupied executives, but an immediate crisis in revenue has to be addressed without delay. And the price cap genuinely does present a problem to the electricity supply industry. Having accepted the task of delivering the renewables policies, the industry is now being inhibited from passing the consequent additional costs on to their domestic consumers via rising prices. The sums are not small. The Office for Budget Responsibility estimates that the renewables subsidy costs already amount to about £8.6 billion per year in 2018/19 and will rise to about £11 billion a year by the end of the current price cap period in 2023.

Such steadily increasing policy costs can only be recovered from consumers, and it is therefore probable that, blocked in one direction, suppliers will and must start to increase prices where the cap does not apply, for example prices charged to households choosing fixed term deals, and, much more probably, prices to industrial and commercial consumers.

Since those business consumers will necessarily pass their additional electricity costs on to households in the cost of goods and services, and also in downward pressure on wages and rates of employment, it is debatable whether there will be any net benefit at all from the domestic price cap. What was an electricity cost issue will become another aspect of the general cost of living problem. Indeed, since it is likely that commercial consumers will prefer to pass costs on via those of their products where demand is most inelastic, it is likely that those whom the energy bill price cap sets out to benefit will be worst affected. Basic goods and services, naturally enough, make up a large fraction of the expenditure of a low-income household.

None of this is surprising. The price cap was reluctantly introduced by a weak government and against firm advice from economists, so regressive misfires can hardly be called 'unforeseen consequences'. It was obvious that the price cap would ultimately be bad for consumers in very many ways. However, there is a silver lining to this debacle in that energy companies may now be encouraged to speak out with vigour about the extent to which state policy rather than market fundamentals is responsible for consumer pain.

They might, for example, self-protectively put their weight behind arguments to persuade government to resume the publication of *Estimated Impacts of Energy and Climate Change Policies on Energy Prices and Bills*, the last release of which, in 2014, is still by far the most informative guide in the public domain. Since the discontinuation of this crucial dataset, government action to reduce energy sector emissions has been flying in a condition of almost complete radio silence in regard to consumer costs. This is unacceptable.

Making do with the information we have, it is obvious from the 2014 data – for example the estimates displayed in the chart above – that consumers should have benefitted over the last few years from electricity prices that were low and stable, whereas in fact prices have increased so much that they have become sufficiently salient to consumers to give specious grounds for a mandatory cap.

With still larger policy-driven price increases in prospect, energy suppliers were scrambling to raise their tariffs before the price cap came into effect on the 1st of January 2019, and the blame game was already starting.[48] Will the energy companies allow government to get away with this again? Since the price cap clearly shows that they cannot trust their partner in crime, perhaps they will now turn Queen's evidence and speak up on behalf of the public. If they do so, they might find themselves in good company. Industrial and commercial *consumers* also have an interest in ensuring absolute transparency about energy policy costs. While energy is typically under 10% of the total annual costs of a business, the predicted increase in electricity prices is large even without the burden-shifting probable as the result of the price cap, and such price increases will bite deeply into already very thin profit margins. *Estimated Impacts* reported that, even in the conservative Central Fossil Fuel Price scenario, businesses would see electricity prices rise by 50–60% by 2020 because of policies, while in the Low Fossil Fuel scenario prices are predicted to rise by between 60% and 114%. These striking increases will inevitably be passed through in the costs of goods and services. Unless they are told otherwise, consumers will regard this as yet more evidence of 'Rip-Off Britain'. Private businesses have every reason to make sure this does not happen.

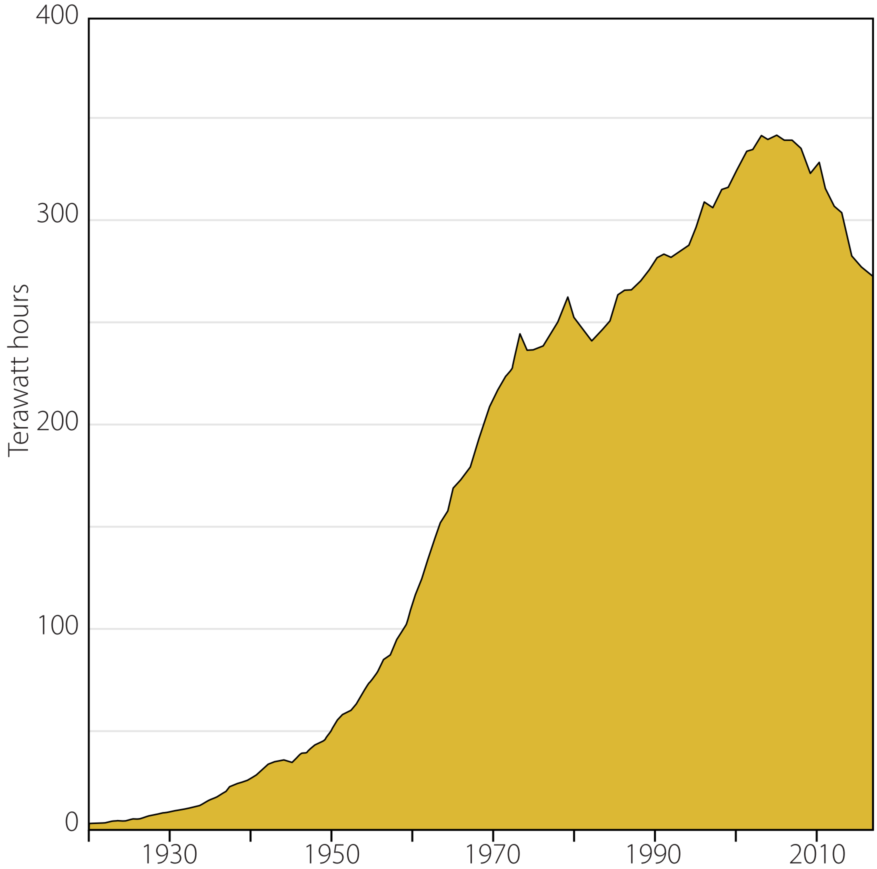
Fuel poverty and electricity policy costs

New analysis from the UK government shows that households are heating their houses less than is required to meet the levels thought necessary to deliver comfort and health. Those on lower incomes are 'under-consuming' by a larger margin than those on higher incomes, with only the top richest decile consuming more than the estimated requirement. It seems probable that increased prices for electricity are rationing the poor out of the heat market.

Electricity demand in the United Kingdom has been falling for about fifteen years, with consumption in 2017 at levels last seen in the 1980s (Figure 14).

Figure 14: UK electricity supplied, 1921–2017.

Source data: BEIS.[79]



The fall is so large and so closely correlated with the introduction of policies increasing electricity prices – note that demand falters in the middle 2000s shortly after the UK introduced its Renewables Obligation subsidies in 2002 – that there is a lurking suspicion that *price rationing* must be at least an element in any plausible explanation, certainly in more recent years. Even if we allow that the early onset of the 2008 crisis is probably responsible for the initial decline in electricity consumption, the lack of a subsequent recovery in demand might well be largely attributable to the rising burden of renewable electricity subsidies (about £9 billion a year at present) and their associated system balancing and grid costs (Balancing Services Use of System costs, are now £1.3 billion per year as compared to about £300 million a year in the early 2000s).

In regard to the non-domestic sector, there is little real disagreement that this decline in electricity consumption can be confidently attributed in large part to deindustrialisation caused by the export of many production processes to jurisdictions – principally China – with lower costs, electricity amongst them. This is an EU-wide effect, with industrial electricity prices in the EU28 being 50% higher than those in the G20.[49]

But the domestic correlate of this effect, in relation to household consumption, is more controversial. Apologists for the UK's policies tend to argue that the widespread adoption of efficient conversion devices, such as LEDs and better white goods in areas where demand is not particularly elastic, have cut electricity demand without reducing consumer benefit. But analysis bearing directly on this question is in short supply. Fortunately, as part of its monitoring of fuel poverty, the UK government has recently undertaken an examination of energy consumption at the household level that throws some welcome light on the question.

The March issue of *Energy Trends,* the statistical bulletin of Department of Business Energy and Industrial Strategy (BEIS), contains an article[50] that puts actual household energy consumption alongside that predicted by the fuel poverty models as necessary to achieve comfortable and healthy levels of heat.

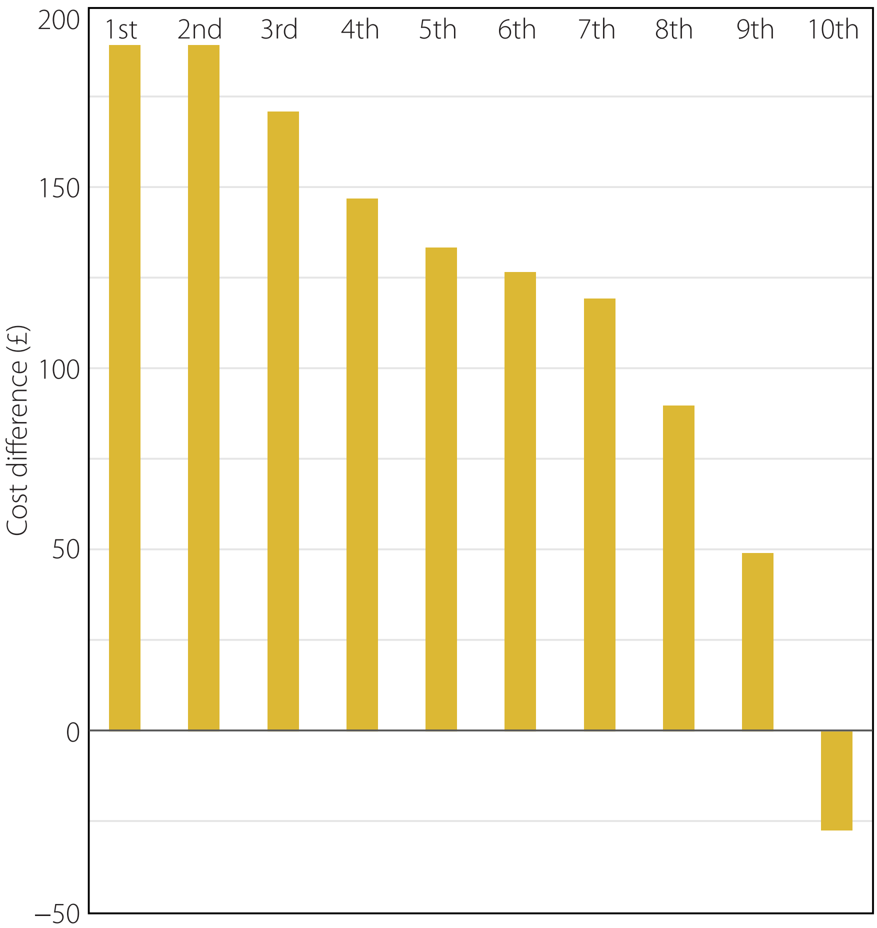
The government's analysis finds that 69% of households had a theoretical level of consumption that exceeded their actual consumption, the average underspend being about £133 per household per year, or 9.9% of the expected spending. This tendency is stronger in relation to those households classed as 'Fuel Poor', which were underspending by £319 per household per year (19.9%), as opposed to the 'Not–Fuel Poor', who were underspending by £110 (8.6%) per household per year.

Suspicions that this might result from a known bias in the model, which may overstate requirements,[51] are to a degree dispelled by the fact that the distribution over income bands is uneven, with those on low incomes much more affected. Indeed, the underspend decreases as household income rises, and those households that spent more on energy than the model predicted also had incomes 21% higher on average than the rest of the sample. Figure 15, redrawn from the study, illustrates the distribution. It is quite clear, as BEIS itself concludes, that the effect of underspending is 'strongly linked to income'. Low-income households underspend on energy to a greater degree than higher income households.

Furthermore, fine-grained analysis reveals that 'households with children had the largest average under-consumption' and that, generally, 'lower income households with dependants are potentially more likely to under-consume than other households',[52] with this effect particularly marked for fuel-poor households.[53]

Some would argue that these effects are consistent with the view, which I emphasise is not expressed in BEIS's paper, that such underspending, particularly in the lower deciles, is largely the ef-

Figure 15: Estimated UK household underspend on energy by income decile.
Source: BEIS.[80]



fect of price-rationing. In other words, energy prices are sufficiently high to force consumers to trade off their wish for heat against competing demands for that income, with evidence of the trade-off being, inevitably, particularly marked in the lower income deciles. However, given the known bias in the model itself, the underspend recorded for the middle- and higher-income deciles is perhaps less significant and our attention should be focused on the causes underlying low energy consumption by the poor. Why are they underspending by so much?

One possibility is that low-income households tend to use electric heating. The regulator, Ofgem, reports that of the 26 million households in Great Britain, about 22 million use natural gas for heating, with 2.2 million of the remainder using electricity. Ofgem also indicates that electrically heated households tend to be of lower income, with around one third of electrically heated households in receipt of an annual income of under £14,500 per year.[54] That is not surprising, since many electrically heated households are flats, and 25% of all flats in Great Britain are electrically heated, as compared to only 4% of houses. The rented sector, of course, is used heavily by those on lower incomes. Indeed, there is some reason for thinking that the proportion of flats using electricity for heating may actually be rising, as non-condensing gas boilers on shared flues reach the end of their lives, and cannot be replaced with the now mandatory higher-efficiency condensing boilers since the flue gases are too cool to exit the flue safely. In such cases relatively expensive electric heating is the only feasible option.

It follows, therefore, that the 2.2 million electrically heated households are very probably concentrated in the lower-income deciles, precisely where BEIS's study has found greater levels of underspending on energy.

That should be of concern to the Government, since energy and climate policies have a much greater effect on the price of electricity than on the price of natural gas. In 2014, BEIS's predecessor, the Department of Energy and Climate Change, estimated that by 2020, policies would be making electricity prices to households about 36% higher than they would be in the absence of policies, while the effect on gas prices was to increase them by only 6%.[55]

We can consequently conclude that it is very likely that the significant levels of underspending on energy reported for lower-income households are caused in significant part by electricity price increases resulting from energy and climate policy.

With that in mind, I wrote to BEIS asking whether their dataset could identify the electrically heated households and so evaluate the hypothesis that the reported 'under-consumption', particularly of the lower income deciles, was correlated with and in part caused by their use of electric heating. The statistician responsible informed me that the question had indeed been examined, but, unfortunately, the dataset did not distinguish clearly between non-gas households that used electricity only and those that used other fuel types for heating as well. Consequently, the department 'did not have a reliable enough sample to accurately test the difference in theoretical and actual consumption between gas heated and electric heated dwellings.' I see no reason to doubt this explanation, but it is obviously a limitation in the government data that should be rectified promptly.

Even without that information, we can be confident that higher electricity prices, known with certainty to result from energy and climate policies, are very probably making heating unaffordable for those on lower incomes, and that *the Government appears to be price rationing the poor out of the heat market in order to reduce emissions*. But so far from having second thoughts, the administration is, as the Chancellor told us in his Spring Statement, planning to extend price rationing to still more households, with its Future Homes Standard 'mandating the end of fossil-fuel heating systems in all new houses from 2025'.[56] This could well, as Mr Hammond said in his speech, and apparently without irony, deliver 'lower carbon' and 'lower fuel bills too', but only through price-coerced underconsumption.

The decline and fall of Ofgem

The first act of Mr Jonathan Brearley, the new CEO at the UK electricity and gas market regulator, Ofgem, has been to publish a Decarbonisation Programme Action Plan*, a document that demonstrates that the regulator is no longer independent and is now an integral part of the climate change policy delivery mechanism and will consequently do nothing, beyond paying lip-service, to protect present consumers from the costs of the 2050 Net Zero target. This confirms concerns that, as a long-term Whitehall policy insider and responsible in part for both the Climate Change Act (2008) and Electricity Market Reform, Mr Brearley was not an appropriate choice to lead the regulator.*

In October 2019, Ofgem announced that Jonathan Brearley, its own Executive Director for Systems and Networks, would be succeeding Dermot Nolan as Chief Executive, taking over at the end of February 2020.[57] Mr Brearley's Whitehall career is practically a history of modern British climate change policy. From 2002 to 2006 he served as 'Head of Team' in Tony Blair's Prime Minister's Strategy Unit (PMSU).[58] The PMSU was at least in part responsible for the *Energy Review* of 2002, and for *The Energy Challenge* study of June 2006, amongst other things.[59]

From July 2006 until September 2009, Mr Brearley worked as Director of the Office for Climate Change, an offshoot of the Department of Environment (DEFRA) that formed the administrative nexus drawing together six other departments for work on the Climate Change Act (2008).

This experience led to a further appointment in late 2008 in Gordon Brown's new Department of Energy and Climate Change (DECC), where he became Director of Energy Strategy and Futures, and then Director of Electricity Markets and Networks. In this latter position he is said to have 'led the delivery of the Governments' Electricity Market Reform…programme', the programme which introduced Contracts for Difference, the subsidy scheme introduced to replace the Renewables Obligation.

Mr Brearley continued to serve under the Conservative/Liberal Democrat Coalition Government, but in 2013 he resigned visibly and dramatically from DECC,[60] with the *Independent* newspaper reporting a source to the effect that Brearley was 'not happy… DECC is working to improve the investment climate and the Treasury is stopping it'.[61]

For a short while after his resignation he ran his own consultancy, Brearley Economics Ltd, the clients of which are not publicly known, which was incorporated in March 2013, just before he left DECC, and was voluntary liquidated in 2016–2019 prior to his return to Whitehall in April 2018 with a position in Ofgem,[62] as Executive Director for Systems and Networks, a position he held for only eighteen months before being promoted to the top job of Chief Executive Officer in October 2019.

It must at the least be questionable whether such a person was a suitable choice to act as the CEO of a regulatory body intended to protect the consumer interest. The majority of Mr Brearley's civil service career has been marked by close and committed involvement in the creation of climate policies that impose high costs on consumers, yet he is now entrusted with overseeing the regulation of the markets just as his own policies, now augmented by the Net Zero target, come to maturity. He can surely be neither objective nor independent.

Did no-one on Ofgem's board ask themselves whether this candidate might have a conflict of interest? Did they ask, for example, whether Mr Brearley was in reality likely to side with the consumer against the costs of instruments which he himself had a very prominent role in creating, even, it seems, resigning in protest over Treasury attempts to rein in those costs? If they did so it made no difference to their choice.

From the point of view of the regulator's wider reputation, this appointment is like to prove a mistake, and, until Mr Brearley is replaced, Ofgem will, even in the eyes of only moderately suspicious members of the public, lack any credibility as a sincere and scrupulous guardian of the consumer interest.

Confirmation that these concerns are not merely theoretical can be found in Mr Brearley's first act as CEO, the publication of the *Ofgem Decarbonisation Programme Action Plan*, which was released on the 3rd of February 2020

This document is in substance only a subservient echo of the Climate Change Act and its successor the Net Zero target. Indeed, Mr Brearley's own Foreword tells us as much:

> It is vital that as the regulator we are taking the steps to enable and encourage the decarbonisation of energy, playing our part in helping the government achieve its ambition…This action plan is just the start of Ofgem's drive to play our role in achieving net zero by 2050.[63]

No independent and consumer-oriented regulator could have written in this way.

Moreover, the lip-service to 'low-cost decarbonisation' is revealed for what it really is by the subtle reference, easily overlooked, to what Mr Brearley refers to as Ofgem's 'principal objective', namely, 'to protect both current and future consumers',[64] a point reiterated in the main text of the document:

> In line with Ofgem's principal objective we will balance the benefits to future consumers of greenhouse gas reductions alongside the potential costs to current consumers.[65]

Those words will ring an alarm bell for any student of Ofgem's history. As I noted in 2017, the Utilities Act of 2000 had described the overarching principal objective for energy regulation as *the protection of the interests of existing and future consumers, wherever appropriate by promoting competition*.[66] This was a lucid and unconstricting brief. However, the Energy Act of 2010[67] amended this principal objective by defining 'interests' thus in two separate paragraphs[68] referring to gas and electricity:

> Those interests of existing and future consumers are their interests taken as a whole, including–
>
> (a) their interests in the reduction of gas-supply/electricity supply emissions of targeted greenhouse gases; and
>
> (b) their interests in the security of the supply of gas/electricity to them.

This change was of enormous importance, since an increasingly large part of the charges on the consumer were (and still are) the result of climate policy. In effect, the revision to Ofgem's principal purpose made them unable to comment on the imposition of cost increases resulting from measures to mitigate climate change.

Mr Brearley's Ofgem embraces this restriction with vigour. Since present consumers are finite in number, and the nebulous definition implicit in the term 'future consumers' creates an infinite set, no balancing calculation can favour present consumers unless there is a discount rate, and of this there is no mention either in the Act of 2010 or in Ofgem's commentary. But real consumers do discount the future, and this is not necessarily selfish; if parents, for example, failed to discount in order to maintain their own lives, there could be no future generations to be worried about.

The lack of discounting thus puts Ofgem on a collision course with real consumer, real human behaviour. Ofgem's interpretation of the 2010 Act means that they will put only the weakest of brakes on the imposition of climate change cost burdens. Present consumers now have little or no voice.

Any hopes that Ofgem might in the future attempt to reverse this weakening of its powers – made of course when Ed Miliband was Secretary of State and Mr Brearley was a senior director in DECC – must now be abandoned since Mr Brearley himself is in charge of Ofgem. Until there is a major overhaul this will be the *status quo*.

The defence that will be offered, of course, is that immediate high expenditure is simply prudent and precautionary. Ofgem writes in its *Action Plan*:

> We are clear…that investing in the short term will save money in the medium and long term.[69]

The misuse of the phrase 'I/we am/are clear' in political declarations is by now a notorious give-away, and it is regrettable to find it in the statement of a regulator. Emphatic assertions of faith may pass with politicians, but are surely impermissible for an objective body entrusted with quasi-judicial oversight. From such an institution the public has every reason to expect careful calculation and argument, not unsupported fervency.

A great deal depends on this, for the short-term investments about which the regulator claims to be so clear are not of a minor order. Mr Brearley's new model Ofgem blithely reports the Committee on Climate Change's estimate that power sector investment:

> may need to increase to around £20 billion (in 2019 money) per year by 2050, to cover 'investment in renewables, firm low-carbon power, CCS, peak power and networks (including transmission and distribution).[70]

The cumulative sum, in fact unpublished, will be very large indeed. For comparison, the document itself notes that a mere £10 billion was spent between 2013 and 2017.

Similarly, in regard to heating, Ofgem now reports without concern the CCC's estimate that switching to low-carbon heating 'will require annual investment by 2050 of around £15–20 billion (in 2019 money), up from just £100 million in 2018'.[71]

Faced with proposals for such vast expenditure, an objective regulator would require stringent cost–benefit analysis and justification, but under Mr Brearley that not will happen, as the *Action Plan* explains:

> 'The challenges of net zero are stark and require us to step up our efforts to meet them. As energy regulator, we can create the regulatory framework to enable the appropriate investment, and help direct that investment where it is needed.[72]

There is only one way in which this can be understood. The ends are taken to justify the means, and Ofgem will collaborate with government to coerce the consumer into delivering a rate of return sufficiently high and secure to motivate investment.

As a supplementary reinforcement for this position, Ofgem claims that the costs of the preferred energy supply, renewables in general and offshore wind in particular, are already very cheap:

> The dramatic reduction in offshore wind costs demonstrates that in the long term, low carbon energy can be cheaper than traditional fossil fuels.[73]

> Few commentators anticipated the recent rapid reductions in the cost of wind and solar power.[74]

As a matter of fact, not everyone is convinced that there is significant substance to these apparent cost reductions, with some doubting, for example, that the capital costs of offshore wind, for example, have fallen much if at all. Hughes, Aris and the present author[75] and Hughes[76] reviewed offshore wind capital cost data and detected no dramatic fall, a finding that has been replicated by a recent study of audited wind farm company accounts by economists at the Aberdeen Business School of Robert Gordon University.[77] The authors of the latter paper appear broadly sympathetic to the renewables agenda, but nevertheless write:

> The most recent CfDs were awarded at a price (in 2012 terms) of £57.50/MWh, while the analysis here shows that modern wind farms typically have a LCOE of c. £100/MWh. Although… the LCOE and strike price are only the same in a zero-inflation world, it is nonetheless clear that very significant reductions are required to wind farm costs to offer economic projects in the context of current strike prices.

Of this data-grounded concern, Ofgem says not a word, and instead simply repeats the self-serving industry propaganda about falling costs. A truly independent regulator would not have filled up the cry in this way. On the contrary, it would instead have asked if the bids were too good to be true, and whether the CfD system were being exploited to obtain mere options for development, thus gaining market position and inhibiting competition. But Mr Brearley is surely not disengaged in this matter, since he himself oversaw the introduction of Contracts for Difference as part of the EMR package. Being only human, it would be remarkable if he did not have a personal interest in declaring CfDs a success. He may even be quite blind to the possibility that things have gone wrong.

The publication of Ofgem's *Decarbonisation Programme Action Plan* marks the final degradation of the United Kingdom's electricity and gas market regulator. The process begun by the revision of Ofgem's objectives in the Electricity Act of 2010 has been completed in 2020 by the appointment of Mr Jonathan Brearley, a long-term Whitehall climate policy insider who has interests that appear to conflict strongly with those of the consumer. Reform of the Office of Gas and Electricity Markets has long been regarded as needed; it is now essential.

Notes

1. https://data.nationalgrideso.com/balancing/bsuos-monthly-forecast?from=0#resources.

2. https://www.nationalgrideso.com/news/managing-reduced-demand-electricity-what-our-new-odfm-service-and-why-do-we-need-it.

3. https://www.nationalgrideso.com/industry-information/codes/grid-code-old/modifications/gc0143-last-resort-disconnection-embedded.

4. https://www.ofgem.gov.uk/system/files/docs/2020/05/gc143_d.pdf.

5. https://www.ref.org.uk/constraints/index.php.

6. CUSC Modification Proposal Form: CMP345: Mod Title: Defer the additional Covid-19 BSUoS Costs. https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp345-defer.

7. CMP345, p. 8.

8. https://www.theguardian.com/business/2020/may/19/ovo-energy-cut-jobs-sse-coronavirus-lockdown.

9. https://www.ofgem.gov.uk/ofgem-publications/163442.

10. https://data.nationalgrideso.com/balancing/bsuos-monthly-forecast/r/a_note_on_our_bsuos_updates_published_15th_may_2020.

11. The large rotating masses of traditional power stations represent a store of energy – inertia – that helps slow down the spread of the effects of a system fault, giving managers vital time to bring alternative generation online.

12. Embedded generators do not supply the transmission grid, but instead are 'embedded' in the distribution grid, closer to consumers.

13. See p. 15.

14. Summer Outlook, p. 14.

15. https://www.nationalgrideso.com/insights/system-operability-framework-sof.

16. https://www.nationalgrideso.com/balancing-services/transmission-operational-forum.

17. National Grid, System Operability Framework: Impact of Declining Short Circuit Levels (December 2018), p. 1.

18. National Grid, System Operability Framework: Whole System Short Circuit Levels (December 2018), p. 2.

19. National Grid, System Operability Framework: Impact of Declining Short Circuit Levels (December 2018), p. 1.

20. National Grid ESO, System Operability Framework: Impact of Declining Short Circuit Levels (December 2018), p. 3.

21. So-called Balancing Service Use of System (BSUoS) costs.

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The Global Warming Policy Foundation is an all-party and non-party think tank and a registered educational charity which, while openminded on the contested science of global warming, is deeply concerned about the costs and other implications of many of the policies currently being advocated.

Our main focus is to analyse global warming policies and their economic and other implications. Our aim is to provide the most robust and reliable economic analysis and advice. Above all we seek to inform the media, politicians and the public, in a newsworthy way, on the subject in general and on the misinformation to which they are all too frequently being subjected at the present time.

The key to the success of the GWPF is the trust and credibility that we have earned in the eyes of a growing number of policy makers, journalists and the interested public. The GWPF is funded overwhelmingly by voluntary donations from a number of private individuals and charitable trusts. In order to make clear its complete independence, it does not accept gifts from either energy companies or anyone with a significant interest in an energy company.

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