Our Electricity Market - The Flaw and the Solution

Summary

The current arrangements for electricity production are not working properly. Prices are unnecessarily high and volatile and the lay person is confused. Why, for example, do “green electricity tariffs” rise when gas prices go up, even though renewables don’t use gas? These concerns make new investment difficult and, unless radical changes are made, threatens the target of complete decarbonisation of the UK’s power sector by 2035.

The root cause of the problem is the competitive wholesale electricity market. This was created in 1990 as the electricity supply industry in England & Wales was liberalised and privatised. At the time, no-one recognised the full implications of the fact that electricity cannot be stored cheaply in bulk. In the following, I will explain how this creates volatility in electricity prices and increases the cost of finance. Volatility is likely to increase further as the existing fleet of fossil fuelled power stations is replaced by renewable and other forms of non-fossil power.

However, I will show that this volatility may be avoided by re-allocating the risks inherent in electricity generation. In place of the present wholesale market, I propose that an Exchange should be created. This Government-owned entity would be responsible for purchasing power from generators (owned by the private sector) under long term contracts. The Exchange would sell the power to Suppliers who, as now, would sell on to customers, over the existing networks.

There are many benefits that would arise from this radical restructuring. The Generators and Suppliers’ profits would no longer be driven by their trading divisions. Instead, their profits would be directly related to the skill with which they carried out their operations. In addition, it would enable some central coordination of the transformation of the electricity industry as it decarbonises, facilitating planning and investment in both generation and the networks.

Why the wholesale market in electricity was created

During the 1980s, general dissatisfaction with the performance of the nationalised monopolistic utilities led to the reorganisation of the electricity industry in England & Wales under the Electricity Act (1989). Coming after the privatisation of British Gas, when the company’s monopolistic structure was maintained and performance did not improve, the Conservative Government was determined to introduce competition to the electricity market.

The vertically integrated nationalised electricity supply industry of England & Wales was accordingly split in 1990 into a number of new businesses and privatised during 1990 and 1991. The Scottish industry was privatised in a similar fashion the following year. Previously, the publicly owned Central Electricity Generating Board (CEGB) produced all the electricity in England & Wales and transported it through its wholly owned National Transmission Grid to twelve separate regional Area Boards who delivered electricity to customers in their particular regions.

Monopolistic provision and pricing

Before 1990, these Area Boards purchased electricity from the CEGB and sold it over their local distribution networks to customers’ premises. The industry’s prices were set on a “cost plus, take it or leave it” basis. In other words, each year, the industry estimated its costs, such as fuel, manpower and materials, added allowances for depreciation and return on capital (2.5% after inflation) and arrived at a total revenue. The CEGB forecast the revenue it would need to cover its costs and provide a return. It published a Bulk Supply Tariff which set out the prices each Area Board would pay during that year. The Area Boards had no option but to buy this power from the CEGB. Similarly, customers had no option but to buy electricity from their local Area Boards, since there were no other providers of power. The Area Boards could generate their own power, but very few chose to do so.

Restructuring

The restructuring of the industry in 1990 was designed to introduce competitive forces wherever possible. Prices were to be set by the market where competitive forces were strong or by regulation where competition was not feasible or had insufficient time to develop. Decisions on when and where power stations should be built and what type of fuel they should use, for example, previously taken by the CEGB, would be left to "the market". Accordingly, the businesses created in 1990 and their price regulation were as follows:

Table 1

Generation	Production of power in bulk at large power stations.	Wholesale prices set by competition between Generators selling to Suppliers. Generators paid the Transmission company for using the network.
Transmission	Transportation of electricity in bulk at high voltages from the power stations to the centres of demand. The coordination of power station operation	Price caps set by regulation.
Distribution	Transportation of electricity from the high voltage networks to customers' premises	Prices capped by regulation.
Supply	Purchase of power in bulk and its sale to customers	Prices set by competition. Suppliers paid the Transmission company and the distribution companies for using the networks.

The creation of separate "Supply" businesses and the new wholesale power market were the major innovations of the 1989 Energy Act. Nowhere else in the world had power been traded at the wholesale level in this way, nor could so many customers switch to alternative Suppliers.

In this new world, rather than prices being set "top down" by Government, Suppliers entered into contracts with Generators for amounts of electricity (MWh) at specified times and prices. They added the network costs, which were subject to price controls, included a profit margin and set their tariffs for customers accordingly.

It was anticipated that generators would build new power stations whenever it appeared to be profitable. This was expected to be a consequence of old generating stations retiring and new, cheaper, technologies and fuels becoming available, such as gas. In addition, as demand for electricity grew closer to the available capacity, prices should rise, and new generation would be built. In other words, it was for the market to decide when and what to build. The new arrangements effectively relied on the profit motive, rather than any legal obligation, "to keep the lights on".

This reliance on the profit motive was a grave mistake. Electricity is not like other commodities, such as oil, pork bellies or cotton, because it cannot be stored cheaply. The consequences of this fact started to become apparent in the 2000s when looming shortages of generating capacity became apparent. Governments have since attempted to tamper with the wholesale electricity market but without addressing this fundamental problem. In the following, I explain why a competitive wholesale electricity market is incapable of providing secure and affordable power.

Wholesale electricity markets

Generators sign contracts with Suppliers to sell power at specified times and prices. If, in any particular half hour, a generator's obligations under its contracts with Suppliers differs from its actual production, the surplus, or deficit, is made good by some commercial arrangement. Similarly, if a particular supplier's customers consume more, or less, power than the Supplier has purchased through their contracts with Generators, the difference is made good and priced according to this trading arrangement. The way in which these surpluses and deficits are priced has evolved over the years[1], but these trading arrangements simply accommodate the unique features of electricity, namely:

- power is difficult to store, so there is a need to match generation with demand at all times, and
- the inability to differentiate between sources of generation, making electricity a "perfect" commodity.

In all other aspects, electricity may be considered as a commodity, so its price behaviour should be, and indeed has been, similar to that of other commodities.

The ability for customers to switch Supplier puts pressure on Suppliers to ensure that they offer competitive prices. The more competitive the Supply market became, as customers learnt how to switch to alternative Suppliers and commercial customers searched for good deals, both Generators and Suppliers became less inclined to conclude long term contracts. Neither side wanted to be exposed to the risk of being "out of the market". As a consequence, the market has been dominated by contracts of just one year's duration or shorter.

Prices in wholesale electricity markets

Demand for electricity varies all the time. Consequently, various power stations are turned up and down during the day. This means that there will almost always be spare capacity available. Due to the competitive nature of the British power system, this implies that the half hourly prices will reflect the marginal cost of production of the most expensive unit required to meet demand at that time unless there is, or appears to be, a shortage of capacity, in which case prices will rise dramatically. The pricing behaviour is therefore likely to lead to a series of long "troughs" when there is excess capacity. This will be interspersed with price spikes when demand approaches available capacity. If we assume, for simplicity, that all forms of production have similar variable costs, then all the producers will only be profitable during these times of shortage, since these will be the only times

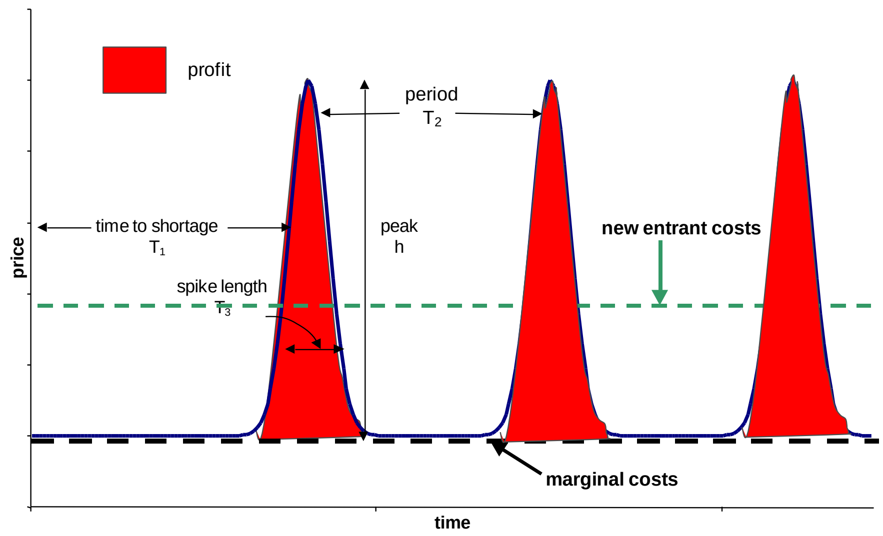
[1] Further details of this trading arrangement are provided in the Appendix.

when prices would be able to rise above marginal costs. This is depicted in Figure 1 below. The magnitude of the resulting price rise (h) will depend on many factors, such as the time required to build and commission new capacity, the rate of retirement/exhaustion of generation, the rate of demand growth, the short-term price elasticity of demand and the cost of new generation and profit a producer would require before it commits to construction. The more uncertain the future price outlook, the higher return the producer will require and will wait until prices are higher before releasing, or building, new capacity. The duration of the peaks (T_3) is likely to be very short, say 6 months at most, as larger customers respond by managing load or peaking generators will be built, which are cheap to build but expensive to operate.

When there is not a looming shortage, generators would only cover their operating costs and not provide a return to capital, as indicated by the "new entrant" cost line. I appreciate that the assumption of identical generators is very simplistic. Nevertheless, gas fired power stations currently represent most of the marginal generation on the British system and their operating characteristics are reasonably similar. So I believe the conclusion that returns will only be generated at times of shortage is close to reality for most of the fossil stations.

FIGURE 1

Prices in a fragmented competitive market



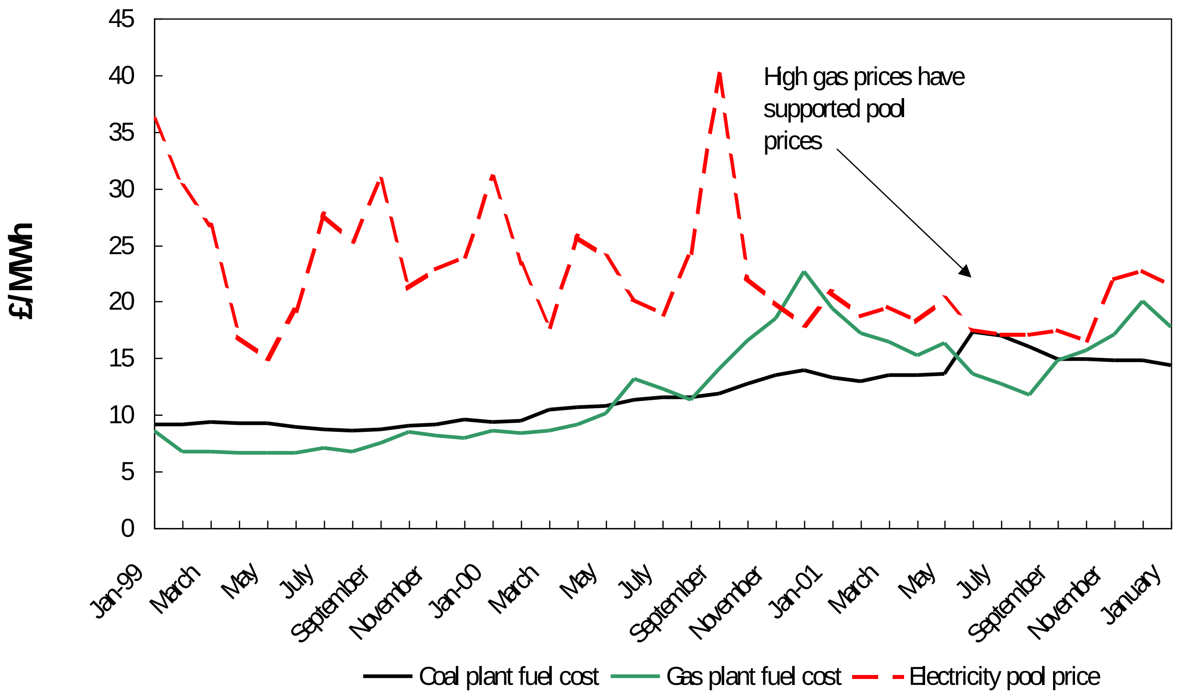
This pricing behaviour poses a very severe problem for potential investors in electricity generation. Why take the risk of building a new plant when, once the plant is commissioned, prices in the wholesale market could collapse to marginal cost? For the reasons explained above, a generator is unlikely to convince a Supplier to agree to a multi-year fixed price contact. What happens if there is a delay in commissioning and others build new plant before them and so miss the price "spike" completely. The risk will be magnified in the future since most of the generating capacity required to meet the net zero target, i.e. large scale off-shore wind, nuclear and schemes involving carbon sequestration, require long lead times and are capital intensive.

Actual behaviour

After the market in England & Wales was restructured 1990, the market was dominated by National Power and PowerGen who, together, owned the vast majority of fossil stations in England & Wales. These companies could and did set prices above the cost of new entry because they could control the market. They started to replace their existing coal and oil-fired power stations with gas-fired plant but others, attracted by the high prices, also built new gas stations. Consequently, in early 2001, the two generators had lost so much market share that they could no longer control market prices. Prices collapsed to marginal costs, as shown in Figure 2 below. The red line (electricity price) fell after 2001 to the cost of producing electricity either by gas (green) or coal (black). Prices have since remained in line with marginal costs apart from a short period in 2008 when there were concerns that there was not enough generation capacity available.

FIGURE 2 1999-2002

Prices in British Wholesale Market



The Interventions

Concerns about the risk of there being insufficient generation as environmental legislation forced the closure of older fossil generating units led to a looming shortage of capacity. Generators were not coming forward to build new plant. Indeed, their behaviour exposed a failing in the belief that, to incorrectly paraphrase Adam Smith, markets deliver the lowest cost solution. In the real world, it appears that markets tend to deliver the most easily financeable options. In the case of peak capacity, the easiest option for generators was to sit on their hands. After all, a portfolio generator is under no obligation to "keep the lights on" and, in addition, would be able to enjoy any "peak" as its existing plant would enjoy higher profits as prices rose.

As a consequence, the Government introduced the Energy Act (2013). This created two Government-owned entities to stabilise the revenues of particular generators by collecting additional funds from all customers through levies. These contracts were awarded by auction and supported forms of new non-fossil generation and capacity of any complexion. The non-fossil contracts, called Contracts for

Differences (CFDs) specify the “strike price”, in £/MWh, at which a generator undertakes to build so many MW of new generating plant. If the wholesale market price turns out to be lower, then the difference is collected from customers through a levy. However, as explained below, this mechanism is likely to become unworkable as the proportion of plant with low marginal cost increases. In other words, the current regime of a wholesale market with various additions (or sticking plasters) is not sustainable, in the temporal sense.

Where markets do not deliver effectively

The two mechanisms introduced by the Electricity Act (2013) have been successful, in that there has been sufficient capacity to meet demand, different forms of renewable generation have been commissioned and the prices of subsequent contract auctions have fallen. Effectively, the Government now decides when and what type of generating plant to build. This is not a transparent process and is a far cry from the original intention of the restructuring in 1990 but I believe it was inevitable. The problems arise because they relate to costs incurred providing services that are shared by all customers, namely those relating to the security of supply and those associated with the decarbonisation of the sector. There is, in effect, only one possible “buyer” of these goods of security of supply and lower emissions, namely society as a whole. It appears that a trading scheme is not effective in delivering a public good, since it may lead to unsatisfied demand, as generators “sit on their hands”, as well as volatile prices. Therefore, some “obligation to supply” is required.

I believe that Adam Smith would have recognised this problem. Although he believed that the “invisible hand” would enable public good to flow from the activities of profit seeking industrialists, he also stated that Government has a duty to provide three services:

- Provision of security, i.e. maintain an army and the police,
- Justice; and
- Infrastructure, such as the provision of a bridge to allow a market town to flourish.

All three of these services are shared by citizens. It is not in any one citizen’s interest to pay for the service, since it would not make financial sense. Yet if they all club together, they all benefit. I am not suggesting that the Government should, therefore, provide all electricity supplies. Just that the Government has some role in ensuring that supplies are secure.

Do markets have a role at all?

The market’s difficulty in providing capacity at peak does not, in my mind, imply that competition has no role in electricity supply. It is just necessary to determine where competitive forces are likely to be most effective and where administrative procedures are likely to be better.

The reason for the hiatus in the construction of new generating capacity during the 2000s may be understood in terms of the risks facing a developer contemplating building an electricity production unit in a competitive market. They are:

Construction –	can the plant be built to time and cost?
Operation -	will the plant operate as expected?
Demand -	will the unit be required when constructed, i.e. at a time of high prices, rather than after prices have collapsed?
Technology/fuel -	will it be rendered uncompetitive by other technologies?

The experience of the British power market over the past thirty years has demonstrated that the industry ***is*** willing to absorb construction and operating risks, but not those associated with the timing of construction, or choice of technology or fuel. Looking forward, in order to meet the net zero targets, the industry will be seeking to build off-shore wind, carbon capture and storage and nuclear plant – all of which have long lead times and are capital intensive.

This implies that it would be appropriate for the private sector to compete to construct and operate plant but for the risks of the choice of technology and the timing of investment to be absorbed by all customers. In other words, competitive forces could be employed to drive improvements in construction and operating costs through auctions to allocate long term contracts for wind, solar and other non-fossil electricity – but it will be for Government to determine how much of which technologies to build and when they should be commissioned. This is the situation which currently exists in Britain, whereby all major new generating capacity has secured long term contracts. However, the mechanism by which these generators are remunerated is unlikely to be fit for purpose. In simple terms the Contract for Differences will not be able to secure stable prices for the generators, as the generation market becomes dominated by more intermittent forms of production with zero marginal costs.

Why the current support system will become unworkable

The contracts for differences (CFDs) issued for new generation depend on the generators being able to sell the power they generate through the contract market and achieve the national average price. If, for some reason, they fail to match this national average price, the top-up they receive may not be sufficient to attain the strike price they had secured in the auction process. As explained in the Appendix, this risk is currently low, since it should be relatively straightforward for generators to achieve the average market price. However, as existing stations retire and are replaced with non-fossil generators having zero or very low marginal costs, prices in the day ahead contract market will become far less predictable. It would not be surprising for a large off-shore wind farm, or a nuclear generator, to fail to achieve this national average price when selling its power. With such uncertainties, Generators will hold out for higher strike prices in the auction, or they may simply not participate.

The Solution

In recognition of the change in the underlying cost structure with generation becoming dominated by technologies with zero marginal cost, I suggest that Britain dispenses with the half hourly wholesale contract market. As an alternative, I suggest an Exchange is created to:

- Inherit the existing contracts and convert them into contracts to buy power at the previously negotiated strike price, with incentives for availability.

After discussion with Government and National Grid, the Exchange will:

- publish forecasts of electricity capacity and demand on the Distribution and Transmission systems for the next decade and indicate regions requiring additional capacity.
- invite tenders to build and operate new capacity and battery storage. The contracts would be allocated on the basis of availability, efficiency (for thermal plant) and contract price (£/MWh) and be for the operating life of the plant.
- Invite tenders for the remaining life of existing fossil capacity. The payments would be related to:

£/kW adjusted according to availability.

£/MWh – determined by market prices for fuel and target efficiencies for different technologies.

The Exchange will, after discussions with National Grid:

- Establish and publish a tariff at which power will be sold to Suppliers during each half hour – probably differentiated by weekday/weekend and season.
- Publish the means by which changes to these tariffs will be made, reflecting fuel prices, emissions costs and consumption levels.
- Establish tariffs for load management.
- Arrange for top-up and back up supplies for embedded generation.

Commercial consequences

Under the current arrangements, the Generators' profitability is driven by swings in underlying fossil prices and, when they occur, shortages of capacity. Under the Exchange regime, Generators' profits would be entirely dependent on the skill with which they build and operate their plant, rather than trade power and fuel. For those owning fossil stations, it would also depend on their ability to purchase fuel effectively. Generation would, therefore, become an asset management operation and the exposure to energy trading would diminish. This would make them low risk investments and improve their ability to secure finance at advantageous rates. This is particularly important as most of the new forms of generation being contemplated are highly capital intensive, making financing costs the major determinant of the wholesale price.

The Supply business would not need to "trade" power, given that there will only be one source of wholesale electricity, namely the Exchange. The profitability of Suppliers would be determined by their ability to operate effective billing systems, call centres and customer care schemes, such as the provision of energy efficiency measures, and thereby win market share.

No longer would there be the paradox of customers on supposedly "green" tariffs seeing their prices rise on account of a surge in gas prices. Indeed, the offering of such tariffs was very questionable in the first place, given the difficulty of differentiating electricity by source. This should increase customers' confidence in the transparency of electricity supply.

Given these potential improvements, it seems to me that the loss of allowing "the market" to decide when and what power stations to build will be more than compensated by the lower cost of finance for generation, the recovery of confidence in the reliability of supply and the improvement in customer care.

I am not advocating a return to monopolistic provision of electricity supply of the CEGB. The new entity would purchase all its power from privately owned companies through a series of competitive auctions when it deemed necessary. It is only the choice of the technologies and timing of construction that would be retained by this Exchange. The experience of the British electricity market demonstrates that allowing competition to occur every half hour has had a detrimental impact on the final price customers pay for power. Customers would be better served if the "competition" is restricted to the auctions for long term contracts.

Conclusions

This analysis has demonstrated that the goal of providing clean, secure and affordable electricity whilst transitioning to net zero will not be met by allowing "the market" to decide what type of new generation to build and when it should be commissioned. Relying on a competitive market to deliver low carbon technologies is likely to be unsustainable, given the nature of the new technologies and the way in which markets operate.

The preference for market mechanisms, whilst understandable, has obscured the fact that centrally coordinated purchases of power under long term contracts would provide a better service. This new entity could encourage competitive forces where they can have a real and beneficial effect.

Anthony White

28thSeptember 2023

Appendix

This Appendix describes how electricity is traded in Great Britain. The trading system has changed since first introduced in 1990. Initially all generators were obliged to be party to a pooling and settlement agreement. Such coercion ran counter to the liberal philosophy of the time and it was always intended that the trading arrangements would evolve. Nevertheless, it is worth considering how it operated in order to understand the challenges facing the current trading arrangements.

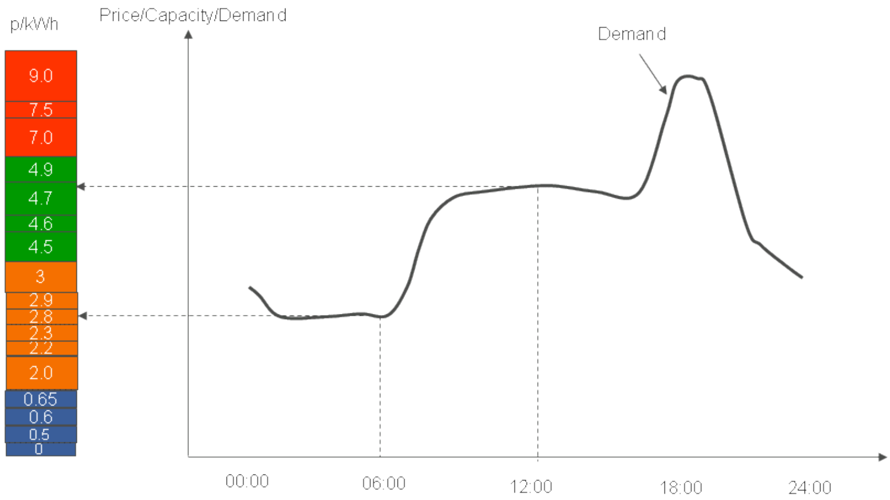
The original "Pool"

The "Pooling& Settlement Agreement" of 1990 provided central coordination of all power stations connected to the Transmission network and arranged that all power generated at a particular time (half hour) was priced at the same level. In this way, the inability to store electricity and differentiate between difference sources of power was accommodated. In simple terms, each day every generator unit would inform National Grid how much power it could generate on the following day and the price at which it was willing to operate. National Grid then listed all generating units in order of these declared prices. It then estimated demand in each half hour and selected only those generating units required to meet this demand. The "System Marginal Price" was set for each half hour as the bid price of the last (most expensive) generator required to meet that half hour's demand. The actual price for each half hour was then found by adding an amount that was intended to encourage generators to offer capacity, based on an assessment of the likelihood that demand would not be met, owing to generator malfunction and the "value" customers may ascribe to avoiding this "Loss of Load". This was added to the "System Marginal Price" to become the "Pool Purchase Price".

National Grid would then carry out further calculations using these same offer prices but also taking into account the physical capability of the transmission system. This added further costs which were spread equally across all customers and resulted in the "Pool Selling Price". For most of the time, System Marginal Price was the largest component of the Pool Selling Price.

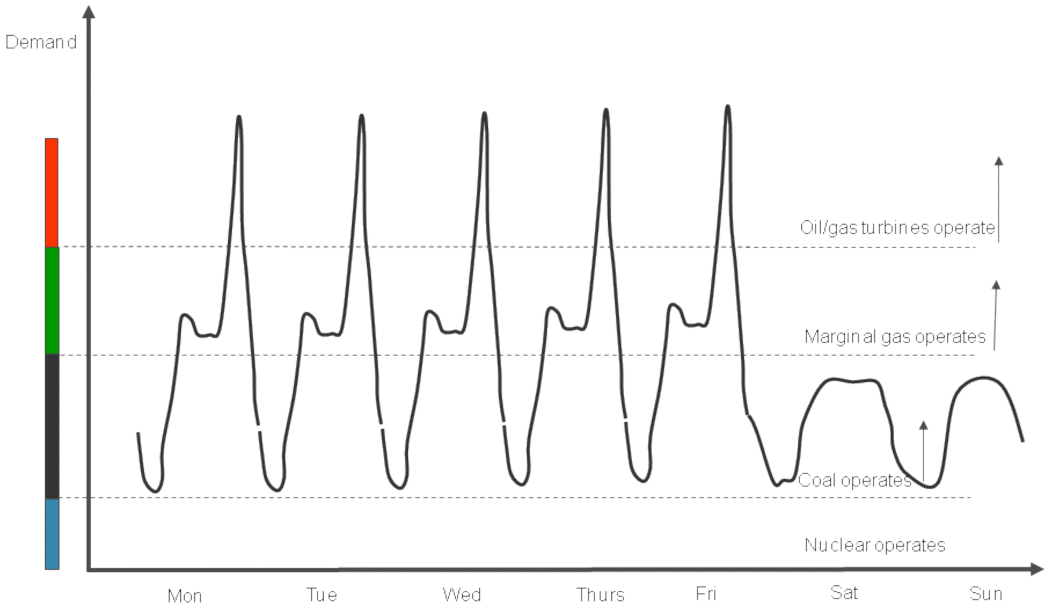
This pricing mechanism incentivised generators to offer their units, or "bid", at prices related to the marginal cost of their fuel. The result is shown diagrammatically in Figure A1 below. The "stack of power stations on the left would have led to a price of 2.80p/kWh (or £28/MWh)at 6.00am and 4.70p/kWh (£47/MWh) at noon.

Figure A1 - Merit order pricing



This was quite an operation but it did the trick. The power stations' operations were co-ordinated and demand was met by the cheapest power stations available. Depending on the level of demand, different power stations operated, so the more expensive were only "despatched" when demand rose, as shown in figure A2.

Figure A2 – Merit order dispatch



As expected, this led to the half hourly "pool" price varying with demand. Most customers' meters are not read half hourly. As a consequence, the Generators and Suppliers entered into contracts to stabilise the prices at which they traded power. These operated "outside" the pool and determined payments based on the pool price.

In the event, over 90% of power traded in England & Wales is priced according to the contracts agreed between Generators and Suppliers. The pooling arrangements determined the price at which participants in the wholesale market balanced the difference between their contract and physical positions. As such, this price was set by National Grid's forecast balance of supply and demand for each of the half hours made the previous day and the underlying costs of generation, such as oil, coal and gas prices. It followed that the pool prices, and contract prices, were closely related to fuel prices when the market was competitive.

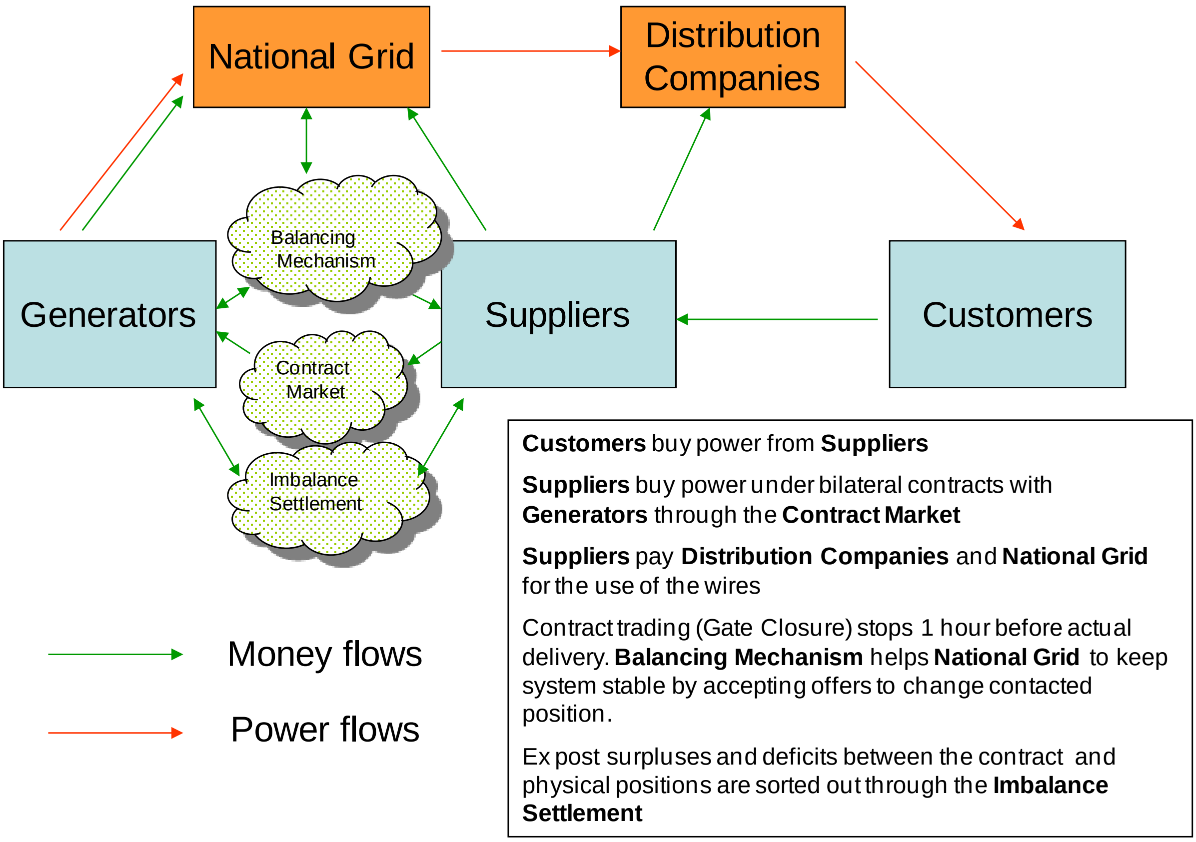
The contracts could be “one-way”, whereby a Generator would recompense the Supplier if the pool price was greater than the agreed “strike” price. Or they could be two-way, whereby the Supplier would compensate the Generator of the pool price were lower. The duration of these contracts tends to be for one year or shorter and may only relate to weekdays or weekends, day time or off-peak. The most frequently traded contracts were “day ahead”, i.e. an agreement on price for the following 24 hours.

NETA & BETTA

Under the New Electricity Trading Arrangements (NETA) introduced in 1998, and subsequently British Electricity Trading and Transmission Arrangements (BETTA) in 2000, Generators inform the “System Operator” (SO), how much generation they are going to produce an hour ahead (“gate closure”), **and the amount of capacity** they have sold for the next half hour. Similarly, Suppliers submit the likely **demand of their customers** and how much of this consumption is covered by contracts. Thus the market’s participants, rather than National Grid, determine the demand forecast adopted. Both also tell the SO the price they would charge if later asked to alter their behaviour because, for example, demand turned out to be higher or lower, or if a generating unit suffered an unexpected failure.

The SO then ensures that the power stations meet demand using a “balancing mechanism” in which it calls on the offers to change behaviour in the light of actual circumstances. The SO charges those whose physical positions differed from their submissions through the “imbalance settlement”. This is shown diagrammatically in Figure A3

Figure A3 Trading Arrangements under BETTA



The consequence of these new trading arrangements is that the imbalance prices, unlike the "pool price", bears no relationship to the underlying balance of demand and supply, nor to underlying fuel prices. They solely relate to the balance of supply and demand between the differences between participants contractual and physical positions in every half hour.

Contract Position

Suppliers and Generators tend to be fully contacted at "gate closure" and most trading between parties is conducted through Day Ahead trading, as well as contracts of longer duration, around one or two years. When the Pool was in existence, i.e. until 1998, Suppliers and Generators could have some confidence that, if their contract position differed from their actual generation or consumption, the difference could be made up at pool prices which bore some relation to the underlying fuel prices. That confidence was weakened after the introduction of NETA, though, in time, it was re-established as gas stations tended to be at the margin and so set prices.

Implications for New Capacity

The CFDs by which the LCCC secures new capacity are struck with relation to the strike price and a "reference" price, which is meant to reflect the national average price mentioned in the main text. For offshore wind prices, for example, this reference is the average day ahead price. A problem may arise were a generator's revenues from the contracts it holds with Suppliers to differ from this reference price. If the generator had, somehow, been able to secure a higher average revenue, it would enjoy superior returns. On the other hand, if its revenues were lower, then it would face lower returns and may even be loss making. This uncertainty is known as "basis risk".

At present, investors regard this basis risk as low, since day ahead prices are driven by marginal costs which, currently, are determined by gas generators – and Generators are able to stabilise their positions, should they so choose, by trading in the underlying gas market. However, as gas generation dwindles as the contribution from non-fossil generation increases, there will be periods when all the plant operating, i.e. wind and nuclear, will have zero marginal cost and so prices will be far more volatile. It will be more difficult for a Generator to be confident that its revenues from its contracts with Suppliers will match the reference price. This "basis risk" will grow. Developers wishing to secure long-term finance in order to construct a new lant will have difficulty convincing financiers that this basis risk is manageable at a reasonable cost. It seems to me, that the current trading system cannot last in its current form for many more years.

AALW

28th September 2023

Anthony White started his career working for the CEGB in 1977 where he led the geothermal energy team at Marchwood Engineering Laboratories. He then spent two years as a Harkness Fellow at the Los Alamos Laboratory, New Mexico, the Electricity Power Research Institute in Palo Alto and Brown University. He returned to the CEGB and worked in the Health & Safety, Corporate Strategy and Finance Departments and he left in 1989 to join James Capel, the Government's broking Advisor for the Restructuring and Privatisation of the Electricity Supply Industry in England & Wales. He joined the National Grid Company in 1992 and introduced what became the Transmission Services Scheme and was appointed to the Executive Committee. He has worked for Kleinwort Benson and Citigroup as head of the European Utilities Teams and was a Managing Director of Climate Change Capital. He served as a Non-Executive Director for Green Energy Options, The Crown Estate, Solar Century, the National Renewable Energy Centre, The Low Carbon Contracts Company and Triple Point Energy Transition Limited. He has been appointed to a number of Government Advisory Boards and Commissions.