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Restructuring the Chinese Electricity Supply Sector - *How industrial electricity prices are determined in a liberalized power market: lessons from Great Britain*

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Keywords Chinese power market reform; industrial electricity price; electricity liberalization

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Restructuring the Chinese Electricity Supply Sector
- How industrial electricity prices are determined in a liberalized power market: lessons from Great Britain

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1. Introduction

This paper aims to unpack how the price of industrial electricity is determined within the liberalized power market in Great Britain in the context of the ongoing reform of the Chinese power sector, initiated by the March 2015 No.9 document.

It is organized around a discussion of the various components of the final industrial price of electricity (namely the wholesale price, the retail margin, network charges, the costs of system operation and government taxes and levies). In the case of each component, we consider what drives its total cost and its pricing structure.

The paper has arisen from an ongoing research project involving the authors and multiple stakeholders across China. The associated dialogue has resulted in two papers looking at the general international lessons from power sector reform for China (Pollitt et al., 2017) and the specific lessons arising from the pilot power market in Guangdong province (Pollitt et al., 2018). Those earlier papers set the scene for this one, in that they contain lots of detail on the state of the reform, its underlying objectives and the general applicability of international reform experience to the unique context of China.

By way of background, we briefly summarise these two earlier papers.

The first paper examined how the then high price of industrial electricity in China (in 2014) could be reduced by the apparent unexplained gap between the China and the United States in industrial electricity prices. This gap required a 12% price fall in the Chinese price to be eliminated. We suggested four lessons from international experience[2] which could deliver this: reform of power plant dispatch (which would allow industrial prices to fall by 1-2%); increasing the efficiency of the grid companies (which might reduce industrial prices by 2-3%); rebalancing charges away from industrial to residential customers to better reflect underlying system costs (which might reduce industrial prices by up to 5%); and reducing the high rate of investment in generation/networks (could reduce prices for industrial customers by of the order of 3%).

The second paper examined the development of the electricity market pilot in Guangdong province. Guangdong is a leading reform province, but it has very high industrial electricity prices (150% higher than a reasonably comparable industrial US state such as Texas). Following the March 2015 reform document we can observe impressive entry of new retailers into the power market and reforms appear to have reduced power market prices by around 10%. However, we observed a number areas for improvement in the operation of the wholesale power market and the regulation of network charges. On the power market itself these included: a lack of price transparency to the players; that market prices were not integrated into dispatch decisions; the need for more comprehensive markets covering more volume and more electricity products; current excess supply, that may encourage over-competitive bidding; and problems with market clearing rules. More generally we

[2] Our international lessons drew on Joskow (2008) and Pollitt and Anaya (2016).

noted the need for: an independent regulator and clear responsibility for enforcement of the Anti-monopoly Act; possible asset reallocation given largest firm has 30% of generation; the importance of transmission and distribution charge reform, in overall price reduction; and clarity on the future of the reforms, which currently lack legislative backing.

In this paper, we begin by discussing the components of the price of industrial electricity in Great Britain, as an example of a fully reformed electricity market, where the market is roughly comparable in size to a reasonably large Chinese province. We proceed to discuss the key actors in the liberalized electricity system in Great Britain, before unpacking each of the components of the price. We discuss the market determined elements first, then go on to introduce and discuss the regulated elements of the price before finishing with the central government determined price components. Our discussion covers the determination of the wholesale price, the retail margin, transmission charges, system balancing charges, distribution charges and environmental levies and taxes. In each of these cases we discuss the process by which they are determined (led by the market, the regulator, the central government or more than one) and the specific lessons for China. We conclude by emphasizing some of the high-level lessons on electricity price determination for China.

2. How is the industrial electricity price set in Great Britain[3]

The final retail price of industrial electricity is made up of six elements in Great Britain. These are a combination of unregulated market determined elements (the wholesale price and the retail margin); regulated charges (transmission and distribution charges); central government determined levies and taxes; and mixed elements (system balancing charges) that are made up of both regulated and market determined costs. The final price (charged by retailers) is not regulated for typical industrial customers. Regulated charges are determined by an independent regulatory agency. Central government levies and taxes are the responsibility of the Finance Ministry (HM Treasury in the UK). In the UK we distinguish between industrial, commercial and residential users, so the category of industrial users is narrower than in China, where ‘industrial’ covers both industrial and commercial customers.

The breakdown of the final price of industrial electricity in the UK in 2016 is shown in Table 1, for industry consuming more than 2000 MWh per year. This shows that roughly 40% of the cost is market determined, 20% is determined by the regulator and 40% is determined by the central government. We will discuss each of the sub-elements in the paper. Note the price of industrial electricity in the UK in 2016 is roughly equal to the price of industrial electricity in Guangdong in 2015 (see Pollitt et al., 2018).

[3] For electrical purposes, the United Kingdom is divided up into two administrative areas: Great Britain and Northern Ireland. Electricity in Great Britain is regulated by Ofgem. Some of the statistics we refer to below include Northern Ireland in the UK, but Great Britain is responsible for around 98% of electricity consumption in the UK.

Table 1
Breakdown of industrial price in UK

2016		Euro/MWh	%
Market determined prices			**40.1%**
Generation costs		39	33.9%
Retailer (Supplier) costs		7.15	6.2%
Regulated charges			**19.7%**
Transmission charges		11	9.6%
System balancing charges		2.6	2.3%
Distribution charges		9	7.8%
Levies and Taxes			**40.2%**
Renewables Obligation		17.5	15.2%
FITs		5.24	4.6%
Hydro benefit scheme		0.2	0.2%
Climate change levy		2.66	2.3%
Carbon reduction commitment		4.4	3.8%
Carbon pricing		16.25	14.1%
		115	100%

Source: Derived from Grubb and Drummond (2018). Before discounts. Band 1D to 1F customers, 2000MWh+ annual demand. £1=1.16 Euros

At the outset, it is important to clarify the role of government in the UK electricity sector: the government does not determine the final price[4]; the regulator does determine the maximum revenue for regulated elements; the regulator does approve the tariff methodology for regulated charges; the regulator does determine security of supply requirements and penalties; the government does monitor competition in power markets. While electricity market reform may have the aim of delivering low prices, lower prices are not always the right answer. When fossil fuels are becoming more expensive or generating capacity is getting scarce, higher prices may be the right answer.

3. The key actors in the electricity system in Great Britain

The UK electricity sector in 2017 can be characterized as follows.[5] It had final consumption of 301 TWh, this has been falling since its peak in 2005 (it was 14% lower in 2017 than the 2005 peak). This reflects changing industrial structure and a large rise in energy efficiency (household energy demand is 16% below its peak, in spite of a rise in the number of households). Energy supply in 2017 was 353 TWh, of which 4.2% was imports. Of domestic generation of 336 TWh, 40.4% was from natural gas, 29.3% was renewables and 20.6% was

[4] In the residential sector, there is retail price cap (known as 'safeguard tariff'). However, this is a maximum tariff. Actual tariffs can be lower than this.
[5] See Digest of United Kingdom Energy Statistics 2018, (BEIS, 2018).

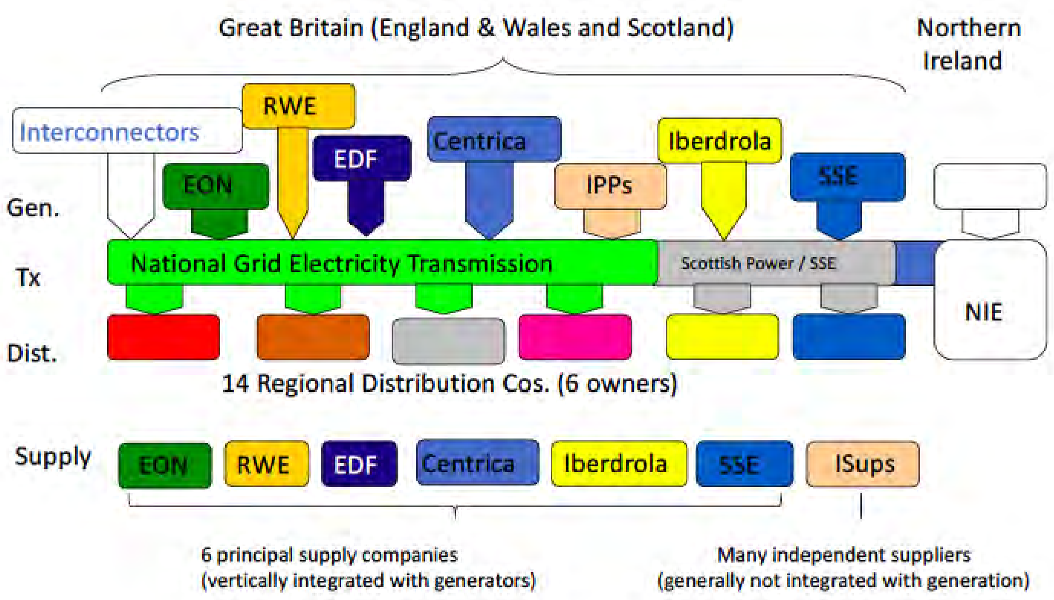
from nuclear, with only 6.7% from coal. The speed and extent of the transition away from coal and towards renewables in the UK electricity system has been remarkable and demonstrates – in line with more general evidence[6] - that electricity reform is not incompatible with ambitious environmental targets. In 2010 renewables made up 6.9% of electricity generation, while coal was 28%[7], 7 years later this has been more than completely reversed. In 1990, at the time of the introduction of the electricity market, the UK was generating 72% of its electricity from coal.[8]

The reform of the electricity sector in the UK from 1990, significantly changed the institutions involved in the electricity sector.[9] In England and Wales the monopoly pubic generation and transmission company (the CEGB) was broken up and 12 regional electricity distribution and retail companies were able to enter generation and compete with one another for retail customers (via legally separate retail businesses). In Scotland and Northern Ireland incumbent integrated generation, network and retail companies were also subject to breakup and competition.

In mid-2018 there were 170 licensed generators and 64 licensed non-domestic electricity retailers in Great Britain.[10] Figure 1 shows the current structure of the industry. In Great Britain generation and retail is dominated by 'big' six generator-retailers, which have arisen from incumbent companies. Transmission in England and Wales is owned by National Grid and distribution is owned by 6 companies (including UKPN and WPD). National Grid is the system operator for the whole of Great Britain. While some companies continue to have interests in generation, distribution and retail, this is now much less common and there is strict legal unbundling of distribution network businesses from the competitive parts of the electricity sector. Independent power projects and new retailers have taken significant market shares from the 'big' six companies, and the generator and retailer market shares are not matched within the 'big' six.

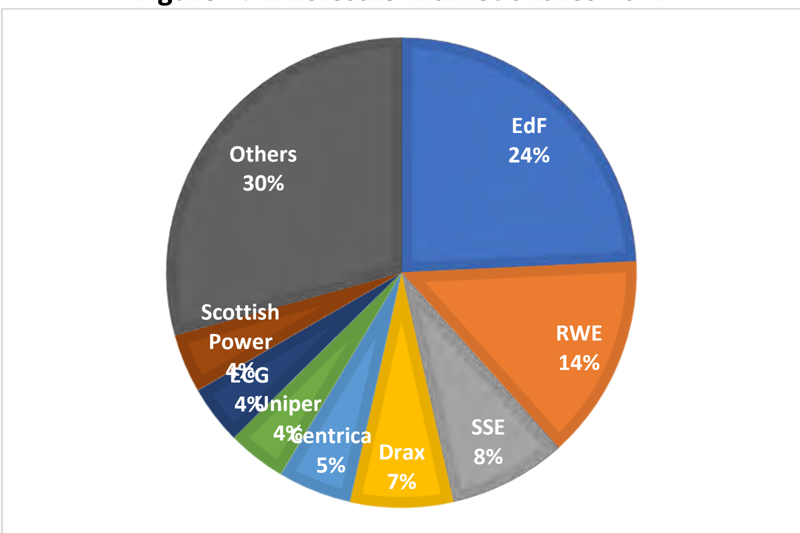
[6] See for example, Vona and Nicolli (2014).
[7] See DECC (2011).
[8] See DECC (2009).
[9] See Henney (1994) for the definitive discussion of what happened (and why) at the time of privatisation to the structure of the electricity industry. For an excellent summary of the GB experience following privatisation see Newbery (2000) and (2005). For a discussion of the electricity privatisation in the context of the general privatisation programme in the UK, see Pollitt (1999), and for a discussion of electricity liberalisation in the global context of energy market liberalisation, see Pollitt (2012a).
[10] Source: Ofgem (2018a), https://www.ofgem.gov.uk/system/files/docs/2018/10/state_of_the_energy_market_report_2018_1.pdf

Figure 1: The Structure of the Electricity Industry in the UK



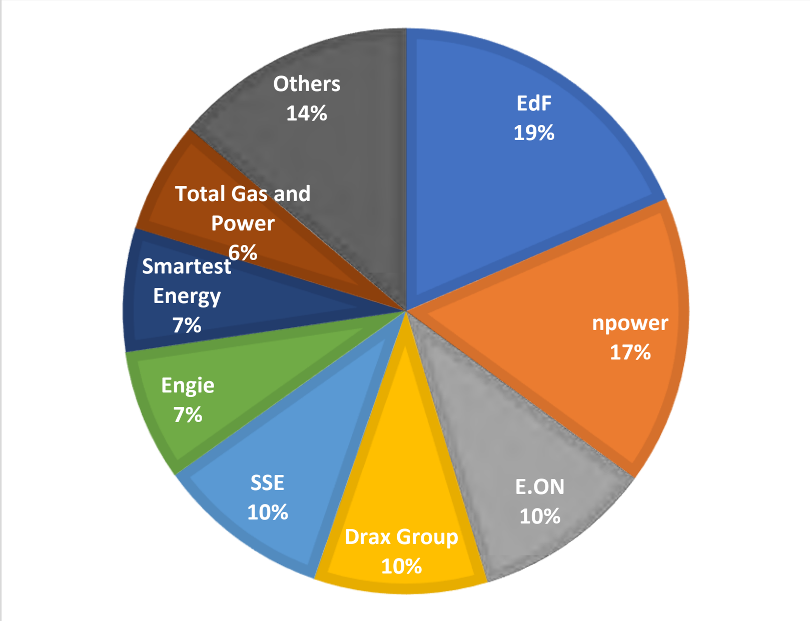
Figures 2 and 3 show the market shares in both the wholesale electricity market and business retail market in 2017. The HHI index for the wholesale electricity market is around 1034, indicating that market concentration is relatively low, equivalent to 10 equally sized firms competing with each other. For the retail market the HHI is even lower, at around 1000.

Figure 2: Wholesale Market Shares 2017



Source: Ofgem (2018), State of the Energy Market Report 2018, p.50.

Figure 3: Business retail market shares 2017



Source: Large-scale electricity profile class 5 to 8 +HH:
Ofgem (2018), State of the Energy Market Report 2018, p.38.

There are 7 electricity distribution network companies in the UK (UKPN, WPD, Northern Powergrid, Electricity Northwest, SP Energy Networks, Scottish and Southern Energy (SSE) Power Distribution and Northern Ireland Electricity (NIE), covering 15 monopoly distribution areas. Of these groups only two are now part of companies with either generation or retail interests in the UK (SP Energy Networks and SSE Power Distribution). There are four onshore transmission companies in the UK (National Grid, SP Energy Networks, SSE Power Distribution and NIE).

The ownership structure of the electricity industry in Great Britain in very diverse. Two of the 'big' six generator retailers – SSE and Centrica – are listed on the London Stock Exchange, together with the generator Drax and the transmission company National Grid. The other four major generator retailers are subsidiaries of large pan-European energy companies - EdF, RWE, E.ON, Iberdrola. Of the distribution companies UKPN is owned by Hong Kong investors, while WPD is owned by PPL, a listed energy company in the US, Northern Powergrid is owned by Berkshire Hathaway and Electricity Northwest is privately held. The ownership of the UK electricity industry reflects significant foreign ownership. The attraction of holding UK electricity assets reflects diversification by shareholders in other countries. This makes UK domestic regulation easier (because it weakens the lobbying power of producer interests and enables the regulator to focus on UK consumers). It also facilitates reciprocal UK investment abroad (not just in the electricity sector).

Other key actors in the electricity sector in Great Britain are worth mentioning.

Elexon administers the balancing and settlement system for reconciling payments between generators and retailers within the electricity industry. This is an extremely important part of any restructured industry. Elexon describes itself in the following way: 'In March 2001, the Balancing and Settlement Code (BSC), was launched as part of NETA (New Electricity Trading arrangements). ELEXON administers the Code on behalf of the UK electricity industry. We provide and procure the services needed to implement the code and compare how much electricity generators and suppliers say they will produce or consume with actual volumes. We work out a price for the difference and then transfer funds.'[11] Elexon was established by an obligation in National Grid's transmission licence and, technically, is wholly owned by National Grid but operates at arms length to it with a completely separate governance structure.

The power market is also characterised by a number of other players. These include *aggregators* (who aggregate up both generation and demand on behalf of smaller generators and smaller non-domestic customers). There are around 19 of these.[12] *Traders* who trade electricity financially on the available power exchanges. Power can be traded across multiple platforms a day ahead (or under longer term contracts). These *trading platforms* include APX Power UK and N2EX. There are around 75 traders on APX.[13] Interconnectors are also significant in the Great Britain market. These offer the ability to both supply power into and out of GB (acting as generators and loads). Currently these interconnectors are: 2GW to France (IFA); 1GW to the Netherlands (BritNed); 500MW to Northern Ireland (Moyle) and 500MW to the Republic of Ireland (East West). There is another 3.4 GW under construction (as of October 2018).

Finally, it is important to note the role of the regulators and the government within the electricity system. While there is no state ownership of operational electricity assets[14] in the UK, the government does influence the industry via the regulatory regime and central government ministries. The GB industry is directly overseen by two independent regulators: Ofgem (the Office of Gas and Electricity Markets) and the CMA (Competition and Markets Authority) which is the general competition authority. The primary duty of these two regulators is to oversee the competitiveness of the electricity sector in both the wholesale and retail markets and to approve and monitor monopoly network charges. These two agencies operate at arms-length from government. However, the central government, led by the Department for Business, Energy and Industrial Strategy (BEIS) sets regulatory framework, can issue guidance to the regulator, sets subsidy and tax regime and can refer the whole industry for investigation to the CMA[15]. Members of the regulatory boards are appointed by Government for a fixed term.

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[11] https://www.elexon.co.uk/about/

[12] See PA Consulting Group (2016), https://www.ofgem.gov.uk/system/files/docs/2016/07/aggregators_barriers_and_external_impacts_a_report_by_pa_consulting_0.pdf

[13] See http://www.epexspot.com/en/membership/list_of_members

[14] The government does own decommissioning nuclear power plants, and some test reactors. Municipalities have limited interests in local electricity companies, e.g. Bristol Energy.

[15] See CMA (2017), https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/624706/cma3-markets-supplemental-guidance-updated-june-2017.pdf

4. Wholesale prices

We now turn to the elements of the final price of industrial electricity and how these are determined. An obvious place to start in thinking about the wholesale electricity price element of the final price is the spot market price for electricity. So, what do we mean by a spot market in a liberalized power market?

We normally mean the main near real time market (see Stoft, 2002) in which the wholesale prices determined every hour, half-hour, 15 minutes or 5 minutes from supply offers and demand bids from individual generators and retailers wishing to sell and buy power. Underlying bids and offers guide dispatch of individual power plants. In many power markets generators can declare prices (e.g. in PJM market in the USA) at which they are willing to be dispatched or quantities (e.g. in the market in GB) which they want to be dispatched to system operator. 'Spot' prices/quantities should reflect the underlying value of generation and loads. The system operator uses such spot prices/quantities to dispatch the system paying attention to the need for instantaneous correction to match supply and demand in real time, on the basis of constraints and balancing markets/contracts. There is always an issue of how to link spot market prices (which are often day-ahead) and physical dispatch. Instantaneous bidding is neither possible nor desirable because instantaneous prices cannot change behavior in real time and might lack transparency (as in practice they have to be calculated ex ante).

Within a power market actual real time grid stability is physically maintained in much the same way as in traditional vertically integrated power systems, following 'gate closure' (the last chance for generators and loads to change their market position). However spot markets do create opportunities for withholding by generators as in the California electricity crisis of 2000-01[16], whereby generators manipulated market prices by withdrawing some capacity deliberately to drive up prices on their remaining generation. This sort of behavior must be monitored, detected and penalised.

A crucial part of the wholesale market is the presence of retailers who buy power on behalf of their customers. In Great Britain retailers need to buy wholesale power to cover 100% of their power sales. Retailers are often integrated with generators. Retailers can use spot and forward markets and bilateral contracts. Derivative energy products are available[17]. A lot of power is bought and sold on bilateral contracts for 12-18 months, often linked to spot prices. Retailers often hedge using rolling contracts (e.g. by rolling over 18 month contracts every month, thus taking 18 months for any sustained adjustment in the underlying prices to be fully reflected in their wholesale generation contracts). Smaller retailers tend to use shorter term contracts. This is because there is more relative uncertainty for them on their future demand and they compete on basis of short term price competitiveness rather than reputation. Some jurisdictions (e.g. in South America) specify the nature of contracts that should be entered into for regulated retail customers. This can be done indirectly by

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[16] See Sweeney (2002).

[17] See London Energy Brokers Association: www.leba.org.uk

specifying the benchmark wholesale contract price that will be used in the calculation of the maximum regulated retail price.

In GB the bilateral contract markets and the power exchange (PX) are not run by the system operator (SO). Instead the SO operates the half hourly balancing market and other ancillary services markets (e.g. for frequency response). 97% of all wholesale energy is self-dispatched in GB. This is different from a compulsory pool/mandatory day ahead (DA) market such as used in the US (e.g. by PJM) where the system operator uses the day ahead market to guide pricing and dispatch in real time.[18]

How self-dispatch works is as follows. Generators can give their Final Physical Notification (FPN) to the system operator of which plants they want to run happens up to 1 hour ahead of real time, i.e. generators can adjust their stated position up to that time. After that, the system operator takes control of the plants with object of minimizing the costs of any balancing actions (i.e. the system operator is the sole counterparty to balancing market transactions). Production (generator) and consumption (retailer) accounts transactions (Energy Contract Volume Notifications, ECVN) must also be declared with consumption accounts noting position in all 14 distribution areas (as separate BMUs). Generators and retailers have a strong incentive to self-balance their individual positions either physically or via their participation in the balancing mechanism. Failure to self-balance implies exposure to balancing charges arising from the system operator's need to buy or sell power to exactly balance the system. Balancing charges are thus calculated to incentivize balance and encourage accurate supply and demand matching. There is an incentive to bid accurately as under competition law there is an up to 10% of turnover fine possible for market power abuse.

Such self-dispatch is different from PJM or China, but with sophisticated players this allows generators to reflect all of their internal costs in their notifications to the system operator. Self-dispatch offers the potential for improved market position/performance with plant risk issues in ways not facilitated by central dispatch algorithms, which although they can take formal account of many plant characteristics (such as ramping costs) cannot take into account *all* of the costs faced by an individual unit in being dispatched. It is important to note that the efficiency of self- vs central dispatch is usually measured with respect to a central dispatch calculation, thus is biased towards finding central dispatch more efficient and not modelling hidden constraints in system[19].

Power plants in Great Britain are dispatched in real time by National Grid, there are no other dispatch layers. The regional distribution companies do not dispatch generation or loads, though they may occasionally exercise constraint management contracts within the distribution system. Larger generators (on the distribution system) must be visible to the transmission system operator above 50 MW (as a balancing mechanism unit – BMU) and

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[18] See for example: http://www.gridscientific.com/images/electricity_trading_arrangements_beginners_guide.pdf And https://www.elexon.co.uk/wp-content/uploads/2017/11/BSCP01_v17.0.pdf and Onaiwu (2009).

[19] See for example Sioshansi et al. (2008).

can register below this size threshold.[20] Interconnectors to France, Ireland and Netherlands act like generators and loads. However, there is some inter-TSO collaboration through CORESO. It looks at how physical transmission can be configured to help maximise reliability and minimise congestion. It gives advice to the coordinating TSOs on how controllable devices like phase-shifting transformers, unconstrained DC links and discretionary switching can be used to help neighbours and hence overall network performance. CORESO is one of a number of Regional Security Coordinators (RSCs) of the EU single electricity market. It brings together 7 national system operators in western Europe which does coordinate 'from a few days ahead until Intraday (few hours before real time)'.[21]

The wholesale power market is closely linked to fossil fuel markets and carbon markets, via the fact that fossil fuel prices and carbon prices are an important cost component for any oil, gas or coal fired generation unit. Carbon pricing (both emissions permits and taxes) appears in wholesale generator costs as an extra fuel cost as fossil fuel generators have to 'burn' carbon permits and pay carbon taxes when they generate and produce carbon dioxide. The figures for wholesale costs in Table 1 net off the impact of carbon pricing, but reported wholesale prices include these costs. We discuss their determination in a separate section below. In Great Britain, most subsidised low carbon generation participates in the energy market like any other generator in real-time and receives top up revenue from contract for difference (CFD) and renewable obligation certificate (ROC) payments. Small FIT generators (mostly households) receive payment from retailer that they are contracted to sell to (the so called 'FIT Licensee').[22]

While wholesale power markets are not very concentrated in the UK now, that has not always been the case and there have been many examples of market power problems in electricity wholesale markets[23]. Indeed, tacit collusion is a very real problem in electricity markets at the wholesale and retail market levels due to repeated interaction of companies making bids and offers many times a day within transparent power markets. The regulator, Ofgem, has done a lot on transparency of profitability.[24] The GB market falls under REMIT legislation on energy market integrity and transparency.[25] Ofgem has referred the whole

[20] See National Grid (2011), https://www.nationalgrid.com/sites/default/files/documents/Managing%20Intermittent%20and%20Inflexible%20Generation%20in%20the%20Balancing%20Mechanism%20Consultation.pdf

[21] See https://www.coreso.eu/

[22] See https://www.ofgem.gov.uk/environmental-programmes/fit/about-fit-scheme

[23] See the discussion in Newbery (2005) and Jamasb and Pollitt (2005).

[24] See https://www.ofgem.gov.uk/gas/retail-market/retail-market-monitoring/understanding-profits-large-energy-suppliers. Ofgem requires the production of consolidated segmental accounts which show the profits of the large integrated firms in each segment of the GB market.

[25] See https://www.ofgem.gov.uk/gas/wholesale-market/european-market/remit

market to the CMA recently who examined competition thoroughly over the period 2014-16.[26]

Alex Henney (2011) documents the 8-year process that followed the introduction of the competitive wholesale power market in Great Britain, that eventually led to the much more competitive market that see today. This consisted of a series of investigations and reports with recommendations. These included the *Pool Price Enquiry December 1991* (by Offer – the then electricity only regulator which predated Ofgem) which found gaming by the two incumbent fossil-fuel generating companies declaring plant unavailable day ahead to drive up capacity price on the day and the *Report on Constrained-On Plant Oct 1992* (by Offer) which found gaming by behind constraint plants. Subsequent investigations led to significant structural changes: the *Pool price statement July 1993* (Offer) allowed the largest customers to bid in the Pool (to reduce generator market power) and then following the threat to refer the two largest generators to the competition authority in Feb 1994 (Offer), the largest generators agreed to sell power plants. However, the two major generators gamed this agreement by putting anti-competitive earn-out clauses into their power plant sales terms (raising the marginal costs faced by the new owners and forcing them to bid higher). Merger investigations (MMC 1996 a,b) in 1996 by the competition authority of the largest generators' proposals to buy retailers resulted in the mergers being blocked: this led to further generation divestitures before the mergers allowed. These asset sell–offs eventually led to wholesale power prices collapsing in early 2001[27]. Meanwhile the 1997-1999 investigation of pool arrangements[28], led to the New Electricity Trading Arrangements (NETA) from 2001, which replaced the Pool with self-dispatch and a balancing market.

The GB experience illustrates the importance of creating sufficient competition prior to the opening of the market. The creation of five equally sized fossil fuel generators (rather than two) in Great Britain in 1990 with a range of different power plants would have saved years of regulatory intervention to establish a competitive wholesale market. China has ample opportunity to learn from the UK and reorganize the ownership of its largely state owned electricity generation sector prior to full market opening. This would significantly improve its subsequent prospects for competition.

As in all markets for heavily standardized products, there is a need to monitor withholding and signaling of prices. The promotion of competition via new entry and interconnection is important, as monitoring and price regulation is less satisfactory than actual competition. Regulation of some bidding behind local constraints is likely to be necessary (in the UK withholding of generation capacity in Scotland has been an issue, behind a significant transmission constraint between Scotland and England). Rapid enforcement action against anti-competitive behaviour is helpful, in order to limit the damage done by it and to increase the deterrent effect of enforcement. The stimulation of competition may mean

[26] See https://assets.publishing.service.gov.uk/media/576bca94ed915d622c000077/appendix-4-1-market-power-in-generation-fr.pdf

[27] See Evans and Green (2003) for analysis of what caused the fall in wholesale prices around this time.

[28] See for example, Offer (1998).

that divestiture of generation plant by price-setting incumbents may be necessary. The independence of the SO from generation and retail is necessary in order to prevent (or highlight) anti-competitive actions by the SO aimed at promoting its own generation.

The reform of the electricity generation sector in Great Britain did raise the sort of 'social stability' issues that are important in China. Collusion to raise the price of generation from existing generators and divestitures by the incumbent generators probably accelerated the run-down of coal fired generation in favour of gas (see Newbery and Pollitt, 1997, and Newbery 2005). The government attempted to slow the reduction in the use of high priced domestic coal by privatized generators by signing preferential contracts for domestic coal for the first few years after the creation of the market. Subsequently, it announced a 'gas moratorium' in 1997 – which made it more difficult to get planning permission for new gas fired power plants - in an attempt to slow build of gas fired generation, to promote coal use in electricity generation.[29] Renewables support (especially for onshore wind in Scotland and offshore has been promoted partly as a way of supporting Scottish development and northern ports (e.g. Hull). The withdrawal of financial support for onshore wind in England (from 2017) was also about local residents' opposition to the siting of wind parks. Carbon pricing was initially kept low in 2013-14[30] so as not to accelerate run down of coal, but has since then has strongly favoured gas fired generation (as we discuss below).

Following the reforms in 1990, nuclear generation was unable to cover its long run costs in the new electricity market (though its participation in the wholesale market strongly incentivized it to lower its operating costs and increase its output, which it did very effectively), but the whole retail base was subject to a levy which built up a fund to finance long term nuclear liabilities. Falls in the electricity price in 2001-02 caused the financial collapse of the nuclear generator British Energy, which was successfully rescued by the government and returned to the private sector (at a profit to the government).[31]

Several additional aspects of the GB wholesale power market are important for China as it proceeds with wholesale power markets. All generation is in the market (including all renewables and nuclear), not some of the generation as with many of the current round of pilot markets[32]. Demand participates directly in the market and bidding is two sided in the sense that generators and loads participate in wholesale markets. There are a range of contracts between retail and generation, not just one type of financial product (e.g. monthly contracts as in Guangdong at the moment, or day-ahead contracts in California pre-crisis). There are strong incentives on generators to make least cost plant available. Plants are dispatched by the system operator on basis of declared availability and least cost adjustments. There is complete transparency on government attempts to influence dispatch and investment (e.g. via coal contracts or bans on certain types of generation). In wholesale

[29] The moratorium was short-lived and not particularly effective. It was abandoned in mid-1999 and was never a complete ban.

[30] See Hirst (2018) for a discussion of the history of carbon price floor in the UK.

[31] See Taylor (2007) and (2016).

[32] See for example discussion of this in the context of the Guangdong market pilot in Pollitt et al. (2018).

power markets active competition and regulatory policy has been very important in promoting competition.

While spot markets are relatively easy to set up, futures markets for electricity take time and have been considered problematic.[33] This is because liquidity is an issue in a market with important underlying physics which limits the ease of modelling future prices. Physical delivery has to occur in real time and stocks do not exist in electricity markets. This means that electricity markets are difficult to model years ahead and incumbent generators and retailers are strongly favoured as participants in electricity futures markets. Financial electricity futures markets do not necessarily bring major benefits to electricity consumers as they primarily exist to serve the needs of financial investors. Financial instruments should of themselves be of limited interest to electricity regulators and should primarily be the concern of financial regulators.

The GB market is equivalent to provincial market in China. It is important to say that GB sits within an increasingly integrated single electricity market across Europe. Spot markets across Europe are subject to market coupling (via the EUPHEMIA algorithm)[34], whereby prices are the same in different spot markets in the absence of transmission constraints. This is a point of coordination where power exchanges need to use information on available transmission capacity (or available transfer capabilities – ATCs) from TSOs to resolve prices within zones. Extending markets over wider areas has benefits in terms of increased market efficiency[35] and where there is political support for price convergence (particularly in the low price areas where price convergence might raise wholesale prices). GB is a high price area within Europe and has hence been keen to integrate its electricity market with that in northern Europe. However, this work of integrating national markets in Europe has been a slow process, particularly, in the area of ancillary services where it remains a work in progress.

5. Retail margins

The other main component of the industrial price that is competitively determined is the retail margin. This is the mark-up on top of all of the other cost elements – wholesale prices, network charges and taxes and levies - that retailers add to cover their own costs.

So, what do retailers (suppliers) do in GB? They contract for wholesale power in spot and forward markets, hedge their physical contract position with financial contracts, meter the consumption of their customers, advertise and switch customers, provide customer services such as electrical equipment testing and monitoring and decide on and offer retail tariffs. It is important to understand that in fully liberalized power markets retailers bill for the full price of power, pay regulated transmission and distribution charges to network companies, accept and manage the non-payment risk of final customers, fulfil any social obligations

[33] See Ofgem (2016) as an example of regulatory concerns about market liquidity.
[34] See Pollitt (2018a) for a discussion of the development of the single electricity market in Europe.
[35] See Mansur and White (2012) on the benefits of extending the PJM market.

imposed on tariffs (e.g. low use tariffs) and promote energy efficiency (e.g. via schemes like Carbon Emissions Reduction Target (CERT) and Energy Company Obligation (ECO) in GB)[36].

The GB retail electricity market was opened in stages via the removal of retail 'supply' price controls[37]: from 1990, 1 MW+ customers could choose supplier; from 1994, all 100kW+ customers could choose supplier (i.e. all half hourly metered customers); and from 1998-99, all customers (i.e. non-half hourly metered) could choose supplier. As market opening progressed significant horizontal and vertical (with generation) reintegration occurred involving retail companies, as noted above. A very significant driver of competition was the entry of the former gas monopoly, British Gas, into the electricity market. By 2002 it was the largest supplier of electricity.

There has been significant market innovation since 1990: many final customers (~ 40% (i.e.~10 million consumers)) have dual fuel – electricity and gas - direct debit tariffs; and there are a wide range of fixed, capped, green, social tariffs available in the market. However, the regulator has been concerned about state of supply competition (see Haney and Pollitt, 2014). Ofgem launched a Competition Probe in 2008 following large price increases – which were primarily due to commodity price rises - finding no evidence of cartels but introducing new protections for vulnerable customers. These concerns resulted in the Retail Market Review in 2011, and this eventually led to the energy markets (electricity and gas) being referred to CMA – the general competition authority - in June 2014.

There have been important developments with retail competition in electricity. In Europe EU directives on unbundling have been very significant in promoting retail competition and competition from gas incumbents has been important for stimulating retail competition generally in electricity markets. Small and medium sized companies (SMEs) have been inactive in the retail market (as they often consume less electricity than a typical household) and this market segment has been subject to some limited re-regulation of retail tariff, following CMA 2014-16 inquiry. There has been an ongoing concern in some countries about degree of separation between retail and distribution businesses. New Zealand (in 1999) and The Netherlands (in 2006)[38] have ownership unbundled networks from retail. Texas and the UK have widespread voluntary ownership unbundling of networks and retail. The evidence from New Zealand seems to suggest that residential competition is significantly promoted by smart meters, which have brought down the time taken to switch (and the accuracy of switching) between retailers significantly[39].

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[36] See https://www.ofgem.gov.uk/environmental-programmes/eco/overview-previous-schemes (Accessed 27 November 2018) for more information.

[37] See Henney (2011).

[38] See Nillesen and Pollitt (2011) for a detailed analysis of the impact of ownership separation of the electricity distribution business from retail electricity in New Zealand.

[39] Monthly switching has more than doubled in New Zealand since the roll-out of smart meters began. See the statistics at:
https://emi.ea.govt.nz/Retail/Reports/Tagged/consumer-switching?_si=v|2
Accessed 27 November 2018.

Some overall lessons from the retail competition experience in GB (and generally) can be identified. There has been an active market for larger non-domestic customers with smaller commercial customers regulated initially. There are concerns about small non-domestic (as well as domestic) customer inertia due to a lack of materiality or split incentives (between the bill payer and user) in buildings. There are worries about distorted incentives towards smaller retailers who have been exempted from certain social / energy efficiency obligations, and are hence able to undercut larger retailers unfairly by setting prices which are below the 'competitive' price. Retailing is increasingly about collecting revenue to pay government imposed charges, which increases relative risks for larger more responsible retailers, who correctly allow for non-payment risk. New retailers can target larger more credit worthy customers, but this leaves incumbent retailers with customers who are less attractive to new suppliers or who are less able to pay off their existing bills to facilitate a switch between retailers, putting incumbents at a further disadvantage.

There are a number of lessons for China from GB's experience with a competitive retail electricity market. Stand-alone retailers have struggled with the risks of buying short in spot and monthly markets and selling long – most customers sign up for one year fixed price contracts and some retailers have exited. This is not necessarily a problem (some such retailers have done well and there may be real advantages to vertical integration) but it is a challenge for such retailers. China's new retailers (e.g. in the Guangdong market pilot) are not doing retail as in GB because they do not bill the customer for the full cost of their electricity. They are more like energy service companies advising customers on purchasing cheaper wholesale power (most payment risk remains with the local grid company that continues to bill the final customer). Ideally, existing incumbents should be able to compete in a genuine retail market. One way of doing this might be to create retail businesses at the provincial, or sub-provincial level within SGCC and CSG and allow these retailers to compete within and across their current geographical limits.

Retail competition limits do not have to (and should not) limit the size of the wholesale market. Although the retail market in Great Britain opened up to full competition gradually, retailers purchasing electricity on behalf of their regulated customers still participate fully in the wholesale market. Thus, China needs to find a way of getting regulated customers into the wholesale market (e.g. via procurement auctions for default contract retail customers). Future smart energy retailing business models that combine retail contracts, energy equipment sales and maintenance and energy data analytics will require sophisticated retailers (as can be observed in Great Britain) able to offer integrated solutions including metering and use of meter data.

Genuine retail competition helps with the discovery of the diversity of customer preferences. Thus customers can reveal preferences for their payment method (e.g. monthly, annually), the kind of tariff they want (e.g. green or brown) and their willingness to accept different tariff structures (e.g. flat tariffs, peak pricing, time of use, or real time prices). Over time, retail competition reveals what sorts of advertising methods are acceptable (e.g. door to door selling of residential tariffs was restricted in the UK) and social concerns about tariff fairness.

6. Regulated network charges determination

Before discussing each of the regulator determined elements of the industrial price we need to discuss the general background to how are network charges – for both transmission and distribution - determined in GB.

The total level of revenue allowed to be recovered is set by the regulator for both transmission, direct system operation costs and distribution related charges. Approved tariff methodologies then apportion this total among different customer groups to set individual prices for these services that form the charges that retailers pay on behalf of their customers. The basics of the process by which total revenue for transmission and distribution are derived are similar, we consider this first. The UK uses ex ante regulation and sets a base revenue formula and associated quality of service incentives for a fixed period in advance. This gives rise to strong incentives to perform against the formula.

Ofgem, the independent energy regulator, is responsible for network charges and these are determined without direct reference to the central government. Ofgem is an Independent Regulatory Agency (IRA) with list of statutory duties. Independence involves the fixed term appointment of its CEO, chair and board consisting of executives and independents. Its primary functions, laid out its governing legislation, are: the promotion of competition and non-discriminatory access (as agent of competition authority) to the grid; the regulation of the level and structure of network charges (Ofgem oversees periodic price control review process); and independence to ensure investor interests are protected and arbitrary government interference is made more costly.

It is important to emphasise that Ofgem is a creature of legislation (Electricity Act, Gas Act, Competition Act) and it is, largely, independent of government. Although its board members are appointed by Secretary of State for Energy, the regulator answers to Parliament. It is intended to be an independent voice for economic analysis of the interests of electricity consumers. This is a key safeguard for company shareholders. For instance, if a future government wanted to renationalise some of the companies and/or sequestrate private investment, it will be the independent regulator – assuming it initially remains in place - that will likely identify the detriment to consumers of any reneging on commercial agreements. Its decisions are subject to appeal. Companies and affected 3rd parties can appeal decisions to the Competition & Markets Authority (also largely independent of government) or seek judicial review of process (from the independent judiciary). It is duty bound to consider the need for licensees – generators, network companies and suppliers - to fund the obligations upon them. This is not a guarantee that any company costs will be covered but a general assurance that efficient costs will be covered. For monopolies in the sector (such as the network companies, Ofgem attempts to simulate competition (with the use of rewards as well as penalties).

Ofgem has a significant budget and resources: £90m in 2017-18[40]. It has a benefit cost ratio of 87 to 1 (by its own calculation![41]). It has 816 staff, of which 401 are in regulation, 273 in E-Serve, 142 in corporate functions. E-serve, administers various government programmes towards energy including energy efficiency, renewables support and social programmes (including ROCs, FITs, ECO and WHD). Ofgem raises money from licensed electricity companies and administration fees and is self-funding. It is subject to a 15% real terms reduction in its own funding by 2019-20 (set in 2015). It is staffed by well-paid civil servants. The importance of appropriately resourced regulators in successful electricity market reforms is emphasized in Pollitt and Stern (2011).

Ofgem and its predecessor regulator Offer have accumulated significant experience with the regulation of network companies, where network charges have been determined in successive price control reviews since privatisation in 1990. Distribution price control reviews have (or will) reset prices from: 1995, 2000, 2005, 2010, 2015 and 2023. Transmission price control reviews have (or will) reset prices in: 1993, 1997, 2001, 2007, 2013 and 2021.

Until 2010, price-cap (RPI-X) regulation in GB was explicitly designed to avoid the asset gold-plating that was observed under rate of return regulation, as used in US. It was designed by Stephen Littlechild (the first independent electricity regulator in GB from 1989) for BT (the former monopoly fixed line telephone network operator) to facilitate a transition to a competitive unregulated market and to mimic the effect of competition. Under RPI-X the regulator collects data from the regulated utility on forecast efficient operating costs O_t ; regulatory asset values, including investment plans B_t ; depreciation D_t ; and demand forecasts. It then determines the revenue required: $R_t = O_t + rB_t + D_t$, where r is average cost of capital. Looking at the difference between the efficient level of revenue required and the actual revenue of the firm allows an X factor to be identified which is the scope for annual reductions in revenue. RPI-X refers to the fact that revenue is uprated by a measure of inflation (RPI in the UK) and reduced by an annual 'productivity' factor, X[42].

The basic characteristics of OFGEM RPI-X approach in GB involved fixing the revenue required in a 5-year control period for each electricity distribution company and each electricity transmission company. An initial consultation document was normally issued 18 months before end of current price control period. Several subsequent documents refined the calculation of the required revenue with responses invited each time. Responses were placed in public domain unless marked confidential. A final document was issued by the

[40] See Ofgem (2018b), https://www.ofgem.gov.uk/publications-and-updates/ofgem-annual-report-and-accounts-2017-18

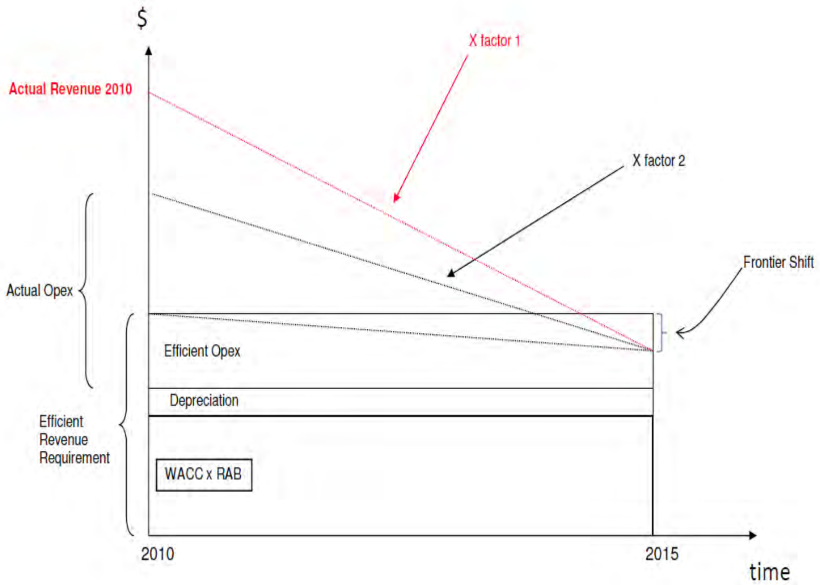
[41] See Ofgem (2018c), https://www.ofgem.gov.uk/system/files/docs/2018/07/consumer_impact_report_-_published0307.pdf

[42] This factor was intended to include all relevant factors which might drive the level of efficient revenue (including the costs of quality, or the relative movement in labour/capital costs vis-à-vis general inflation).

regulator within 6 months of end of current control period. Regulated companies then have one month to appeal to competition authority (originally the Monopolies and Mergers Commission – MMC - and then the Competition Commission - CC) if unhappy with proposals at this stage.

There a number of key factors in the price control process. These include the regulatory asset base (RAB), on which the company is allowed to earn a return. Establishing an initial value for this is difficult, but subsequent updating is relatively straightforward on the basis of agreed additions to the capital base and allowed depreciation. The allowed rate of return or weighted average cost of capital (WACC) is calculated depending on the appropriate risk factor and gearing ratio. The efficient level of operating expenditure (OPEX), which may be subject to capital expenditure (CAPEX) trade-off. And CAPEX itself which requires careful auditing as to whether the proposed investments are both necessary and being efficiently done. Figure 4 shows a regulated firm with starting revenue in 2010 against its efficient level of revenue and different scenarios for X factors to reduce its revenue to the efficient level by 2015.

Figure 4: The impact of X factors on the revenue of a regulated firm



A central part of the regulation of the required expenditure of the regulated company has been the benchmarking of the actual performance. This requires a set of comparable companies, and enough data to identify important cost drivers. It is also important to predict the movement in the frontier level of performance over the upcoming price control period. The regulator in setting prices therefore needs to: identify a comparator group of firms; identify a range of efficiency measurements; identify the inputs, outputs and environmental variables to be taken into account of in the analysis; collect data on consistent basis; conduct the analysis; generate efficiency differences; generate efficient cost predictions for each firm; and set X on the basis of the difference between actual and efficient costs.

A difficult part of setting network charges is getting the right incentives for investment. Benchmarking has been used extensively for opex, but it is hard for capex. This is because capex is lumpy and the exact timing of when it should be done can be difficult to predict in advance. Ofgem have scrutinized investment plans of the companies and approved a baseline level of capex with incentives to economise on actual capital expenditure using a form of menu regulation and cost sharing.[43] This involves companies that accept a lower baseline revenue getting stronger incentives to cut their costs, whereby they keep a larger share of any savings relative to the baseline[44].

It is important to reiterate that Ofgem has employed ex-ante (incentive) regulation, where revenue formula are set in advance and companies have an incentive to deliver services efficiently (at low cost) and at high quality (because various quality measures -such as customer minutes lost - are also subject to baseline quality targets which if exceeded allow the company to increase its revenue)[45]. This is the best simulation of competition. There are strong incentives to outperform ex ante revenue allowances. Companies can improve returns to shareholders within each regulatory period. This also reveals information for regulators to better set allowances and pass efficiencies to consumers in the next regulatory period. This system removes regulatory uncertainties and overheads inherent in ex-post regulation (and the risks of regulatory micromanagement). It gives scope for innovation in opex, capex and financing costs together with internalised outputs. However the revenue formulae are tricky to set and there remain future uncertainties (especially with respect to climate change and climate policy) and a large information asymmetry between the private knowledge of the regulated companies and the regulator.

As we will document later the RPI-X regulation of transmission and distribution charges was very successful in GB. However the system was changed in 2010. The background to this change was changing circumstances (Pollitt, 2008), including: rising investment needs in electricity distribution (+48%, 2005-10 vs 2000-05) and in electricity transmission (+79%, 00-05 vs 07-12); network tariff charges being increasingly driven by capex not opex; and network capex being increased by rising amounts of subsidised renewables connected to the system. A review was announced by Ofgem in 2008 – the RPI-X@20 review (see Ofgem, 2009c) - focussing on customer engagement, sustainability and the scale and scope of innovation. The result of this review was a new system of regulation called RIIO: Revenue = Incentives + Innovation + Outputs. Under RIIO there was more emphasis on incentives, promoting network innovation and on a wider range of outputs (such as stakeholder satisfaction). Notable changes included more money for innovation, a longer price control period (8 rather than 5 years) and a greater emphasis on total expenditure (Totex) not just capex and opex. However, RIIO is more of an evolution of RPI-X than a revolution in the way network charges are determined.

One interesting observation for China is that Great Britain does have some cross-subsidies between areas in transmission and distribution charging. These always exist within a single

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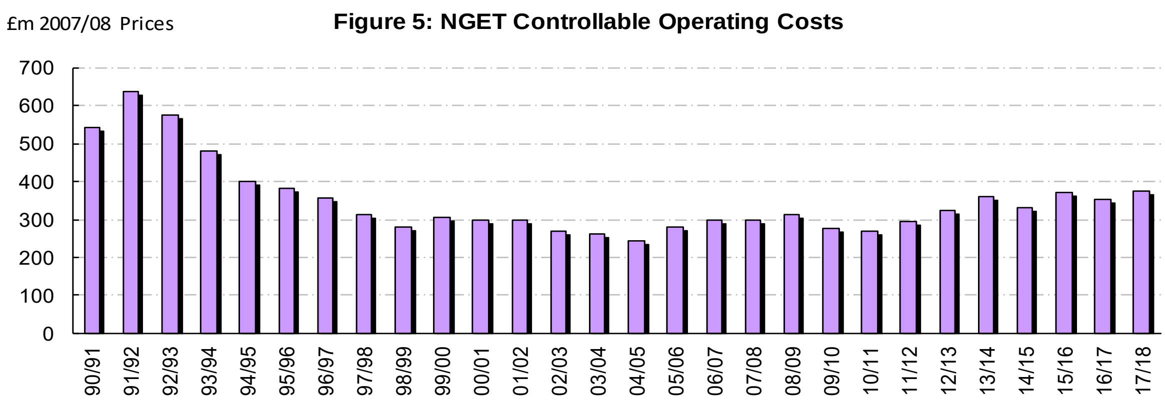
[43] For a description of Ofgem's regulatory process for electricity distribution firms, see Jamasb and Pollitt (2007).
[44] See for an example of the menu regulation scheme, Ofgem (2009a, p.120).
[45] See for a discussion of quality incentives, Ofgem (2009b, p.63).

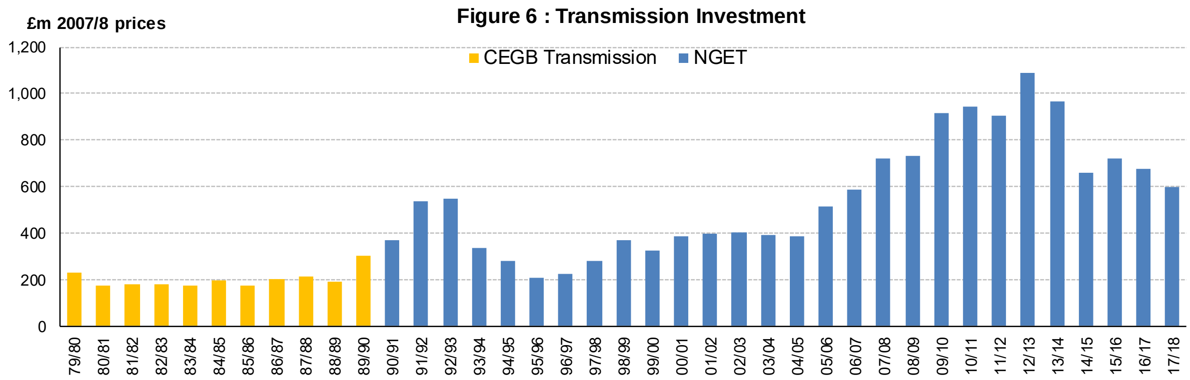
service area (e.g. within UK distribution network operator (DNO) areas and the regions of Guangdong). Transmission and distribution charges are not fully cost reflective in this sense. However, in the UK they are not aimed at promoting economic development in underdeveloped regions as in China. It is a good idea not to distort the market elements of the electricity price to deliver a locational cross-subsidy. It is better to use transmission and distribution charges to do this. This is easy to administer and pass on to customers, the difficulty is that it may distort connection location decisions. Another way to deliver lower electricity prices to particular regions is to simply levy a per MWh charge on everyone and reduce final price of electricity for customers in the favoured region, however it is more difficult to ensure pass through. At the provincial level in China, one or other of the trading provinces could tax imports/exports of cheap electricity to finance the cross-subsidies. For example, Guangdong could tax hydro imports from Yunnan, or Yunnan could tax exports to Guangdong. These taxes would raise revenue without distorting the wholesale price, and the revenue could be used to subsidise electricity sales to favoured areas.

7. Transmission charges

RPI-X regulation was very successful in reducing transmission charges. These fell by around 40% between 1990 and 2005 as a result of gently rising demand, falling operating costs and modest capital expenditure. Figure 5 shows the reduction in real operating costs at National Grid Electricity Transmission (NGET), the largest transmission company in GB (accounting for around 80% of total GB transmission revenue). Figure 6 shows the evolution of real investment at NGET over the same period, which has been financed successfully in the privatized company.

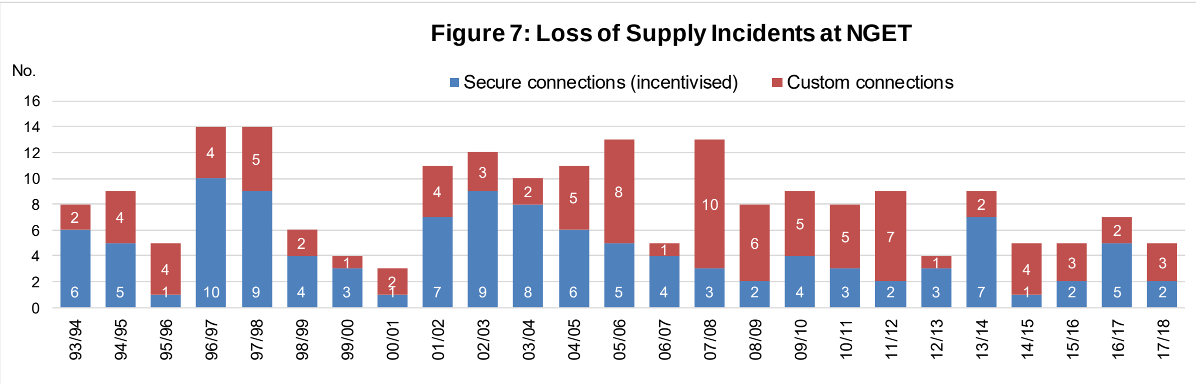


Source: National Grid

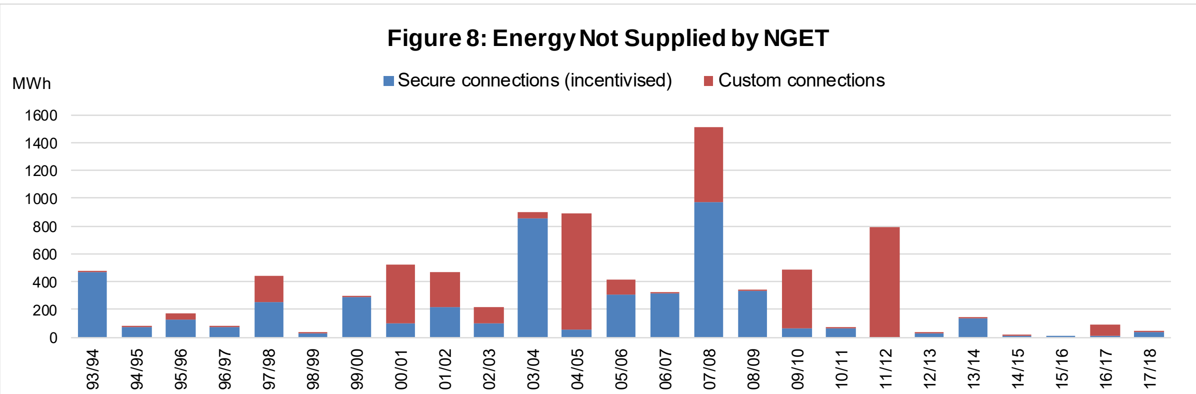


Source: National Grid. Pre-1991 figures are based on CEGB information sources, and are adjusted to reflect one-off investment in the GB-France interconnector.

Meanwhile the transmission system has remained very reliable, with no increase in loss of supply incidents (Figure 7) or in energy not supplied (Figure 8). Note that total supply is of the order of 300 TWh, so the level of energy not supplied is trivial.



Custom connections are for certain industrial customers who accept higher levels of interruption in return for lower tariffs.
Source: National Grid



Source: National Grid

Overall transmission company revenues are determined by the regulator as discussed in the previous section. The charges which customers of the transmission system pay are paid via: connection charges, which are charged to generators and loads/distributors; transmission use of system charges (TNUoS), which are charged to generators and loads (generators pay per MW and loads pay per MW and per MWh); and international interconnector charges, which are largely paid for by users via arbitrage revenue. Transmission losses are recovered via a transmission loss multiplier which adjusts metered volumes (allocated 45% to generators, 55% to retailers), calculated by Elexon. There are incentive payments for quality of service. We discuss these elements in more detail below.

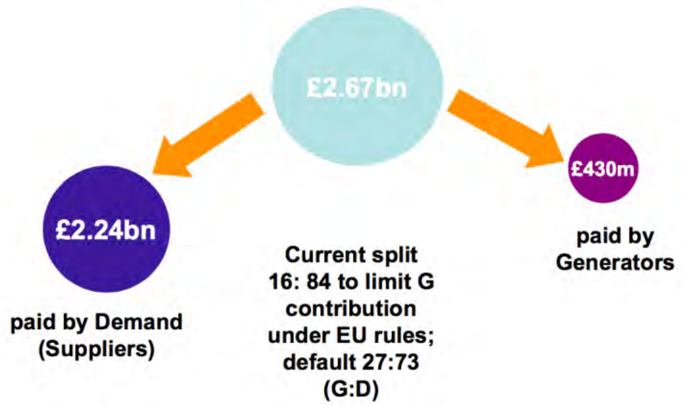
Connection charging is an asset based charge levied on users to recover the costs, with a reasonable rate of return, of providing assets for connection to the GB transmission system. The charges relate to the cost of assets installed **solely** for and only capable of use by an individual user. They are charged by asset, taking account of asset value, asset age, site-specific maintenance and the costs of running the transmission system.

Generation TNUoS charges reflect the incremental cost of facilitating generation on the transmission network: the higher network requirement the higher the charge, this incentivises efficient location. It is charged to all Directly Connected Generation; interconnectors do not pay; but the zonal element is also paid by Non-Licence Exemptible Embedded Generation. Annual Chargeable Capacity is based on the maximum transmission entry capacity (TEC), in zones where the price is negative, the output is taken to be the average of three "proving runs".

Demand TNUoS charges reflect the incremental cost of facilitating offtake from the transmission network: the higher the network requirement, the higher the charge. This incentivises efficient location of demand and/or offsetting distributed generation. It is charged to all offtakes, but international interconnectors do not pay. Annual Chargeable Capacity is based on half-hourly metered consumption. This is assessed on the "Triad" which equals the average of consumption in the 3 half-hours of largest system demand between November and March separated by 10 days. Half-hourly metered consumers can reduce off-take charges by managing demand in ~20 likely peak demand periods per winter. Non-half-hourly metered consumption is charged based on energy taken between 16:00 and 19:00 throughout the year.

The current split between generation and demand charges is shown in Figure 9.

Figure 9: TNUoS 2018/19 Regulated revenue



Source: National Grid

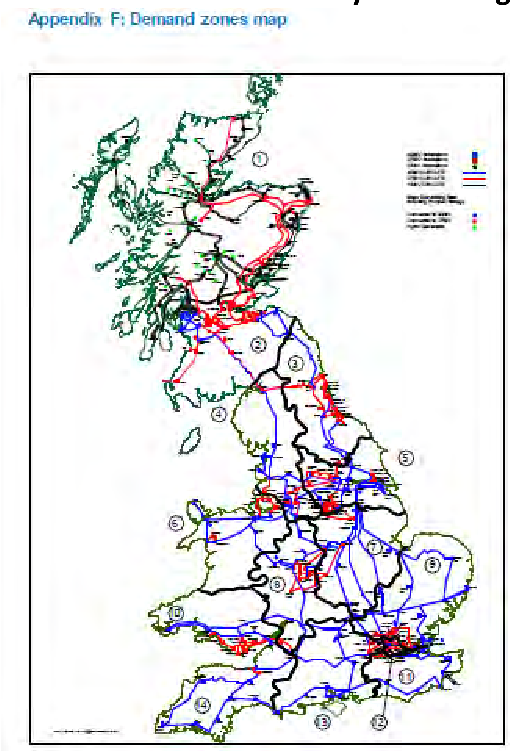
The calculation of the price signal in the zonal charging for transmission capacity is built up as follows: take a base network; adjust for the winter peak, contracted generation and forecast demand; measure the flow on each line and the total MW (Tm); **a**dd a MW on at each node and observe the new flow MW (Tmn); calculate nodal cost of accommodating the increase, Tm – TMn = Ti (MWkm); applying an historic cost of providing a MWKm, £/MWkm expansion constant (EC); use this to calculate TNUoS and cost per MW, Ti x EC = £ / MW; and group into zones for actual charging. The generation TNUoS zones are shown in Figure 10 and the demand TNUoS zones are shown in Figure 11. The current tariff rates vary considerably by zone. In 2018-19, it will cost a generator £20.89 / kW to be connected in the north of Scotland, but it would be paid £11.26 / kW if it was connected in Greater London.[46] Similarly, a load connected in Greater London would pay £54.91 / kW, against only £26.30 / kW in the north of Scotland.[47]

[46] See National Grid (2018, p.13).
[47] See National Grid (2018, p.8).

Figure 10: Generation Transmission Use of System charging zones in GB

Source: National Grid (2018, p.47).

Figure 11: Demand Transmission Use of System charging zones in GB

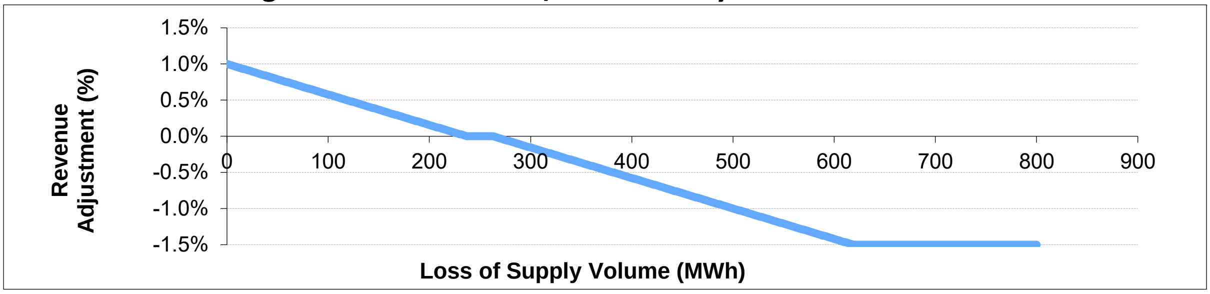


Source: National Grid (2018, p.48).

The reconciliation between the allowed total revenue (in the previous section) with the revenue actually raised is as follows. The annual tariff is determined in January before relevant charging year starting April. It seeks recovery of allowed revenues (and best endeavours not to exceed allowed revenues). It is based on a forecast of the charge-base (TEC, half-hourly metered triad demands and non-half-hourly metered demand). Users are initially charged monthly on the basis of the forecast charge-base. These revenues are subject to reconciliation with the actual demands/consumption as the energy market settlement is finalised. The tariff values are not adjusted. Total revenue from reconciled charges may be larger or smaller than the allowed revenues. The system operator must reduce subsequent allowed revenues (2 years after the charge year) with interest on any over recovery. Penal interest is payable if actual recovery exceeds 2.75%. The system operator may recover under recoveries (by increasing recovery 2 years after charge year). Interest costs are not recoverable if revenue recoveries are less than 94.5%. If large under or over recoveries occur in successive years, the SO must explain the reasons for this and seek the regulator's permission for corrective actions.

The transmission revenue is subject to a Transmission Network Reliability Incentive. This was **i**ntroduced following high profile interruptions in London & Birmingham in 2003. This is an opportunity to earn up to 1% additional revenue (currently, around £11-12m) for annual loss of supply below the annual average. It includes the potential to lose up to 1.5% revenue (£17-18m) for annual loss of supply above the annual average. The nature of the incentive is illustrated in Figure 12.

Figure 12: NGET's 2008/09 Reliability Incentive Scheme



Effective value of lost load initially ~ £50/kWh

Source: National Grid

International interconnectors are regulated differently and their regulation has evolved somewhat over time. In 2001, the French interconnector (IFA) was separately licensed (from the onshore transmission system) requiring: non-discriminatory regulated 3rd party access (RTPA) with "Use it or lose it" access rights; and compliance with European Union (EU) "use of congestion revenues" requirements which means capacity sales revenues not required for "guaranteeing availability" must be returned to national TSO charge-payers. In recent years, Ofgem have decided that IFA revenues are exceeding that needed to guarantee availability and have imposed a cap and revenues sharing mechanism. In the mid 2000s, BritNed (linking England and the Netherlands) was conceived of as a merchant interconnector project through a National Grid and TenneT joint venture. This cable is therefore owned by the incumbent onshore transmission companies at either end, but separate from their regular transmission system operator (TSO) activities. It finances its capital and operational costs from implicit and explicit capacity sales. As part of securing an exemption from the EU use of congestion revenues requirement, the European Commission required a cap on the returns achieved (measured over 25 years of planned operation).

National Grid and TenneT agreed to continue the project despite the asymmetric return prospects (a cap on the maximum revenue, but no guaranteed minimum revenue).

Other interconnectors have been subject to different arrangements. The Northern Ireland to Southwest Scotland (Moyle) transmission link was built and operated by a company funded by Northern Ireland transmission charge-payers (capacity sales reduce charge-payer costs). The Ireland-England (East-West) interconnector was built by the Irish Electricity Supply Board as a TSO regulated asset funded by Irish transmission charge-payers. For new links to Belgium and Norway, National Grid and partner TSOs worked with regulators to make a hybrid regulated/merchant arrangement such that there is a broadly symmetrical cap and floor on sales revenues. Other companies are considering interconnectors (e.g. ElecLink plan to use the Channel Tunnel). They have indicated they will use an asymmetric capped merchant model.

We can make some observations on locational pricing & cost-reflectivity of transmission charges in GB. GB has not so far adopted locational marginal prices (LMPs) to reflect short run transmission network constraints[48]. In-line with the initial primary role of National Grid as a 'wire provider' in England & Wales, the initial charging methodology allocated allowed revenues to the degree users made transits across key boundaries. A review of transmission charging in 1992 identified merits in signalling short-run marginal costs but decided to signal long-run (investment cost-based) marginal costs on the basis of consistency with National Grid's role as a 'wire provider' and practical issues.

These practical issues included the following. The fact that in 1992 the extraction of short-run shadow prices from the complex scheduling and dispatch Pool software - in use at the time - was non-trivial. Peak network power flow patterns were relatively stable and this facilitated long-run use and network need predictions. Market parties wanted a transparent and stable tariff for at least the next year. Improving long-run signals were judged adequate for informing the location of CCGT new entrants. The incremental benefits of short-run signals were initially calculated to be moderate in a centrally dispatched market. Distribution charging follows a broadly similar long-run (investment cost-based) approach (but considerably different in detail). The introduction of generation and storage self-dispatch (with NETA), the development of variable wind, higher market driven interconnector flows, an active demand side and increasing internal congestion in the network – due to increasing renewables - mean the case for short-run signals is increasing and a further review is imminent.

Some important lessons for China from the GB experience with transmission charging include the following. There is some value in charging some transmission costs to generators to focus incentives on generators, rather than indirectly via loads. Locational signals can be delivered to incentivise the location of generators and loads via zonal charges or via locational marginal prices (LMPs). LMPs are volatile and may not be as good long term signals as zonal transmission charges. Though the existence of the ability to trade financial transmission rights (FTRs) does mitigate some of the financial risk associated with LMPs. History, even in LMP jurisdictions, suggests zonal charges should be implemented first as a

[48] For discussions of locational marginal prices see Bohn et al. (1984) and Hogan (1992).

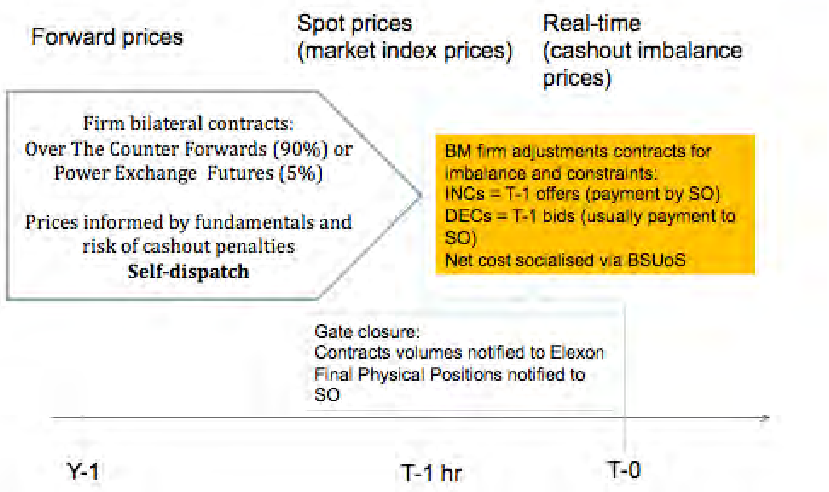
stepping stone to LMPs.[49] LMPs do not solve the residual transmission pricing problem. There is still a need to recover most of the fixed cost of the transmission system via another charging mechanism.

8. System balancing charges

Within the overall industrial price of electricity, the charges for system operation in GB covers all of the costs incurred by the system operator. These consist of internal (staff and IT) costs (very small, c.£100m per annum) and the external (procurement) costs which could be as high as £850m. Internal costs are subject to price cap regulation, similar to transmission. External costs are subject to market testing and incentives for their overall minimisation. In GB, both are recovered by a balancing service use of system charge (BSUoS) from generation and demand (50:50) per MWh, less imbalance charges (described below) recovered from parties.[50] The accepted bids and offers for energy balancing are published.[51]

The largest component of external system operation costs arises from the balancing mechanism. Figure 13 summarises the place of the balancing mechanism (BM) within the pricing of energy following the end of the Pool in 2001 and the introduction of the New Electricity Trading Arrangements, and the subsequent British Electricity Trading Arrangements from 2005.

Figure 13: The place of the balancing mechanism relative to real time



Source: National Grid

Imbalance, and hence exposure to the balancing mechanism, has to be measured. Market parties register bilateral contract volumes to market & settlement system operator (Elexon) at Gate-closure (t-1 hour). Notifications update relevant (market wide) production and consumption accounts. Physical meters are registered to particular Balancing Mechanism

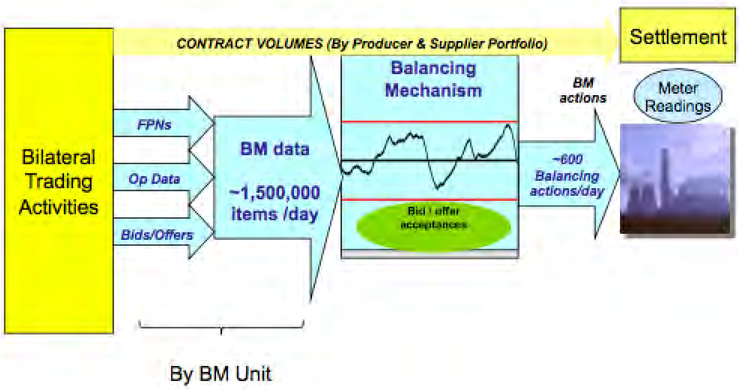
[49] See Pollitt (2012b) on the history of ISOs in the US.
[50] See https://www.nationalgrid.com/uk/electricity/charging-and-methodology/balancing-services-use-system-bsuos-charges
[51] See https://www.bmreports.com/bmrs/?q=balancing/detailprices

Units (BMUs) who include large generators (>50MW) and must have individual BMUs linked to production accounts. Suppliers have a BMU per distribution network all aggregated to a market wide consumption account. Half-hour meters are compulsory for generators and large loads (>100kW). Half-hour meters measure the flow from transmission to distribution networks.

Initial settlement involves metering aggregators summing half-hourly meter values to supplier BMUs and allocating the remaining transmission to distribution system (Tx→Dx) flow to supplier BMUs in-line with supplier customer estimates. Under final settlement: non-half hourly meter readings are allocated to half-hours using one of a number of standard profiles for specific customer classes. Residual error between Tx→Dx flow and supplier BMUs (which include distribution system losses) are allocated pro-rata. Initial 'cashout' settlement (on the difference between initial meter volumes & contract volumes) is undertaken at t+28 days. Final cashout reconciliation (using final meter allocations) is at t+14 months.

The system operator's role in balancing the system is as follows. Notifications of intended physical positions (generation self-dispatch & demand forecasts) to the system operator are separate from contract volume notifications. Initial position notifications are submitted at t-24 hours. These are updated as new information emerges until the t-1hour Final Physical Notification (FPN). Notifications are location specific to the Balancing Mechanism Units (BMU). The system operator will make national demand forecasts which suppliers may use to make their individual notifications. Market parties may also post Balancing Mechanism offers (increase power to system) and bids (reduce power to system) specifying the BMU of delivery – usually in pairs. The system operator acceptance of a bid or offer is a firm contract (generally no cancellation). Unwinding of a BM contract is by expiry of instruction or acceptance of a reverse trade. The system operator has discretion to trade energy with the wider energy market for physical balancing purposes (the SO is prohibited from making any speculative financial trades) and to procure specialist balancing services (ancillary services) using various platforms. The net energy position of system operator is the market net imbalance volume (NIV). Figure 14 shows the flow of information in balancing and settlement.

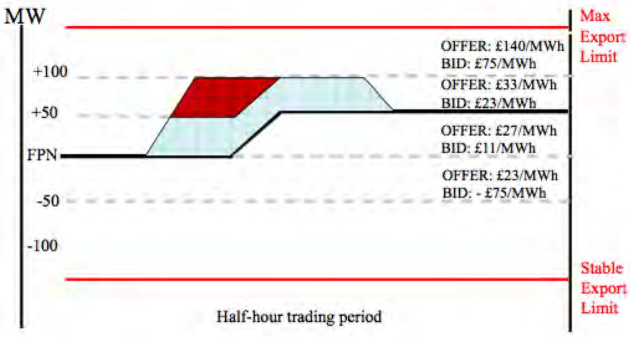
Figure 14: Balancing market information flows



Source: National Grid

Figure 15 shows the bids and offers for one BMU that is offering to go up and bidding to go down in 50 MW increments, at given deviations from its FPN position. Initially it is offering to go up 50 MW for £27/MWh or to go down by 50 MW for £75/MWh. All the bids offered in the BM must lie within the maximum export limit (or generator and transmission equipment might be damaged) and the minimum stable export limit (so that minimum stable production levels are exceeded).

Figure 15: Bids in the balancing mechanism

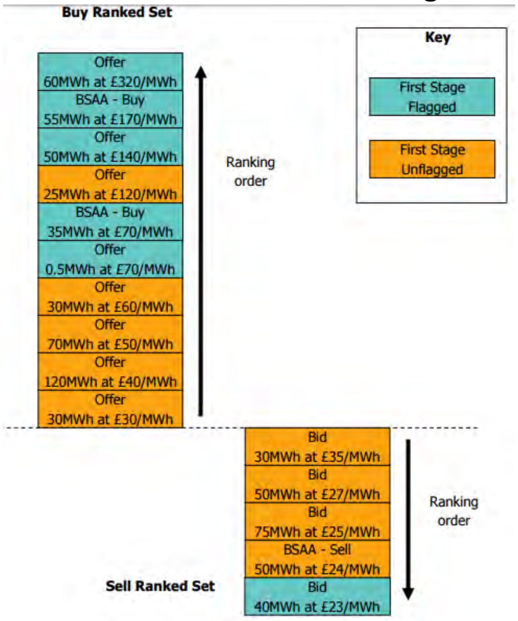


Source: National Grid.

Imbalance cashout prices are calculated as follows. The system operator will enter many contracts in each half-hour trading period for energy balancing actions and system balancing actions to provide reserve, frequency response capacity and utilisation and congestion resolution. Some system actions will be specifically flagged by the system operator and excluded from imbalance pricing. The remaining buy and sell actions will be ranked in price order. Energy balancing actions are defined as the cheapest actions in the net imbalance volume (NIV) direction. The imbalance price is determined by the average of the most expensive bids in the Price Average Reference Volume (PAR) in the NIV direction. Currently the PAR is set at 50 MWh. An example of ranked up and down bids in the balancing mechanism is shown in Figure 16.[52]

[52] These offers and bids are all of the actions taken by the system operator in a half hour period. The flagged actions in blue reflect actions taken for system specific reasons which could be to do with frequency control or constraint management. The unflagged actions in orange are for energy balancing. The NIV is measured looking at the net impact of all actions taken by the SO. It shows that there were 475.5 MWh of offers and 245 MWh of bids taken, so the market was short by 230.5 MWh. The system imbalance price is the marginal net imbalance offer required to solicit 230.5 MWh of net supply, which in this case is £60 / MWh.

Figure 16: Ranked bids in the balancing mechanism

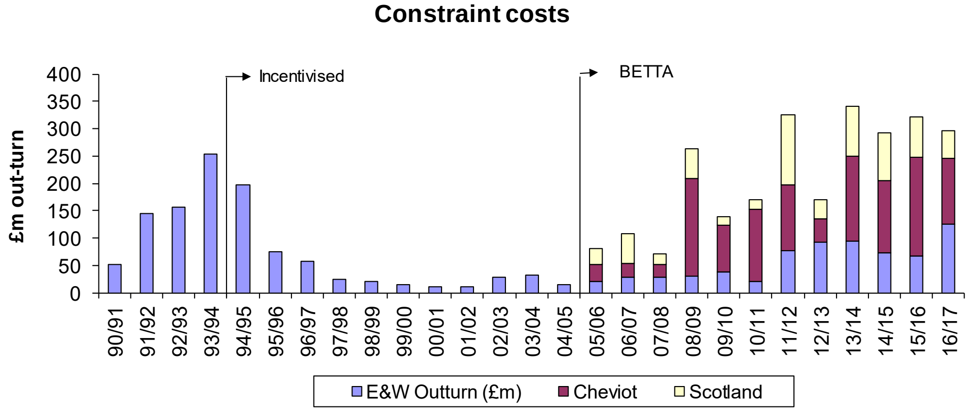


BSAA = Balance Service Adjustment Action
Source: National Grid

System Operator Incentive Schemes ensure that the system operator minimises the external costs it imposes on the system. This applies to intermittent renewable generators who are – correctly - exposed to their greater likelihood of being imbalanced and hence can expect to receive less average revenue per MWh as a result[53]. Initially after privatisation the external (balancing) costs of operating the transmission system were passed through to suppliers and onto consumers without any market actor taking responsibility. As a result, there was a sharp rise in such costs. These costs included: congestion costs, reserve & frequency response, losses and reactive power. Following prompting by the regulator, National Grid bilaterally negotiated an external cost management incentive scheme. The resets of this scheme were subsequently overseen by the regulator. This has resulted in a series of incentive schemes on NGET to reduce operational costs. There was a sliding scale that shares costs & benefits with customers, usually over a short (1 or 2 year) duration. The sharing factors + caps/collars limit risk of negative externalities on consumers and provide some internalisation of consequences of NGET investment and network asset management decisions. Figure 17, shows the evolution of system constraint payments, which initially fell under incentive regulation in England and Wales. These then increased when National Grid's role was extended to cover the whole of Great Britain. Figure 18 shows the evolution of National Grid's entire external costs of system operation over the period.

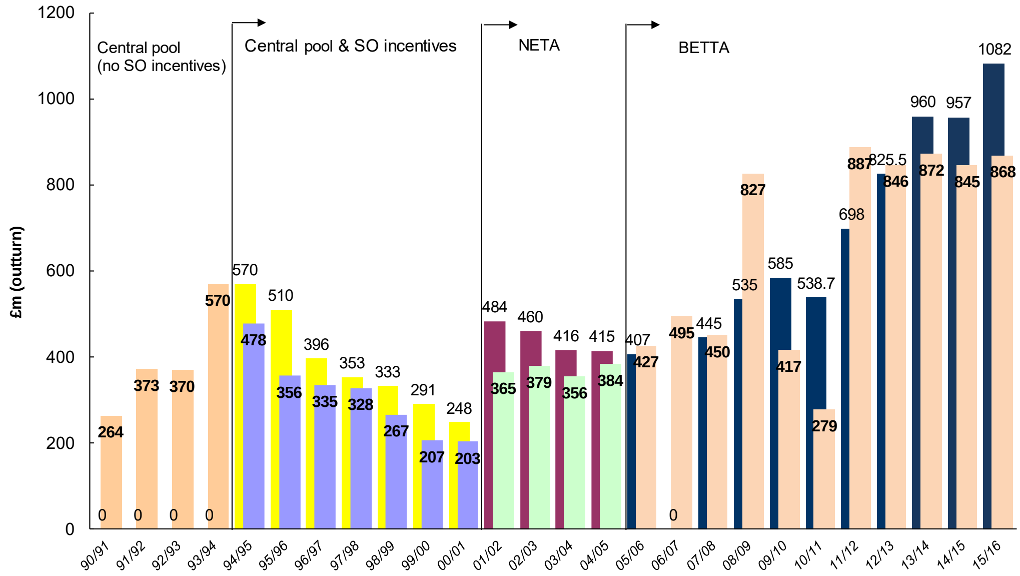
[53] See Newbery (2012) for a discussion of this.

Figure 17: National Grid Electricity Transmission System Operator constraint payments (nominal £)



Source: National Grid

Figure 18: National Grid Electricity System Operation external costs (nominal £)



Source: National Grid

The role of the system operator, National Grid Electricity Transmission System Operator (NGET SO), has developed over time. Pre-privatisation (i.e. before 1989) it involved real-time operation of CEGB (in England & Wales) generation and transmission assets. From 1990-1994 the England & Wales transmission system operator provided a central dispatch agency service to the market. From 1994-2000 it was a transmission system operator and central despatch agent with exposure to balancing costs. From 2001-2004 the New Electricity Trading Arrangements were in operation (with self-dispatch market) and the balancing incentive remained. From 2005- the British Electricity Trading & Transmission Arrangements have been in place (Scotland joins NETA). This, additionally, made National Grid responsible for system operation and balancing in Scotland. From 2014- NGET SO was appointed Electricity Market Reform delivery agent (which includes the administration of the central government Capacity Mechanism and low carbon Contracts for Differences). In

2015 NGET SO was given enhanced system planning responsibilities following Ofgem's Integrated Transmission Planning & Regulation Project.

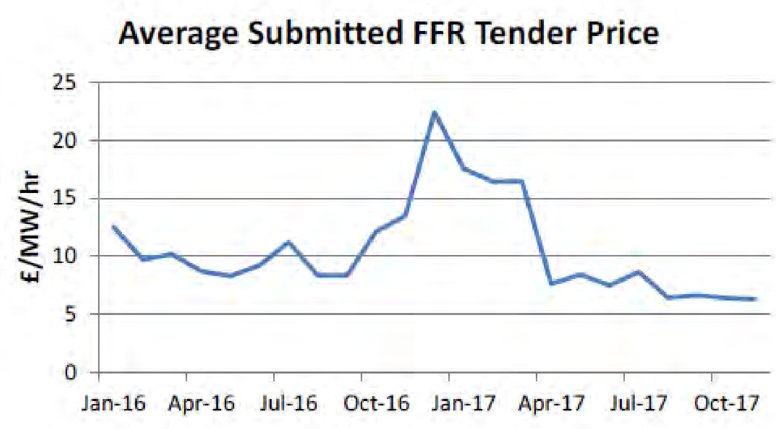
As of mid-2018, National GrId is planning to place the system operator in a wholly separate company from 2019. Anaya and Pollitt (2017) have made a number of recommendations to Ofgem about how this more independent system operator might be regulated, drawing on the experiences of independent system operators (ISOs) in the US, South America and Australia. Good regulation involves not only assessing the efficient amount of revenue that the ISO requires but also ensuring the efficiency of its procurement methods (market-based) and system optimisation (procurement levels). Stakeholders (generators, network companies, retailers and customer groups) play a key role in the proposal and design of detailed implementation rules for new initiatives for the best ISOs. Sophisticated voting rules are observed and are worthy of study for the lessons they might have for GB. A high level of internal and external oversight of ISO decision making is observed which is becoming more complex and subject to high levels of uncertainty. In electricity, US ISO *State of Market Reports* provide excellent examples of regular updates on key recommendations for future market design.

A recent issue that has arisen in system operation in Great Britain is the efficiency of the procurement of ancillary services by the system operator. Typically, the GB SO has 3-5 GW of reserve contracted a day ahead. For example, it procures a large number of ancillary services under different procurement mechanisms. It uses auctions (pay-as-bid) for balancing market (BM), firm fast response, short term operating reserve (STOR), STOR Runway, enhanced optimal STOR, firm frequency response (FFR) (primary, secondary and high), enhanced frequency response (EFR). It uses bilateral tenders for balancing mechanism start up, demand turn up, mandatory frequency response, frequency control by demand side management (DSM), FFR bridging contracts, transmission constraint management, contingency balancing reserve, max generation, intertrips, black start and SO to SO transactions. In addition, some services such as reactive power are procured at fixed prices.

As these lists indicate there are a large number of ancillary service products. In 2016 there were 30 ancillary service products in GB, now reduced to around 22. However questions have been raised as to whether this could be reduced further (perhaps to just four: reserve, security, frequency and voltage support). Greve at al. (2018) discuss how the ancillary services (A/S) product definition needs to be clarified with too many ill-defined products. The SO needs to justify procurement quantities and express trade-offs transparently. Opportunities for gaming system may well exist and be increasing as the products become more important, especially if there are a lack of penalties for creating A/S demand. Optimal contracts are not currently clear because of the uncertain nature of the counter-party to the SO. Distribution system operator (DSO) - TSO conflicts need to be resolved as DSOs increase their relative ability to supply A/S.

Demand for ancillary services in GB has, apparently, not risen much even though RES share has risen significantly. Meanwhile prices for some ancillary services have fallen recently due to increased competition, including from electrical energy storage (EES) and from interconnectors under conditions of low demand growth. As an example of falling prices see Figure 19.

Figure 19: Falling prices for firm frequency response



Source: National Grid

Recently the government has introduced a capacity mechanism in Great Britain, which is administered by the system operator. Capacity mechanisms have a history in GB. Up until 1989 there was centrally planned capacity to meet 9 winters per century loss of load probability within the CEGB. From 1990-2000 retail companies had a 9 winters per century obligation which could be discharged by purchasing energy in the Pool market. The Pool purchase price = SMP + (VoLL – SMP)*LOLP, where SMP – was the system marginal price (the market clearing price), VoLL was the value of lost load and LOLP was loss of load probability. Capacity was paid VoLL * LOLP.

However, there were concerns that SMP & LOLP are subject to manipulation by generators with market power. In 2001-2004 under the New Electricity Trading Arrangements (NETA), there were only firm bilateral energy only contracts and LOLP obligations removed. This has continued under BETTA. In 2012 Government Energy Market Reform (EMR) identified the need for capacity mechanism. In 2013 Regulator made a final decision on cashout pricing (incorporating a VoLL). From 2013 on, the Supplemental Balancing Reserve (SBR) and Demand Side Balancing Reserve (DSBR) were introduced to provide extra winter capacity. These schemes paid for additional emergency capacity. In 2014 the capacity market began with a t-4 years-ahead auction (for winter 2018/19) which cleared at £19.4 / kW.[54] However the most recent auction in 2017 the t-4 auction cleared at £8.40 / kW.

The developing experience of GB offers a number of lessons for China. The system operator function is important in that it lies at the heart of the system. The SO needs an incentive to manage its own internal costs. In GB, the SO has internal revenue of £140m p.a. subject to a 50% incentive rate. It is even more Important to incentivise the SO to procure external services efficiently. In GB, the external costs are c.£850m p.a. Now subject to +/-£30m stakeholder panel determined incentive.[55] The SO does not need to be integrated with

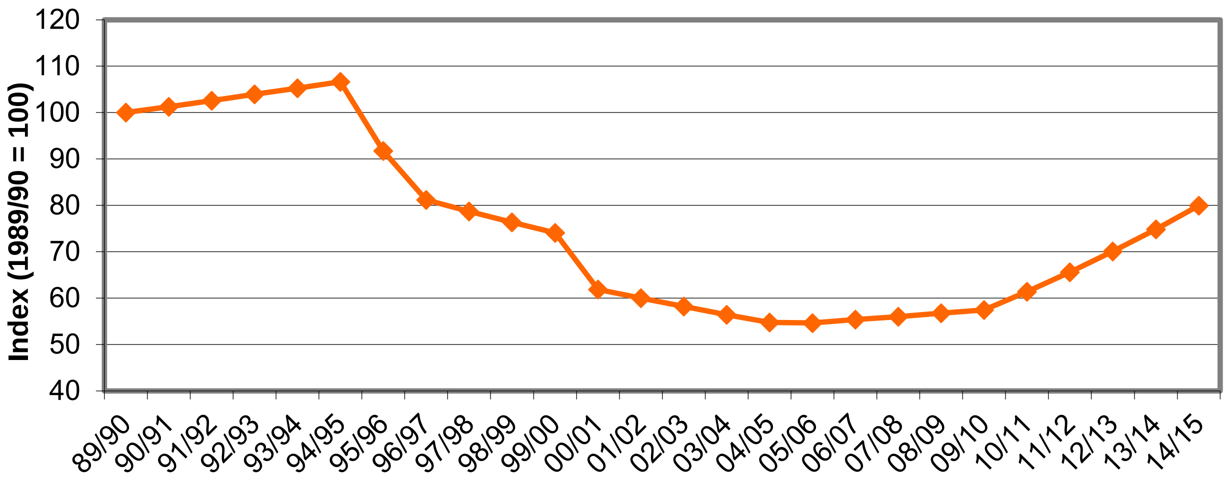
[54] There are t-1 years capacity auctions as well.
[55] See Ofgem (2018d), https://www.ofgem.gov.uk/system/files/docs/2018/02/policy_decision_on_electricity_system_operator_regulatory_and_incentives_framework_from_april_2018.pdf

transmission operator (TO) to function effectively. SO functions are increasingly subject to competition and market testing. The work of co-optimising wholesale energy and ancillary services markets[56] (and indeed further co-optimising across wholesale power markets and network investments) remains an important work in progress in all advanced electricity systems.

9. Distribution charges

Incentive regulation of distribution charges has led to a very strong relative reduction in distribution charges. Between 1995, when charges were first reset by the regulator and 2005, prices fell by around 50% for the average distribution company in England and Wales and by more in some areas (e.g. SWEB in the south west of England).[57] The reduction being larger than in transmission charges in England and Wales. At the same time quality of service improved substantially, with average customer minutes lost falling from over 100 minutes per year in 1990 to around 30 minutes today. Figure 20 shows the fall in real distribution charges.

Figure 20: The development of real distribution revenue since privatisation average DNO in England and Wales



Source: National Grid

It is important to stress that overall revenues for distribution companies are determined by the regulator as discussed in section 6 above. They are then charged out to individual customer groups in each distribution company area via a common charging methodology.

[56] See Anaya and Pollitt (2018) for a discussion of co-optimisation.
[57] Domah and Pollitt (2001) find significant gains for society following the privatisation and incentive regulation of the regional electricity companies (RECs) that owned the distribution and incumbent retail assets.

Connection charges are charged to generators and loads/distributors according to which is requesting connection and to cover sole use assets. Generators need to contribute to the cost of upgrading the distribution system up to the next substation at the voltage level at which they are connected (so called 'shallowish' connection charging). Similar to transmission use of system charges (TNUoS), distribution use of system charges (DNUoS) are charged to generators and loads: generators pay per MW connected and loads pay per MW and per MWh. Most of the revenue of a distribution company is collected from loads and this is disproportionately paid by households. There are strong incentive payments for quality of service (e.g. reducing customer minutes lost) and these can substantially increase the rate of return on a distribution company's assets.

Over recent years, new generation is increasingly connecting to distribution grid (at 132/33kV and below). Since 2011 around 13 GW of solar (all of it connected to the distribution grid) has been connected in Great Britain against peak demand of 54 GW. The charging methodology is substantially based on per MWh charges for smaller customers who are not half-hourly metered. There have been worries that this does not reflect the fixed costs of the network and hence over-incentivises self-generation (and storage).[58] However this might be offset by a managed rise in electric vehicle charging within the distribution network, that does not substantially add to the peak system requirements but makes more use of the existing distribution network.[59]

The future roles of transmission owners, the system operator and the distribution network companies are evolving as distributed generation (DG) increases and demand falls on the national transmission system. Who should have balancing responsibility and how should they fulfil it? There is a potential for distribution companies and third parties (such as customers and microgrids) to take more responsibility in system balancing and other traditional functions of the transmission network and its system operator. Balancing the system can be met by market based solutions or via regulated assets (e.g. should a storage facility be a commercial or regulated asset?). The distribution system has traditionally been a passive network, however the rise of DG means that it is becoming more active. This has led to reactive power (voltage) issues in parts of network, which could be procured locally or mitigated by action of the distribution company. The benefits of any new arrangement need to be proven for customers and some ongoing innovation projects are trialing novel solutions to this[60].

The lessons for China from the experience in Great Britain can be summed up as follows. Distribution pricing is an important component of overall electricity costs and incentive regulation can deliver impressive results. How overall charges are apportioned is very important and potentially highly distortionary in a more active network world. Therefore, there is a need to think carefully about how to deliver locational incentives. Recovering network fixed costs is a major issue for distribution networks, especially for a system where

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[58] See Pollitt (2018b) for a discussion.

[59] See Kufeoglu and Pollitt (2018) for some analysis of the impact of EVs on who pays residential distribution charges in GB.

[60] See for example, National Grid and UKPN's Power Potential Project. The background issues to this project are discussed in Anaya and Pollitt (2018).

passive residential consumers are not shouldering a significant share of network costs at the moment. Technological developments will heighten tariff methodology issues everywhere, including in China.

10. Environmental levies and taxes

There are a number of important taxes and levies which are part of the industrial price of electricity in GB. These are a portion of the main renewables support schemes, namely, the Renewables Obligation (RO), the feed in tariffs (FITs) for smaller generators and contracts-for-differences (CFDs) (which will include nuclear power eventually). In addition, industrial customers contribute to the Hydro-Benefit Scheme, to support consumers in northern Scotland, and pay climate policy inspired energy efficiency charges including the climate change levy / carbon reduction commitment (CCL / CRC) and carbon pricing via the impact on generation prices of EU Emissions Trading Scheme (EU ETS) and carbon taxes in the form of the domestic carbon price support (CPS). We discuss each element in turn.

The RO Scheme is a tradeable green certificate scheme. Suppliers/retailers must present renewable obligation certificates (ROCs) for a percentage of sales. Renewable generators must be registered on the Renewables and CHP register at Ofgem to be awarded ROCs.[61] For instance, in 2014-15, 71.3 million ROCs presented for 1MWh each, this represented 99.1% of the total obligation on suppliers. The administratively set buy out price was £43.30 per ROC. The buyout price set the price for the ROCs presented. The buyout revenue is recycled to actual suppliers of ROCs, meaning that each ROC was worth £43.65 (recycle value was £0.35 plus the £43.30 buy-out price) to a renewable generator[62]. There is an 85% exemption from paying towards the ROC scheme for energy intensive users, but normally it is recovered by retailers per MWh on all loads.[63] The RO scheme closed in 2017 to new generators but it is the most significant renewable support scheme financially.

Small scale FIT payments offer fixed prices per MWh to generators of different sizes (but usually less than 5 MW). The technologies effected include wind, solar, hydro and anaerobic digestion.[64] These were initially very generous for solar, given the rapidly falling price of PV.

CFDs are now the main way by which the UK government supports renewables (and new nuclear). It is set to become significant as projects financed by CFD contracts are completed. There have been auctions for CFD contracts in Feb 2015 and Aug 2017, both of which delivered significant quantities of lower price bids than the previous – interim - administrative CFD prices. In the first auction, winning onshore wind bids were 17% lower than the administrative CFD price and winning offshore wind bids were 18% lower than the

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[61] See https://www.renewablesandchp.ofgem.gov.uk/Public/ReportManager.aspx?ReportVisibility=1&ReportCategory=0
[62] See: https://www.ofgem.gov.uk/environmental-programmes/renewables-obligation-ro
[63] See Grubb and Drummond (2018).
[64] See Helm (2017, p.101).

previous administrative price.[65] In the most recent auction winning bids fell again, with offshore wind projects winning at a price of £57.50 / MWh for delivery in 2022/23.[66] This was against an administrative price of £140 / MWh prior to the first auction, only two and half years earlier.

The hydro-benefit scheme is an interesting cross-subsidy paid by all customers in GB to reduce the high costs of electricity distribution in the region with the lowest population density. Following liberalisation in 1990, the introduction of the wholesale power market threatened to unwind the internal cross-subsidy (within an integrated utility) between the low cost of generation and high cost of distribution in the Scottish Hydro area in north of Scotland. Initially the 'hydro-benefit scheme' taxed the hydro generation and subsidized the distribution charges in the Scottish Hydro area. Later the high distribution cost was covered by levy on all consumption across GB – via the Hydro-benefit replacement scheme.[67]

Industrial customers can be subject to two energy efficiency taxes, which although they are nominally related to climate policy do not tax carbon directly but energy use. The climate change levy (CCL) was set at £5.83 / MWh in April 2018. It is charged to large energy intensive users and is subject to a 90% rebate if voluntary climate change agreement in place. The carbon reduction commitment (CRC) is set at £17.20-18.30 / tonne CO2 in 2018/19 on larger commercial users of electricity to encourage investment in energy management. It is calculated on the deemed carbon content of grid supplied electricity. It has been abolished from 2019.

Carbon Pricing has a significant impact on the industrial electricity price. This happens in two ways, via the participation of the UK electricity sector in the EU ETS and the additional imposition of a carbon tax on fossil fuels used in electricity generation in the UK, via the carbon price support (CPS). The CPS effectively increases the price of carbon emissions from the electricity sector in the UK above that in the rest of the EU. The CPS is part of the carbon price floor (CPF) which sets a target price for the combined EU ETS and CPS price in the UK. It began in April 2013 with a target CPF CO2 price of £30/tonne (in 2009 terms) – forward EUA price + CPS - by 2020 (possibly £70/tonne by 2030). However, the CPS is now capped at £18 /tCO2 (now binding). The CPS directly impacts the wholesale price via raising the price of marginal fossil generation. EUA price currently £14.08 per tonne CO2 (13/07/18). By 2017, the impact of £18 per tonne CPS was enough to push much of the remaining coal fired generation off the system.[68]

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[65] See: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/407465/Breakdown_information_on_CFD_auctions.pdf

[66] See: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/643560/CFD_allocation_round_2_outcome_FINAL.pdf

[67] See DECC (2015), https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/488271/decc_consultation_hydro_benefit_review_22_dec_15__2_.pdf

[68] See Wilson and Staffell (2018).

The combined impact of these levies and taxes on the industrial price of electricity is substantial in Great Britain. A key question for China is the extent to which industrial electricity customers can and should be subject to payments for low carbon generation, energy efficiency and carbon pricing. Some other countries, such as Germany, have exempted much of their industry from bearing the costs of government policy in the electricity sector. This is only possible in systems where industry is a relatively small share of total electricity demand. This is not the case in China. It is right that all electricity consumers pay the true cost of electricity and this includes charges which reflect the externality cost of carbon emissions from power plants or the local environmental benefit of cleaner technologies. However, it remains an open question as to whether some of the cost of the energy transition should be shifted from electricity consumers onto general taxation because the current relatively high cost of renewables is a function of its technological immaturity and hence there is a wider public benefit from the learning by doing effect of subsidy.[69] Energy efficiency policies are wider than just electricity use and hence it is worth thinking about whether payment for these policies are fairly targeted on electricity users, especially when it may be poorer electricity customers that end up paying disproportionately for them.

11. **Overall lessons on price determination for China from Great Britain**

Following the theory of the spot pricing of electricity due to Schweppe and colleagues[70], the price for every industrial customer should vary by location, time, quantity and willingness to accept interruption. However, in the real world of liberalized markets there is much less bill variation than the underlying price components would suggest as final customers value certainty in pricing. In general, the focus in a liberalised market is on what the customer is getting for their money and away from the producer, except in the sense that producer needs a fair return on capital. In an initially profitable system – such as in China - reform should be about rebalancing the electricity system away from producer to consumer interests, i.e. from inefficient costs and high profits towards cheaper, cleaner and more reliable electricity supply.

There is a key role for the profit motive in a liberalised market as a guide to decision making. Transparency on price components is important for promoting better regulation and more competition. Wholesale power and ancillary services costs are reduced over the longer run by the use of wholesale spot markets to guide both short term dispatch and long-term investment in fossil fuel power plants. Transmission and distribution charges are an important component of costs, even in the UK these are 20% of the industrial price (where generation costs are 33%) and incentive regulation of network charges can bring large improvements in both cost efficiency and network quality. In China, there is a need to understand and expand role of retailers by separating them fully from distribution. State Grid Company of China and China Southern Grid (SGCC and CSG) provincial retail should be fully legally unbundled from distribution and allowed to compete nationally for retail customers. Competition in generation and retail needs to be effectively overseen and

[69] See Newbery (2017).
[70] See Bohn et al. (1984).

regulated by both the regulator (the NEA) and the Anti-Monopoly authorities as pressure to consolidate the sector and undesirable price discrimination is likely.

In China, there is a need for a focus on the big picture (e.g. how much have aggregate prices/efficiency/profits changed) rather than *just* the detail (e.g. zonal vs nodal pricing, central vs self-dispatch). The aim should be to stop the power sector being subject to purchasing requirements for domestic technology and domestic natural resources (in GB the electricity industry eventually escaped from its historic commitment to buying expensive British coal). In China, local taxation and non-externality related charges can distort production choices and impose unnecessary industrial policy costs on other industrial electricity customers. Instead the power sector's key role should be understood to be in promoting development in the wider economy by efficient (and fully cost reflective) pricing. It is important to produce electricity efficiently and use taxation to drive up the price to promote energy efficiency and decarbonisation, rather than letting incumbents justify high prices on grounds of energy efficiency.

Challenges remain for all countries, including China, in the future development of the power sector, with the rise of new distributed energy technologies. The current electricity system is characterized by high fixed costs which should be recovered. It is difficult to prevent behind the meter investments to avoid paying towards these fixed costs. This suggests there may be a need to lift some electricity system costs to general taxation (e.g. energy R+D, energy efficiency measures). In China, as the growth in the number of kWhs distributed slows attention to fixed costs will increase. More competition and better network regulation will lower profit margins at home, to the benefit of consumers and the discouragement of wasteful investment abroad and it will reduce concerns about private/foreign ownership in the electricity sector, as has happened in the UK.

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Additional Useful Resources on UK Electricity Reform

Oral History of Electricity Privatisation: British Library archive of key players:

This online archive is extensive with many recordings from different players…some are shown below:

- Cecil Parkinson – Secretary of State for Energy

– http://sounds.bl.uk/Oral-history/Industry-water-steel-and-energy/021M-C1495X0021XX-0001V0

- John Wakeham – Secretary of State of Energy

– http://sounds.bl.uk/Oral-history/Industry-water-steel-and-energy/021M-C1495X0048XX-0001V0

- William Rickett – Civil Servant involved with privatisation

http://sounds.bl.uk/Oral-history/Industry-water-steel-and-energy/021M-C1495X0033XX-0004V0

- Brian Pomeroy – Advisor on Electricity Privatisation

– http://sounds.bl.uk/Oral-history/Industry-water-steel-and-energy/021M-C1495X0048XX-0001V0

- Fiona Woolf – Advisor on Electricity Privatisation

– http://sounds.bl.uk/Oral-history/Industry-water-steel-and-energy/021M-C1495X0047XX-0001V0