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Strengths and Weaknesses of the British Market Model

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The British model has evolved to cover the island of Great Britain (England, Wales and Scotland), while Northern Ireland has evolved into a quite different market model covering the island of Ireland in its Single Electricity Market (SEM). This chapter discusses the British market. The main emphasis here is on England and Wales, which experienced the main restructuring. Scotland had two vertically integrated regional state-owned utilities which retained their unbundled structure after privatization.

Before restructuring and privatization in 1989-90, the state-owned Central Electricity Generating Board (CEGB) owned generation and transmission in England and Wales. Transmission and site location of new generation was coordinated by the CEGB, although the main high tension (440kV) grid had been largely completed by the 1960s with substantial spare capacity. Similarly, the intense period of building large power stations was predicated on continued growth in demand of 8% p.a. that had come to an abrupt halt with the first oil shock. The stations under construction would deliver substantial excess capacity once completed. Distribution and supply (retailing) were managed by 12 Area Boards, who paid the CEGB the Bulk Supply Tariff, an efficient multi-part capacity and energy charge with useful lessons for the future electricity system with high volumes of low marginal cost generation.

The CEGB's performance had been strongly criticized for its inefficiency, particularly in delivering timely and cost-effective investment, and under-pricing its output. After the success and lessons learned from earlier utility privatizations, the CEGB was ripe for restructuring to create competitive wholesale and retail markets, and regulated transmission and distribution networks. It had adequate generation and transmission capacity so needed little investment, used high cost domestic coal that was rapidly displaced by gas and imported coal, while RPI-X incentive regulation had matured and was well suited to regulating distribution companies that could be benchmarked against each other. Transmission regulation gradually improved with incentives, and both networks invested and also improved their quality of service.

Market power was a continuing problem for the wholesale market until the duopolists divested to create a workable competitive structure, just before the regulator and government, despairing of reforming the Pool and concerned with market power, replaced the centrally dispatched Pool model with capacity payments by an energy-only market and a two-priced Balancing Mechanism.

Vertical integration of generation and supply discouraged entry, unstable energy policies discouraged increasingly needed investment to replace aging fossil and nuclear plant, while the shift to the costly Renewables Obligation failed to deliver the renewables target.
Electricity Market Reform reintroduced capacity payments set at annual auctions. It replaced Renewable Obligation Certificates with a variant of Feed-in Tariffs, which, after auctions were introduced, lowered costs and made the UK the second largest EU producer of new renewables. Under pressure from the *Climate Change Act,* the 2011 Budget introduced the Carbon Price Support (CPS), a tax on the carbon content of fuels used to generate electricity.
The combination of the CPS, falling demand and growing renewables had a dramatic impact on the coal share, which fell from 41% in 2013 to 8% in 2018. The capacity auctions delivered new generation at 40% of the anticipated price, largely because of a distortionary subsidy provided to small distribution-connected generation. It took over three years for the regulator to remove that distortion. Just as the capacity auctions appeared to be bedding down as an efficient and credible way of procuring the right kind of capacity to deliver reliability and flexibility, in November 2018 the EU's General Court annulled the earlier EC decision to approve the GB Capacity Market, forcing the Government to suspend capacity payments and the December 2018 auction.
The British privatised electricity system is now 30 years old and a good moment to take stock of its successes and weaknesses. The premise of privatization was that private owners would invest and operate more efficiently than state-owned enterprises, and that by escaping the dead hand of the Treasury they could access more investment funds, would choose more cost-effective investments, and would cease unprofitable activities sooner and respond to new opportunities more quickly. These potential benefits would have to be weighed against the increased cost of private capital, and a possible loss of concern over distributional issues and environmental impacts, unless motivated to take them into account.
Avner Offer argues that the private sector is well placed to invest where the credit time horizon is attractive to private lenders, defined as the time to pay back the loan. Roughly speaking, private finance is twice the cost of public finance, so the private pay-back period (simply computed) is half that of the government. Government guarantees or their regulatory equivalent (such as the US model of rate-of-return regulation underpinned by a Constitutionally backed rule of law) can offer reassurances, lower the cost of capital and extend this credit horizon. The British electricity supply industry in 1989 was well placed to reap many of the benefits of private ownership, and initially, to avoid many of the downside costs. Spare capacity avoided the need for costly durable generating capacity and the risk of an inappropriate credit time horizon. The arrival of cheap CCGTs of modest scale, rapid delivery and high efficiency, at a time of falling gas prices, made any such investments lower risk. Even then, such investments needed long-term PPA contracts and a captive franchise market. The more capital-intensive and durable networks were assured of financeability through licence conditions, obligations on the regulator and a credible dispute resolution process. Distributional concerns emerged, and were, with varying degrees of success, met with licence conditions on utilities, Competition and Market Authority inquiries and price caps. Environmental concerns were met with increasingly stringent emissions standards on pollutants, the ETS, various EU Directives, and the Carbon Price Support.
Problems emerged when new capital-intensive generation investment was needed to meet carbon and renewables targets and to maintain reliability. The ideology of the market initially

led to auctions for renewables that were remarkably effective at driving down costs, less so at delivering adequate volumes. The shift to the Renewables Obligation pulled through more delivery but at a high cost of finance. It took over 20 years to learn from experience elsewhere that long-term contracts at assured off-take prices would lower the cost of capital and with it the delivered cost of renewable electricity.

Nuclear Power and Carbon Capture and Storage (CCS) demonstrated the force of Offer's credit time horizon. No nuclear power station has ever been constructed without strong and credible underwriting from either the government or a utility empowered to pass the cost through to final consumers. In Britain, Hinkley Point C has staggered on since before privatization, and only (just) secured its Final Investment Decision after one of the most costly financing arrangements with government guarantees. Given a possible construction period of ten years and a subsequent life of 60 years, followed by possibly centuries of waste management, nuclear power busts Offer's credit time horizon comprehensively. CCS has had an even worse experience, with over a decade of unfulfilled promises to deliver a commercial-scale plant. Even conventional CCGTs now need 15-year capacity payments to encourage investment, so that to a greater or lesser extent all new generation now receives under-written guarantees by the Government.

Critics argue that this reflects a betrayal of the original aims of privatization, while realists (and very belatedly and to a limited extent, the Government) argue that durable essential infrastructure like electricity needs access to low-cost finance that only government-backed or guaranteed finance can assure. Perhaps the most useful lesson from privatizing utilities is that the UK has evolved a system of regulating at least part of the infrastructure (the natural monopoly pipes and wires) that works reasonably well and has delivered high levels of investment at modest rates of interest. It would be encouraging to think that the UK can continue to learn how better to finance the necessary capital-intensive zero carbon energy to meet our climate goals in a timely fashion.

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