Reforming Australia's electricity market

Lessons for the UK

Ed Birkett

Reforming Australia's electricity market

Lessons for the UK

Ed Birkett

About the Author

Ed Birkett, Head of Energy and Environment at Policy Exchange
Ed Birkett leads Policy Exchange's Energy and Environment Unit. Ed joined Policy Exchange in 2020 after spending a year at Harvard as a Kennedy Scholar. For the previous five years, he worked in the UK energy sector, most recently as a developer of large-scale solar and energy storage projects. He has an MEng in Engineering Science from the University of Oxford.

Acknowledgements

The author would like to thank the experts from Australia and the UK who provided input to this report. The author would also like to thank Josh Buckland and James Allan for reviewing a draft of this report.

This report was produced by Policy Exchange and the views and recommendations in the report are those of Policy Exchange.

Published by
Policy Exchange, 8 – 10 Great George Street, Westminster, London SW1P 3AE

www.policyexchange.org.uk

ISBN: 978-1-913459-80-2

Contents

Recommendation:

Building on the success of the "Offshore Transmission Network Review" (OTNR), the Government should set up a "Wholesale Electricity Market Review" (WEMR) to coordinate reforms to Great Britain's wholesale electricity market.

1: Introduction

In the run up to the COP26 climate conference, the Australian Government made a new commitment to achieve Net Zero emissions by 2050; gaining Net Zero commitments was a high priority for the UK's COP Presidency team, led by Rt Hon Alok Sharma MP.[1]

Despite this, many international observers were left disappointed by the country's relative lack of new policies to reduce emissions in the short term. In particular, Australia has not updated its 2030 emissions target, which was originally set in 2015.[2]

However, Australia is making substantial progress in some areas, in particular cleaning up its electricity sector. In October, Ministers approved reforms to the country's electricity market, which will be developed further and implemented from 2025 onwards.[3] These reforms will help to integrate more wind and solar farms, including through greater use of local electricity pricing, something that Policy Exchange has argued for in the UK.[4]

Great Britain's electricity market faces similar challenges to Australia's and also urgently needs reforming. The Australian reforms offer a model for the UK; however, Australia is only partially implementating of local pricing. In addition, the Australian reforms look like they will be overly generous to existing generators, which will likely result in higher customer bills compared to a fully-reformed market.

Even after the reforms, the Australian market is unlikely to be ready for a Net Zero electricity system. This means that further changes are likely to be required in the future, for example fully-implementing local electricity pricing; this creates uncertainty for market participants.[5] The UK should therefore go further than Australia, and move directly to an electricity market based on local pricing. This will ensure that Great Britain's electricity market is ready to deliver Net Zero as cheaply as possible.

Recommendation: Building on the success of the "Offshore Transmission Network Review" (OTNR), the Government should set up a "Wholesale Electricity Market Review" (WEMR) to coordinate reforms to Great Britain's wholesale electricity market.

1. Australian Government: Department of Industry, Science, Energy and Resources (October 2021). *Australia's Long-Term Emissions Reduction Plan.* Link
2. Australian Government: Department of Industry, Science, Energy and Resources (undated). *International climate change commitments.* Link
3. Australian Government: Department of Industry, Science, Energy and Resources (October 2021). *Post-2025 market design.* Link. These reforms apply to the National Electricity Market (NEM), which covers 90% of the market (QLD, NSW, ACT, VIC, TAS, and SA).
4. Policy Exchange (December 2020). *Powering Net Zero.* Link
5. The ESB's advice is clear that it continues to believeb that full nodal pricing ("LMP/FTR") would be a more cost-effective long-term solution. See: Energy Security Board (July 2021). *Post-2025 Market Design: Final advice to Energy Ministers: Part B.* Link. Page 114. *"To provide stability and clarity to the market, the ESB's view is that implementing the CMM(REZ) should be the priority reform at the current time to address congestion. While it does not form part of the ESB's recommendations, the ESB continues to hold the view that the full LMP/FTR model could be a long-term solution given that it is used successfully in many jurisdictions. This market design is in long term interests of customers because it is the most realistic representation of what is happening on the physical power system, as well as being internationally accepted as best practice."*

2: Australian context

Following a regional blackout, the Australian Governments established review of their electricity market.

In 2016, the Australian Governments established an independent review of the National Electricity Market (NEM).[6] The review was established to address concerns about security of supply and reliability, which were heightened following a state-wide blackout in South Australia in September 2016 caused by high-intensity storms .[7]

Following the review, the Government created the independent Energy Security Board (ESB) to implement the recommendations.[8] This year, the ESB recommended major changes to Australia's electricity market as part of its *Post-2025 Market Design* project. In October, Ministers accepted most of these recommendations and asked to see further details on others.[9]

The *Post-2025 Market Design* project has several elements, including proposals for a national capacity mechanism similar to the UK's Capacity Market. The capacity mechanism will help to ensure that there is always enough capacity available to keep the lights on, even in periods with low generation from wind and solar farms.

This paper focuses on how "congestion" will be handled in Australia's reformed market, as this is the area that is most relevant to Great Britain.

Congestion occurs when the power lines between two regions are operating at maximum capacity. For example, in the UK, the power lines between Scotland and England are often congested when Scottish wind output is high.

Rising wind and solar means that the Australian electricity network is increasingly "congested".

Renewable energy in Australia is growing quickly, with solar and wind providing 18% of Australia's electricity in 2020, up from 7% in 2015.[10] However, the Australian market, like others, is now experiencing challenges. As more wind and solar farms are built, the electricity network is becoming increasingly "congested".

Under the current market rules, the costs of congestion are largely socialised, increasing energy bills. Without reform, these costs are likely to rise sharply as more wind and solar farms are built.

In addition, because the costs of congestion are socialised, market participants are not properly incentivised to solve the problem. For example, companies could reduce congestion by installing battery storage or by using electricity at different times of day.

In the British electricity market, the cost of congestion is expected to more than double during the 2020s, particularly as more offshore winds come online.[11]

6. The review was initiatd by the Coalition of Australian Governments (COAG) energy ministers. See: Energy Consumers Australia (October 2016). *Information Bulletin: COAG 67th Council Meeting: 7th October 2016.* Link
7. Australian . *Independent Review into the Future Security of the National Electricity Marke: Final Reportt.* Link. Page 43.
8. Energy Security Board (undated). *Who is the Energy Security Board?* Link
9. Australian Government: Department of Industry, Science, Energy and Resources (October 2021). *Summary of the final reform package and corresponding Energy Security Board recommendations.* Link. Ministers have asked to see more detail on how the proposed capacity mechanism and Congestion Management Model could work in practice.
10. Australian Government: Department of Industry, Science, Energy and Resources (June 2021). *Australian Energy Statistics, Table O Electricity generation by fuel type 2019-20 and 2020.* Link
11. National Grid ESO (undated). *Modelled Constraint Costs: NOA 2020/21.* Link. Page 2: "the NOA6 analysis shows modelled constraint costs increasing significantly this decade - from c. £0.5bn/year today to between £1bn and £2.5bn/year at a maximum before they then reduce again at the end of the decade when new major transmission investments come online,"

3: Australian proposals

Australia has proposed a bespoke form of local electricity pricing, but with a major carveout for incumbents.

To address congestion, the Australian Energy Security Board (ESB) recommended a new "Congestion Management Model" that includes elements of local electricity pricing.[12]

Under the new rules, generators will continue to receive a regional electricity price under normal conditions.[13] However, when a region is constrained, generators in that region will receive a mix of a local price and a regional price.[14]

Under local pricing, prices will rise and fall in different places depending on local supply and demand for electricity. For example, at times of high solar generation, wholesale electricity prices will fall in areas with lots of solar farms; this will particularly affect regions with fewer transmission lines to carry power to customers in other regions.

The ESB argues that introducing an element of local pricing will encourage market participants to manage grid congestion, for example by building batteries and other types of storage.[15] Because local pricing more accurately reflects underlying supply and demand, it is more economically efficient and should reduce energy bills overall.

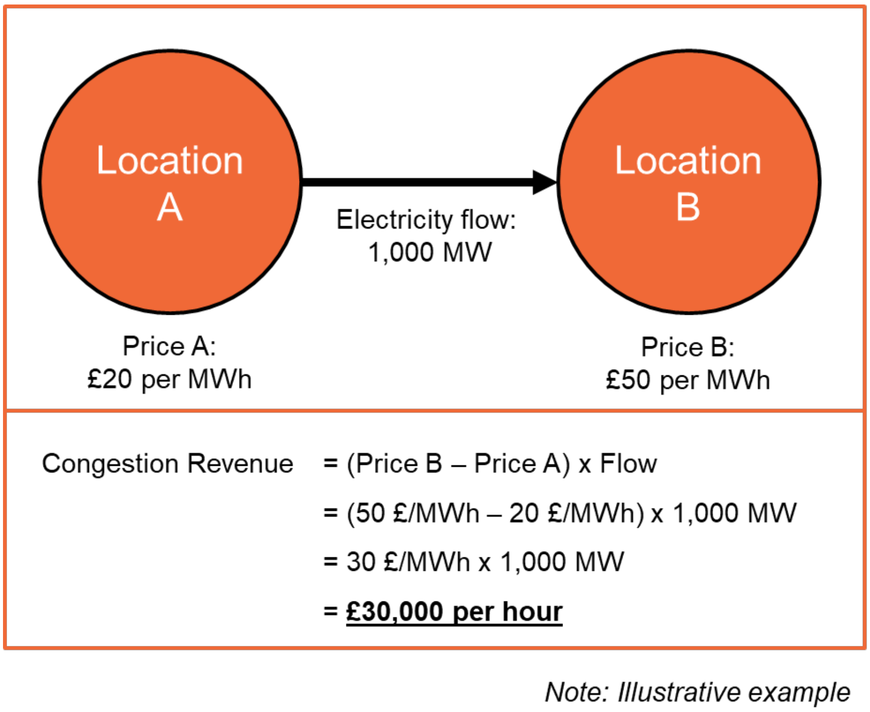
A similar logic applies in the UK. Last year, Policy Exchange commissioned Aurora Energy Research to analyse whether local electricity pricing could reduce energy bills. Aurora found that splitting Great Britain's market into three regional price "zones" could reduce bills by £2bn per year.[16] Further benefits could be unlocked by splitting Great Britiain into hundreds or thousands of local pricing "nodes". The Australian model would effectively create hundreds or thousands of local pricing nodes, but the reforms are not described as such.

Local pricing creates a new revenue stream for the market operator: "Congestion revenue".

Under local pricing, prices in neighbouring regions are different when the power lines linking the two regions are operating at maximum capacity. When this happens, the market operator collects additional revenue known as "congestion revenue" (see Figure 1). Congestion revenue is the difference between the price paid to generators in the exporting region (Location A) and the price paid by customers in the importing region (Location B).

12. In the documents, "local electricity pricing" is referred to as "Locational Marginal Pricing" or "LMP". Australia currently uses "regional pricing", also known as "zonal pricing".
13. Australia's National Electricity Market currently has 5 regional pricing zones (SA, TAS, VIC, NSW, QLD).
14. The exact details depend on the exact rules of the bespoke Congestion Management Model, which are yet to be finalised. Some generators will exclusively receive a local price, whereas others could predominantly receive a regional price. This is discussed in more detail later in this report.
15. Energy Security Board (July 2021). *Post-2025 Market Design: Final advice to Energy Ministers. Part B*. Link. Page 109.
16. Policy Exchange (December 2020). *Powering Net Zero*. Link. See *Appendix 1: Aurora Energy Research*. Link

Figure 1: Illustrative example of congestion revenue.



In most markets with local pricing, congestion revenue is used to reduce customer bills. For example, in Scandinavia, which has 12 price zones, congestion revenue pays some of the cost of building and maintaining the regional electricity network.[17] Without congestion revenue, these network costs would be recovered from customers through higher bills.[18,19]

The Australian model will give congestion revenue to generators, not customers.

Under the Australian proposals, congestion revenue will be rebated to some generators to compensate them for local variations in electricity prices. Generators in areas with very low local prices will receive the biggest rebates.

The proposed rebates will go to all existing generators and to all new renewable energy generators that are built in the "right" places, as defined by the system operator and the Government. The exact rules are still under development.

For existing generators, the rebates are designed to mitigate the impact of the new rules on profitability. The ESB argues that, because existing generators have already decided where to locate, the rebates are justified to help "replicate existing profitability".[20] This reduces the risk that some coal- and gas-fired power stations would close suddenly once the new rules are in place; any sudden closures of power plants could put Australia's security of supply at risk.

This argument is understandable as a transitional measure to reduce market disruption. However, if this arrangement continues in the long term (as currently proposed), then it will reduce the economic efficiency

17. Norway (5 zones), Sweden (4 zones), Finland (1 zone) and Denmark (2 zones). See: Nord Pool (undated). *Bidding areas.* Link

18. Fingrid (undated). *Congestion income.* Link.

19. The EU has recently passed rules on how congestion revenue can be used by TSO. See: ACER (January 2021). *ACER decides methodology for Use of Congestion Income when allocating cross-border capacity.* Link

20. Energy Security Board (July 2021). *Post-2025 Market Design: Final advice to Energy Ministers. Part B.* Link. Page 109.

of Australia's electricity market, raising energy bills.

For new renewable energy generators, rebates will be paid to new wind and solar farms that are built in designated "Renewable Energy Zones" (REZs). These zones will benefit from new transmission lines that will connect them to customers in urban areas.

The ESB argues that wind and solar projects connecting in these zones should benefit from rebates because they are connecting in the "right" places, from a network development point of view.[21] Because the rebates will partially insulate them from changes in local electricity prices, these renewable energy projects will get more certainty over their future revenue.[22] This will help project developers to finance new projects, speeding up decarbonisation.

There are good reasons to implement Renewable Energy Zones, which have been used successfully in markets such as Texas.[23] Policy Exchange has previously argued that REZs could be used as part of the UK's planned offshore electricity network, which will connect offshore wind farms to customers onshore.[24]

However, it is concerning that the Australian proposals combine Renewable Energy Zones with preferential access to rebates; this requires the Government or the market operator to designate the "right" places for generators to connect (the REZs), and to disadvantage those that connect elsewhere.

The Australia proposals therefore risk politicising the designation of Renewable Energy Zones, as projects in those areas will receive preferential treatment (rebates). [25]

21. If new generators locate in the "right" places, fewer new power lines will need to be built, saving money.
22. Note that the proposals **do not** give developers a long-term fixed-price contract (such as a UK CfD). The proposals mean that new generators in Renewable Energy Zones continue to receive a regional/zonal wholesale price (as today). It appears that there could be some situations where the revenue received by individual generators deviates from the regional/zonal price; however, this depends on the final rules for how the rebates are allocated. See: Energy Security Board (July 2021). *Post-2025 Market Design: Final advice to Energy Ministers. Part C – Appendix.* Link. Pages 50-51.
23. NREL (2016). *Renewable Energy Zones: Delivering clean power to meet demand.* Link
24. Policy Exchange (July 2021). *Crossed Wires.* Page 49. Link
25. Responsibility for identifying and developing Renewable Energy Zones sits with a combination of the Australian Energy Market Operator (AEMO) and the State Governments. See: AEMO (June 2020). *Integrated System Plan (ISP) update: Renewable Energy Zones.* Link. See: NSW Government (undated). *Renewable Energy Zones.* Link

4: Lessons for the UK

Congestion is also a big problem in Great Britain's electricity market.

Great Britain's electricity market is decarbonising rapidly, with emissions falling two-thirds since 2010.[26] The main factor driving these emission reductions is the rapid phase-out of coal-fired power stations and the rapid take-up of wind and solar.

However, rising wind and solar production in the UK is causing more network congestion, similar to the Australian experience. Great Britain's electricity system operator, *National Grid ESO*, forecasts that "constraint costs" will rise from around £500m this year to between £1bn and £2bn per year during the 2020s.[27] To reduce constraint costs, the electricity system operator recommends investing up to £16bn in new power lines and substations over the next decade or so.[28]

Therefore, although the UK and Australia have very different wind and solar resources, both markets are facing similar problems with network congestion.[29]

The UK can go further than the Australian reforms because it has robust policies to support new renewables.

Australia's "Congestion Management Model" is a big step forward. However, the proposed rebates to generators risk diluting the benefits of local pricing, which risks raising bills.

One reason why the Australian proposals include rebates is that, without rebates, new renewable energy generators could face very volatile local wholesale electricity prices. This would make it more difficult to finance new projects. In the absence of other major policies to encourage new renewable energy generators, the Australian proposals are an understandable compromise.[30]

However, the UK context is completely different.

The UK has robust carbon pricing, which increases revenues for renewable energy projects. In addition, the UK Government runs auctions for renewable energy projects every two years. These auctions offer renewable energy projects a fixed electricity price for 15 years, which helps projects to attract cheap finance; these contracts are known as "Contracts for Difference" (CfDs).[31]

Because the UK has policies to support renewable energy projects, introducing local pricing is unlikely to slow deployment. If it does, then the Government can mitigate this by increasing its procurement targets in subsequent CfD auctions. This means that the UK Government can go for a "full-fat" reform of its electricity sector, implement local pricing and resist calls for rebates to generators.[32]

26. Climate Change Committee (June 2021). *Progress in reducing emissions: 2021 Report to Parliament*. Link. Page 62.
27. National Grid ESO (date unknown). *Modelled Constraint Costs: NOA 2020/21*. Link. Page 2: "the NOA6 analysis shows modelled constraint costs increasing significantly this decade - from c. £0.5bn/year today to between £1bn and £2.5bn/year at a maximum before they then reduce again at the end of the decade when new major transmission investments come online,"
28. Ibid. Page 2. "The NOA 2020/21 (NOA6) highlights that there is a need for up bto £16bn of transmission investment over the coming years."
29. The Australian electricity system is expected to rely heavily on solar farms and onshore wind farms, whereas the UK is expected to rely more heavily on offshore wind farms.
30. For example, there is no Federal carbon price in Australia. The Australian Federal Government does have a Renewable Energy Target (RET); however, this 2030 target has already been exceeded, so the policy does little to incentivise investment in additional renewable energy projects (Link, Link). Individual states and territories have their own renewable energy targets and policies.
31. BEIS (October 2019). *Contracts for Difference (CfD) Allocation Round 3: results*. Link
32. Similar arguments apply for new nuclear power stations in the UK, which are expected to receive price support either through a CfD or a Regulated Asset Base (RAB).

UK Ministers should lead the market reform process.

To progress reform in the UK, the Government should undertake a comprehensive review of Great Britain's wholesale electricity market. Importantly, this review should be led by the Government, through BEIS, rather than by the regulator (Ofgem) or the electricity system operator (National Grid ESO). Any decision to implement local pricing would create winners and losers. This trade-off is inherently political, so Ministers need to be running the process and making the final call.

The Australian proposals are a half-way house, implementing a bespoke form of local electricity pricing but largely insulating most generators from its impacts; whilst understandable in the Australian context, this would be the wrong outcome for the UK.

Policy Exchange has already set out how we think the market should be reformed; see our 2020 report, *Powering Net Zero*.[33] We believe that local electricity pricing is the key to delivering a Net Zero energy system that is both affordable and secure. Wider reforms are also needed, including merging the Contracts for Difference scheme and the Capacity Market into a single scheme, so that "firm low-carbon resources" are properly rewarded for the value they provide.[34]

The regulator, Ofgem, and the electricity system operator, National Grid ESO, are both already working on possible market reforms.

Earlier this year, National Grid ESO kicked off a project on "Net Zero Market Reform".[35] This project is due to recommend a "preferred high-level package of reforms" to Great Britain's electricity market by April 2022.

Separately, earlier this month, Ofgem issued a tender for an external consultant to model "design options for nodal pricing in Great Britain".[36] The project will analyse how nodal/local pricing could be implemented in Great Britain, including the cost, benefits, and distributional impacts of local pricing. This project is expected to conclude in June 2022.

Once these two projects are complete, work will turn to a detailed evaluation of policy options; this evaluation will involve political trade offs. Because of the political nature of these decisions, Ministers (through BEIS) should take charge of the process.

When developing detailed proposals, BEIS should involve Ofgem, the ESO, and other stakeholders. This would mirror the approach taken throughout the "Offshore Transmission Network Review" (OTNR), which is widely viewed as a successful model.[37]

Recommendation: Building on the success of the "Offshore Transmission Network Review" (OTNR), the Government should set up a "Wholesale Electricity Market Review" (WEMR) to coordinate reforms to Great Britain's wholesale electricity market.

33. Policy Exchange (December 2020). *Powering Net Zero*. Link
34. "Firm low-carbon resources" include nuclear, biomass, geothermal, and long-duration battery storage, amongst others.
35. National Grid ESO (undated). *Net Zero Market Reform*. Link
36. Bidstats (December 2021). *A Tender Notice by OFGEM: Design Options for nodal pricing in GB*. Link
37. Gov.uk (undated). *Offshore transmission network review*. Link

Policy Exchange

£10.00
ISBN: 978-1-913459-80-2

Policy Exchange
8 – 10 Great George Street
Westminster
London SW1P 3AE

www.policyexchange.org.uk