Unclassified **DAF/COMP/WP2/WD(2017)1**

Organisation for Economic Co-operation and Development

31 May 2017

English - Or. English

DIRECTORATE FOR FINANCIAL AND ENTERPRISE AFFAIRS
COMPETITION COMMITTEE

Working Party No. 2 on Competition and Regulation

The Transformation of the Electricity Sector in Australia: The Public Policy and Competition Policy Issues

Paper by Dr Darryl Biggar

19 June 2017

This document reproduces a written contribution produced by Dr Darryl Biggar, a Special Economic Advisor at the Australian Competition and Consumer Commission (ACCC) and the Australian Energy Regulator (AER). The views expressed in this paper are the views of the author and not the views of the ACCC or the AER. This paper is submitted for Item 3 of the 63rd meeting of the OECD Working Party No. 2 on Competition and Regulation on 19 June 2017.

More documents related to this discussion can be found at www.oecd.org/daf/competition/radical-innovation-in-the-electricity-sector.htm

Please contact Mr. Chris Pike if you have any questions regarding this document [phone number: +33 1 45 24 89 73 -- E-mail address: chris.pike@oecd.org].

JT03414984

The transformation of the electricity sector in Australia: The public policy and competition policy issues

Dr Darryl Biggar[*]

1. Introduction

1. The electricity industry in Australia – as in many other countries around the world – is undergoing a fundamental transformation that has been described as potentially the most profound change to the energy industry since the sector was created.[1] This transformation is due to a number of factors which have been well documented[2] and has sparked an unprecedented number of policy reviews and inquiries[3]. The primary drivers of the transformation are:

- Technological change which is rapidly lowering the cost and improving the efficiency of renewable generation sources, particularly solar PV, and battery storage;
- The development of smart devices, thermostats, and appliances which are capable of responding to changing electricity market conditions, and the metering and communications infrastructure to control those devices;
- Policies to decarbonise the electricity sector through a move to low carbon emitting generating technologies, renewable generation mandates, subsidies for solar PV, and building codes and mandated efficiency standards.[4]

2. This paper has been prepared for an OECD hearing on radical innovation in the electricity sector. The issues paper for that hearing raised four broad topics for discussion: (i) peer-to-peer electricity markets; (ii) electricity or multi-utility service companies; (iii) collective buying/aggregation schemes; (iv) super-grids.

---

[*] Dr Darryl Biggar is a Special Economic Advisor at the Australian Competition and Consumer Commission (ACCC) and the Australian Energy Regulator (AER). The views expressed in this paper are the views of the author and are not the views of the ACCC or the AER.

[1] Commerce Commission of New Zealand (2016), page 15. John Bradley, Energy Networks Australia, speech on 4 October 2016: "Australia's energy system is undergoing the most radical transformation since the days of Edison and the original Tesla.". AEMC (2017).

[2] See, for example, Commerce Commission of New Zealand (2016), Energy Transitions Commission (2017), MIT EI (2016), Productivity Commission (2013).

[3] See, for example, the Finkel Review (the "Independent Review in the Future Security of the National Electricity Market"), the House of Representatives Select Committee on the Environment and Energy Inquiry into Modernising Australia's electricity grid, the AEMC's System Security Market Frameworks Review, and the South Australian Legislative Council's Select Committee on the State-wide Electricity Blackout and Subsequent Power Outages.

[4] Such as the objective in California that all new residential construction be Zero Net Energy by 2020. In addition to these technological developments there is an associated changing attitude or expectation amongst electricity consumers that they should have a degree of choice and control over their production and consumption of electricity.

3. This paper takes the approach that innovation in the electricity sector is only a problem to the extent that the policy settings are imperfect or inadequate. With a good, resilient, and flexible policy framework, all innovation – no matter how radical – could in principle be accommodated and encouraged. At the same time, if the policy framework is imperfect, innovation will be a threat to the regime.

4. Australia has a good policy foundation for the electricity sector, but there is much further to go. The existing framework is coming under increasing pressure from the technological developments mentioned above. This paper looks at the policy changes that may be necessary to accommodate the transformation of the electricity industry. Some of those policy changes are minor, but some are more substantial. Radical innovation in the electricity sector may demand a radical policy response.

5. This paper has four sections. The next section briefly describes the structure and operation of the electricity market on the east coast of Australia. Section 3 sets out a list of the public policy issues arising from the transformation of the electricity sector with a brief commentary on each. Section 4 concludes.

2. A brief overview of the electricity sector in Australia

6. This paper focuses on the interconnected electricity system which operates on the east coast of Australia, covering the states of Queensland, New South Wales, Victoria, Tasmania, and South Australia. West Australia and the Northern Territory have their own isolated electricity networks which operate under slightly different rules. In addition there are many isolated electric power systems in remote parts of Australia.

7. When describing the electricity sector on the east coast of Australia, we can divide the subject into four broad areas: The wholesale market and wholesale market participants; the networks and associated regulatory infrastructure; the retail market and the customer-facing aspects; and the regulatory institutions and governance arrangements. The following paragraphs briefly describe each of these areas in turn.

2.1. The wholesale electricity market

8. The wholesale electricity system on the east coast of Australia is focused around an energy-only gross pool market known as the National Electricity Market or NEM.[5] This market is operated by the Australian Energy Market Operator or AEMO. Every five minutes AEMO solicits bids and offers from all wholesale electricity market participants, and collects information on the level of demand and the current state of the transmission network. AEMO then carries out a conventional bid-based security-constrained economic dispatch, resulting in five-minute dispatch targets[6] for all wholesale market participants, together with corresponding wholesale spot prices at which participants are settled.[7]

[5] See the Wikipedia entry for the National Electricity Market, or the descriptions provided by the Australian Energy Markets Commission, the Australian Energy Market Operator, the State of the Energy Market publication of the Australian Energy Regulator or AEMO (2010).

[6] A dispatch target specifies how much each participant is to produce or consume over the next five minute interval.

[7] Currently market participants are settled at 30-minute “trading prices” which reflect the simple average of six consecutive “dispatch prices”. However there is a Rule Change currently under consideration to change the settlement to the five-minute dispatch prices. See AEMC, “Rule Change: Five Minute Settlement”.

9. Many liberalised wholesale electricity markets around the world determine separate spot electricity prices at a large number of separate geographic locations. This is known as locational marginal pricing or nodal pricing. The Australian NEM does not use nodal pricing. Instead, it uses a form of “regional” pricing. All market participants within a region are settled at the regional reference price (the price at a designated reference node) rather than the local nodal price. The resulting mis-match between pricing and dispatch gives rise – at the rare times when transmission constraints within a region are binding – to a phenomenon known as “disorderly bidding”.

10. At present there are five regions in the NEM, corresponding to the five member states. The four mainland states are connected via a synchronous AC transmission network.[8] Tasmania is connected to the mainland through an undersea DC cable. There is one reference price determined in each region (i.e., one for each state). There is a wholesale spot price floor of $-1000/MWh and a price ceiling of approximately $14,000/MWh.

11. In addition to the five-minute spot market for energy, there are a number of associated markets. The most important of these are markets for the provision of contingent energy over a short time-frame. These services are used to maintain a balance between supply and demand during the five-minute interval until the operation of the next dispatch cycle. Since the supply-demand balance affects the system frequency, these markets are known as frequency-control ancillary services markets. At present there are seven such markets (corresponding to different time intervals over which the required contingent energy must be supplied, and whether the services is used to raise or lower the system frequency).

12. The participants in the wholesale electricity market are primarily large generating companies. These large generating companies are mostly privately owned, representing a range of energy interests from around Australia and around the world (including China). A few generating companies remain within state ownership. However, the government has no direct role in generation entry/exit, or operation decisions.

13. Historically, the primary energy source was coal (black and brown). In recent years a number of coal-fired power stations have retired, reducing reliance on coal-fired generation slightly. There is also a substantial amount of gas-fired, and hydro-electric generation. Due to a sizeable renewable energy mandate (the RET scheme[9]) wind and solar make an increasing contribution, especially in South Australia where, at times, the total amount of wind generation has exceeded local (in state) demand.

14. On the whole there has been adequate competition in the wholesale electricity market. On a typical day transmission constraints across the regions are not binding, allowing electricity to be traded freely across the entire NEM. At such times, even the largest generators in the NEM have a very small market share and very limited market power. However, on peak days transmission constraints are occasionally binding, especially into the “edge-of-NEM” states – South Australia, Queensland, and Tasmania. At such times, local generation can occasionally have substantial market power. The increasing penetration of wind generation has led to the retirement of some conventional

[8] There are also two HVDC links – between SA and VIC, and between NSW and QLD. These HVDC links operate in parallel to the conventional AC network.

[9] See http://www.cleanenergyregulator.gov.au/RET

thermal generation, resulting in higher levels of concentration amongst producers at times when the wind is not blowing.

15. In recent months the opening of major LNG export trains[10] in Queensland has substantially increased the local demand for natural gas, increasing the local natural gas price to a level of export parity corresponding to the world price for LNG. This has led to a very substantial increase in the variable cost of gas-fired generation, resulting in a substantial increase in the forward price for electricity.

2.2. The regulated networks

16. Electrical energy is transported to customers over the monopoly transmission and distribution networks. There are five transmission businesses (one in each state) and thirteen distribution businesses.

17. The regulatory framework for these network businesses operates on a rotating five-year regulatory period. The regulatory framework is incentive-based, employing a revenue cap, determined using what is known in Australia as the “building block model”. There are various incentive mechanisms which provide incentives for service quality (reliability) and incentives to make expenditure savings over time.

18. In regards to network pricing, at the transmission network level the wholesale market mechanism (discussed above) provides some limited dynamic locational price signals for pricing across regions. The resulting differential prices provides a (limited) stream of revenue to the market operator which is allocated back to network businesses. The remaining costs for the provision of transmission network services are recovered from load customers using a form of cost allocation. Generators do not pay transmission charges (although they may incur costs establishing a connection to the nearest point on the shared transmission network).

19. Historically distribution network charges have not been cost reflective. Although some larger distribution customers paid charges based on peak consumption (so-called demand-based charges), historically due to the lack of metering capability all smaller customers paid simple time-averaged charges, such as inclining-block charges or declining-block charges. A recent change in the regulatory framework requires distribution network charges to be cost-reflective. Distribution networks are now required to publish a statement of how their tariffs will be structured in advance of each five-year regulatory period. Due to a lack of advanced metering, and political concerns about the rate of change, the degree of movement towards cost reflective tariffs has been limited to date (this is discussed further below).

2.3. The retail market

20. Very few (if any) loads directly participate in the wholesale spot market. Instead, almost all loads purchase electricity services through an electricity retailer. All customers in the NEM are free to select a retailer of their choosing. The role of the retailer is to interface between the volatile wholesale market and the end-customer energy-services contracts that end-customers desire. This is primarily a billing and risk-management role. A few states retain price controls on the default or “standing” tariff. Otherwise, retailers are free to set their prices as they wish.

[10] An LNG train is a facility for converting natural gas into its liquid form.

21. There have been some concerns that end-customers find it difficult to compare retail offers. Retail offers consist of at least two parts (fixed and variable) and usually contain many different components, such as sign-on bonuses and conditional discounts. These contracts are likely to become more complex in future as retailers offer to sell, lease and/or take control of smart devices and appliances, battery storage, or electric vehicle charging. There have been some attempts to allow end-customers to easily compare electricity tariffs, including comparison websites, such as EnergyMadeEasy or the Victorian Government Energy Compare.

22. There has been a degree of concern about persistently high retail margins in some states (particularly in Victoria which has the longest experience with full retail competition). This has recently led the federal government to request the ACCC to carry out a market inquiry into whether there is effective competition in the retail sector, discussed further below.[11]

2.4. The regulatory institutions and governance arrangements

23. In Australia, energy policy is a state rather than federal responsibility. The creation of the National Electricity Market required the establishment of institutions to facilitate co-operation between the states and to govern the sector. The peak government body with responsibility for the energy sector is known as the COAG (Council of Australian Governments) Energy Council.[12] The Energy Council consists of representatives from each state – usually the state energy Minister – together with representatives from the federal government.

24. The electricity sector is governed by legislation (the National Electricity Law) and a detailed set of regulations known as the National Electricity Rules. A dedicated body has been established to consider and advise on changes to the Rules, known as the Australian Energy Markets Commission (AEMC).[13] The AEMC also provides strategic advice and conducts inquiries at the request of the Energy Council.

25. Responsibility for setting the prices of the monopoly network businesses has been delegated to the Australian Energy Regulator (AER)[14], a constituent part of the Australian Competition and Consumer Commission (Australia's competition authority, ACCC). The AER also has responsibility for monitoring the operation of the wholesale market and for overseeing the obligations in the retail market. The AER publishes an annual State of the Energy Market report which sets out more detailed information on the electricity and gas sectors in Australia.[15]

3. Public policy issues and competition policy issues

26. The electricity sector on the east coast of Australia has proven successful and robust to major challenges over the last twenty years. The wholesale market design, coupled with regulated network services, and full retail competition, has provided robust

[11] See https://www.pm.gov.au/media/2017-03-27/accc-review-electricity-prices

[12] http://www.coagenergycouncil.gov.au/

[13] http://www.aemc.gov.au/

[14] https://www.aer.gov.au/

[15] The 2017 State of the Energy Market was published 30 May 2017.

and reliable service, has incentivised substantial new investment, has led to the orderly retirement of existing plant, and provides an important foundation for future reform. As noted above, Rule change mechanisms are in place to allow further iterative improvement over time.

27. But recent developments have raised many fundamental new public policy and competition policy issues. The concern by policymakers can be seen in the unprecedented number of major reviews into the electricity sector which have been initiated over the last twelve months.[16]

28. In my view, the major public policy and competition policy issues facing the electricity sector are as set out below:

3.1. Pricing of the distribution network

29. The first, and arguably most important, issue facing the electricity sector worldwide is the efficient pricing of distribution networks. Historically, distribution networks have been priced in a time-averaged manner which ignores local congestion. As a consequence, the distribution network has had to be sized to cater for all but the most exceptional peak loads, even if that means most of the capacity of the network is idle most of the time. It is said that more efficient pricing could result in higher network utilisation and lower overall costs by as much as 30%.[17]

30. In order to achieve efficient usage and investment decisions in the electricity sector, end-customers should pay a price for electricity which reflects the marginal cost of producing that electricity and delivering it to the location of the consumer. It will be very difficult to achieve efficient usage and investment decisions by end customers in a range of smart devices and appliances[18] if customers are not directly, or indirectly, exposed to the costs incurred by their decisions. As a group from MIT has said:

"The only way to put all resources on a level playing field and achieve efficient operation and planning in the power system is to dramatically improve prices and regulated charges (i.e., tariffs or rates) for electricity services".[19]

31. There are three main components of the price for electricity paid by the customer: (i) the wholesale cost of generating the electricity; (ii) the cost of transporting the electricity over the transmission network; (iii) the cost of transporting the electricity over the distribution network. There is an additional cost (the retail cost) which must be paid by end-customers who use the services of a retailer.

32. Of these costs, the existing wholesale electricity market in Australia does a tolerable job of pricing the wholesale energy and transmission network components. As noted above, as in other liberalised electricity markets, the wholesale energy market in

[16] See footnote 4.

[17] See, for example, ENA (2017): "If Networks buy grid services from DER Customers in the right place at the right time, this 'orchestration' could replace the need for $16.2 billion in network investment, avoid cross subsidies, and lower average network bills by around 30% compared to today."

[18] These devices and appliances (including local generation and battery storage) are collectively known as Distributed Energy Resources or DER.

[19] MIT EI (2016).

Australia prices energy and transmission services in a dynamic, time-varying manner which reflects the transmission constraints on the power system as they arise.[20]

33. The same cannot be said, however, for distribution pricing. Historically, due to a lack of metering infrastructure and a lack of controllable devices and appliances, distribution tariffs have not been dynamic, time-varying, locational, and reflective of the constraints on the distribution network as they arise.

34. Economic theory is clear that efficient tariffs should reflect the short-run marginal cost of providing services. In the case of distribution networks, the short-run marginal cost is reflected in differences in the price of energy at different locations on the network at different times. Those price differences should reflect both energy losses on the system and the cost of binding constraints on power flows on the distribution system – in the same manner as prices are currently determined at the transmission network level.

35. Efficient pricing of the distribution network would be a sizeable public policy challenge. In principle it would require the establishment of a market, along the lines of the bid-based security-constrained economic dispatch process which currently operates at the transmission network level.[21] This would almost certainly require the establishment of a distribution market operator. The roles of other market participants would have to change. In particular, retailers would likely have to take a much more active role, bidding into the wholesale market on behalf of end-customers, injecting energy from distributed resources (local generation or battery storage) and controlling demand in response to wholesale price signals.[22]

36. There would almost certainly be a number of associated issues to address. The distribution network would likely have to develop the capability to monitor and control two-way flows on its network. This could require a sizeable investment in new technology. In addition, decisions would have to be made about the granularity of the pricing arrangements in time and space. Should the locational prices in the distribution network be taken down to the zone substation level, the feeder level, the distribution transformer level, or to the individual house? This will require a trade-off between the benefits of more efficient price signals, on the one hand, and the higher transactions costs and the risk of market power, on the other. Distribution networks would almost certainly have to monitor and report on congestion as it occurs, and to publish forecasts of congestion on their networks into the future.

37. There is some recognition in Australia of the need to move in this direction in the medium and long term. In recent months the AEMC has initiated an inquiry to “explore how the evolution of a decentralised market for electricity services at the distribution level may occur” including “what changes to the regulatory framework, distribution

[20] As we have noted earlier, the existing wholesale market does not correctly price transmission constraints, due to the “regional” design of the market.

[21] See Biggar and Reeves (2016). Also Knieps (2016): “As more and more local communities are jumping on the environmental bandwagon of microgrids, there seems to be no alternatives for electricity utilities of the future to incentivize presume activities by proper pricing signals. … The time is right to introduce disaggregated nodal pricing, taking flexible flow patterns in smart grids, and decentralized interaction between different network levels”.

[22] It is possible that, in the interim, a more limited, geographically focused market or markets could be established to effectively price localized distribution constraints as they arise.

system operation and market design more broadly might need to occur to accommodate this evolution".[23]

38. But, in the short-term, we remain a long distance away from this goal. As noted above, following recent changes in the Rules distribution businesses in Australia are required to submit a "Tariff Structure Statement" which sets out how the networks propose to structure their tariffs for the next five years. Despite the fact that these distribution network tariffs are supposed to be cost reflective, the degree of movement towards cost-reflective tariffs to date has been negligible. In part this is due to a lack of adequate metering infrastructure, and in part due to inertia and political sensitivity.[24]

39. For the next five years, many distribution businesses propose to continue to use declining or inclining block tariffs, or flat tariffs which are not cost reflective at all.[25] Even in the state of Victoria, which has completed a mandated roll-out of smart meters, the distribution businesses have not proposed truly cost reflective tariffs. Instead, the distribution businesses have proposed "demand-based charges" which depend on each customer's own peak consumption in a month. Demand-based charges are not cost reflective.[26] In any case these tariffs are only offered on an opt-in basis. It remains to be seen whether these new, optional tariffs will have any material impact on retail contracts.[27]

40. It is worth emphasising that the development of dynamic locational marginal pricing of distribution networks does not imply that end-customers would directly pay the resulting volatile and time-varying charges. As noted above, end-customers do not currently pay the existing volatile time-varying wholesale price for energy. Retailers provide the interface between the time-varying wholesale price and the structure of end-customer tariffs that the end-customer chooses to pay. Some customers may be prepared to face a time-varying price; other customers may prefer to be insulated from all wholesale price risk; but either way, in a competitive market some retailer would offer a corresponding retail contract. Policy makers need not be concerned about the structure of the arrangements between the retailer and the end-customers. As long as retailers are exposed to the correct locational price for delivered electricity at the door of the customer, competition between retailers will drive them to offer an efficient bundle of services that end-customers desire.[28]

[23] AEMC (2016). The AEMC's draft report on this issue was published on 6 June 2017.

[24] It is also possible that one of the barriers to moving to more cost-reflective pricing is not the sensitivity of temporal differentiation of prices (although that is a sensitive issue) but the sensitivity associated with geographic differentiation of prices. Remote and rural customers in Australia have historically paid the same prices as urban customers. A move to cost-reflective prices potentially would require the unwinding of cross-subsidies.

[25] See, for example, Ausgrid Tariff Structure Statement.

[26] See, for example, Cicchetti (2016).

[27] There is some recognition of the need to go further in tariff reform. Gilbert and Tobin (2017) observe: "The next critical phase in tariff reform is to develop signals (both temporal and locational) that reward customers for DER investment and demand response".

[28] In order for retailers to play this role effectively they must have access to hedging instruments which allow them to hedge the risk of price differences across locations. The creation of dynamic network prices therefore should be associated with the creation of hedging instruments which allow retailers to hedge those price differences. See Biggar and Reeves (2016).

41. Developing mechanisms for efficient, dynamic pricing of distribution networks remains one of the most important policy challenges facing the electricity sector.[29]

3.2. Pricing of embedded generation and peer-to-peer trade

42. There is one, specific, element of the pricing of distribution networks which deserves further discussion in its own right: The question of pricing of power *injected* into the distribution network.

43. A feature of the current electricity market transformation is the decentralisation of generation, from large, centralised generating stations to small, embedded generators located close to (or co-located with) the end-customers, such as roof-top solar PV. In addition, the increasing penetration of battery storage and electric vehicles raises the possibility that end-customers may not just withdraw power from the grid but inject power from time to time.

44. This raises the fundamental question of the appropriate tariff for the export of locally-generated (or locally-stored) power. As before, economic theory provides some guidance. Economic theory is clear that the wholesale price paid for exported power at a location should be *equal* to the wholesale price paid for power withdrawn from the same location. As noted above, both prices should be dynamic, and time-varying and reflect the marginal cost of production of electricity and delivery to that location.[30]

45. This is the current policy in Australia at the transmission network level. Large customers can connect to the transmission network and either inject or withdraw power, paying (or receiving) the relevant local nodal price for that location. In principle, the same principles apply to electric power injected or withdrawn at the distribution network level. End-customers should pay (or receive) the same tariff for power which that withdraw (or inject) from the distribution network. In a sense, therefore, the pricing of power exported to the distribution grid introduces no new issues. Provided we have correctly priced power withdrawn from the grid, we have also correctly priced power injected into the distribution grid – these prices should be equal.

46. In practice, however, we are a long way from this theoretical ideal. In practice, many customers with solar PV in Australia are paid a specific, separate tariff for power they inject to the network, known as a “feed-in tariff”. This tariff is typically flat (time-averaged) and independent of wholesale market conditions. For a few years, the feed-in tariff was set at a substantial premium to the standard retail tariff. However, such programs have all closed to new entry (and some have closed entirely[31]). Nearly all new solar customers in Australia are paid a flat feed-in tariff which is roughly one-third to one-half of the standard retail tariff.

47. Both the level and the structure of the feed-in tariff have important consequences for end-customers decisions about investment in local generation and battery storage. A flat (non-time-varying) feed-in tariff favours generation which can produce continuously

[29] One further point is that we have only discussed here the energy ($/kWh) component of the network tariff. Distribution networks will likely have to adopt other charges, such as fixed ($/day) charges in order to recover their total costs. The structure of these other components of the network tariff are not discussed here.

[30] See chapter by Biggar and Dimasi (2017).

[31] See, for example, NSW Solar Bonus Scheme.

(such as solar PV), rather than generation which can best meet local needs to balance supply and demand at peak times.

48. In addition, where the feed-in tariff is above the retail tariff, end-customers have an incentive to export as much power as they can (that is, not to use any of the locally generated power for their own use). There are also strong incentives for separate metering (so-called "gross metering") of the local generated power.[32] Gross metering was historically the standard practice in Australia for customers on premium feed-in tariffs.

49. However, current feed-in tariffs are typically only a small fraction of the retail price. As a result, customers have a strong incentive to use locally generated power to offset on-site consumption before exporting any surplus. The customer also has strong incentives to invest in battery storage to reduce exports, even when that storage has little or no social value. In addition, the end-customer has a strong incentive to find other loads in the local area which can be supplied directly (offsetting the full retail tariff), rather than exporting to the grid and receiving the lower feed-in tariff. This gives rise to pressure for the creation of local micro-grids, or informal networks which bypass the local grid, even when doing so is socially inefficient.[33]

50. In the United States many states have a policy of "net metering" which allows customers to inject power into the network and to receive the same retail price they pay when they withdraw power from the network. The problem here is not the fact that the retail price for power withdrawn from the network is the same as power injected; rather the problem here is that both these prices are not cost-reflective. As long as the retail price is time-averaged, it does not give rise to efficient incentives regarding the use of or investment in local generation. This policy also exacerbates the threat of the death spiral discussed further below.

51. Around the world there has been increasing interest in the potential for allowing peer-to-peer trade between local generators and local consumers. As noted above, as long as the feed-in tariff is below the retail tariff, local exporting customers have a strong incentive to find other local customers with whom they can "trade" their exported power. Many new enterprises are exploring the application of "blockchain" technology to facilitate such local trading of energy.[34]

52. At one level, the creation of local electricity markets may have some benefits. It can help customers adjust to the notion that electricity is a dynamic commodity, with a price that varies through time. However, to date the proposed local electricity markets do not take into account local network constraints. This is a serious drawback. This limits the extent to which such markets can be used to ensure efficient use of or investment in

[32] In addition, if they could, end-customers have an incentive to find ways to power withdrawn from the network appear to be locally generated power which can then be exported back to the network. This might be achieved (perhaps) by using the network to charge local batteries which could then supplement the output of solar panels?

[33] In Australia rules prohibit the trade of electricity across property boundaries, making it more difficult to supply neighbours directly, but pressures to create such grid bypass remains. See Biggar and Dimasi (2017).

[34] For example, Power Ledger has undertaken a trial in Perth and in Auckland, New Zealand. LO3 Energy (responsible for the Brooklyn Microgrid) has opened an office in Byron Bay. In the US, a new organisation, the Energy Web Foundation, has been created to accelerate commercial deployment of blockchain technology in the energy sector. EWF is a partnership of the Rocky Mountain Institute and Grid Singularity, a blockchain technology developer specialising in energy sector applications.

electricity services. In the long term, the only way full peer-to-peer trading in the electricity industry can be established is through an extension of the existing market mechanisms (bid-based security-constrained economic dispatch) down to the local level.

53. The pricing of power exported to distribution networks remains one of the most important public policy issues facing the sector and will become even more important as end-customers increasingly take up battery storage technology.

3.3. Demand response services

54. Another public policy issue arising in the electricity market transformation is the pricing of demand response services.

55. As noted earlier, one of the major potential benefits of improved use of the distribution network is the potential for substantial savings in network investment. The Australian Productivity Commission has estimated that 20% of the capacity of a distribution network is used for only a few hours each year.[35] If scarce network capacity could be effectively rationed at times of network constraints, rather than inefficiently rationed through involuntary load shedding, there could be substantial economic savings through a reduced network build and higher network utilisation.

56. As we noted above, this is the primary argument in favour of efficient pricing of distribution network services. At times of local network congestion, the wholesale spot price for electricity should vary across locations, reflecting the scarce network capacity, and the rationing required to balance supply and demand in the presence of network limitations. In particular, where demand at a location increases to the point where the local network can no longer meet the local demand, we would expect that the local price for electricity to increase to a point necessary to curtail load, to balance supply and demand.

57. However, as noted above, we are still some distance from efficient pricing of distribution network services. For the most part, mechanisms do not exist to allow prices to increase to reflect local network constraints.

58. Nevertheless, it is still recognised that it may be significantly more efficient to look for a market response (increased local production or reduced local consumption) on the rare occasions when network constraints are binding, rather than to build more network infrastructure. In the absence of any mechanism to increase prices to balance supply and demand, network businesses must resort to *paying* customers to reduce their consumption or increase local production.

59. This is the idea behind most demand response programs. Individual customers located in an affected area behind a network constraint are typically paid for reducing their consumption relative to some baseline when those network constraints are binding. Done effectively, such demand response programs may efficiently defer network investment. These programs may therefore facilitate the electricity market transformation in the short-term – and indeed such programs are common in electricity markets around the world.

60. However, there are several reasons for concern about the proliferation of such demand response programs:

[35] Productivity Commission (2013).

- Such programs are open to gaming and strategic behaviour, through the definition of the baseline, against which the demand reduction is measured. End-customers have an incentive to act strategically to increase their consumption at certain times, in order to increase the baseline against which a demand reduction is measured.
- Such programs subsidise investment in assets which can contribute to demand response, even if those assets are causing the need for the demand response program in the first place. A customer who installs a new high capacity AC unit both contributes to the need for a demand-response program and potentially benefits by being paid to reduce consumption below a pre-defined baseline. In the long-run this exacerbates the underlying problem.
- Such demand response programs are incompatible with long-term efficient pricing. These demand-response programs create entitlements and expectations which will be hard to unwind as we move to more efficient pricing in the future.

61. Transitioning from demand-response programs in which customers are paid for reducing their consumption, to programs in which customers must pay to increase consumption at peak times, is one of the most significant public policy problems facing the sector.

3.4. Visibility of distributed resources and forecasting of net demand

62. As we have seen, there is an expectation that in the future many end-customers will have a range of devices and appliances which control, modify, and augment their use of electricity, particularly in response to wholesale price conditions. If a customer injects power to the network, that injected power may be observed and metered by the retailer and distributor, but if a customer installs solar PV, or a battery, or installs a smart thermostat, or a building energy management system, that decision may be entirely invisible to all other market participants.

63. This is important. The wholesale market must be capable of balancing supply and demand. In addition, the wholesale market must ensure that flows on all network elements are kept within their physical bounds. But it is not possible to effectively balance supply and demand, or to keep flows within physical limits, without good short-term forecasts of consumption – both in aggregate and at different locations on the network.

64. In 2015 one of the market participants in Australia proposed a change to the Rules[36] which would require all price-sensitive load greater than 30 MW to bid into the central dispatch. The proposal argued that this would result in better load forecasts, better short-term price forecasts, and better forecasting and management of network constraints. The AEMC has not yet made a decision on this Rule Change proposal.

65. But these issues are important not just for large loads, but for all loads. In the future the price sensitive load of small customers could easily exceed 30 MW. At present, this price-sensitivity is essentially invisible to the market and the market operator.

66. In the NEM, responsibility for forecasting small customer load falls on AEMO. But increasingly AEMO finds that it does not have the information to carry out that forecasting accurately:

[36] AEMC Non-scheduled generation and load in central dispatch Rule change.

> *"AEMO has found that the information available to support technical modelling of power system performance is progressively becoming inadequate as small, distributed energy resources increase in dominance to the point where they have a material impact on the performance of the transmission grid. AEMO considers that this issue, if left unaddressed, will rapidly grow and require conservative constraints to be imposed on the operation of the transmission system to maintain power system security in light of uncertainties as to DER characteristics".*[37]

67. What is the best way to introduce visibility of small customer behaviour? Probably the best approach is to require retailers to submit a bid curve on behalf of their customers.

68. When the NEM was established it was assumed that only large generators (and perhaps some large loads) would participate directly in the wholesale market. With the increasing proliferation of distributed resources, this assumption needs to be revisited. Since retailers have a direct relationship with the end-customers, it is probably desirable to require retailers to participate directly in the wholesale market on behalf of their customers, by submitting a bid curve for electricity. That bid curve could reflect the retailers' information about the distributed resources available to the end-customers, and their responsiveness to wholesale prices. This would be an important step forward for the NEM.

3.5. The exercise of market power in wholesale markets

69. It is widely recognised that wholesale electricity markets have historically tended to be prone to the exercise of market power.[38] This is due to a number of factors, including the fact that traditionally electricity could not be easily stored, and the lack of responsiveness of electricity to the spot price in the short run.

70. From time to time, a few generators in the Australian NEM have been able to exercise market power, particularly at peak times when the supply/demand balance is tight, and in the "fringe of NEM" regions at times of binding transmission constraints. The prevalence of market power has declined in recent years due to an overall drop in demand for electricity, and the increasing penetration of wind and solar generation. However, the potential for market power remains, especially at times when wind and/or solar output is low.

71. The extension of dynamic network pricing arrangements to the distribution network will almost certainly enhance the opportunities for market power. As locational marginal prices are determined at increasingly granular locations, the potential geographic size of the market becomes smaller and smaller. It becomes increasingly likely that some customers (generators or loads) will be able to exercise market power at certain times.

72. At the same time, market developments may reduce the opportunities for the exercise of market power. Increasing penetration of battery storage may allow for short-term deferral or bringing forward of energy consumption, reducing the temporal exercise of market power which currently occurs. In addition, the increasing penetration of smart

[37] AEMC (2017b).

[38] See Biggar (2011).

appliances may significantly increase the responsiveness of demand to local prices, increasing the elasticity of demand and again, reducing the opportunities for market power.

73. However, the balance of these factors is uncertain. As we move towards further refinement of dynamic pricing of the distribution network, close monitoring of the market will be required to ensure that market power problems do not undermine the success of further reforms.

3.6. Transitional pricing issues

74. Good public policy must pay attention not only to the long-term goal, but the transition path to get there. Many existing customers have made a substantial sunk investment in reliance on the existing tariff structures and levels in the electricity sector. Changes to tariff structures or levels may place those existing customer investments under threat. Governments around the world have been understandably reluctant to move too quickly to more efficient tariff structures and levels.

75. In Australia, for example, the Victorian government recently required that the distribution businesses continue to offer the current tariff structure and that any new cost-reflective tariffs must be offered on an "opt-in" only basis.[39]

76. In order to maintain the confidence of consumers it will be necessary to develop transitional arrangements which ensure that consumers are not left materially worse off in the transition to more dynamic, cost-reflective pricing arrangements. In Australia, this task is made more complex by the fact that end-customers do not directly pay network tariffs – instead these are mediated through the retailer. The actual tariffs paid by the end-customer are not within the control of the network or the regulator.

77. In addition, ensuring that an individual customer is not left worse off may require taking into account that customer's total consumption or load profile. This may lead to a proliferation of tariffs during the transition – with different tariffs for different customers with different load profiles. The presence of geographic averaging in existing tariffs is a further challenge, as such cross-subsidies will need to be unwound over time.

78. Transitional pricing issues also apply to pricing of embedded generation. As noted earlier, small-scale embedded generation in Australia is typically paid a simple flat time-averaged feed-in-tariff. There are some moves to vary this tariff by time of day[40]. But a fully cost reflective tariff for injected power would involve substantially more time variation, reflecting the changing supply/demand balance and changing network conditions over time. In particular, the price paid for injected solar could be substantially lower at certain times – particularly at times when solar is producing. Recent experience in California has seen the wholesale spot price turn negative during the day when the sun is shining.[41] Transition to a truly cost-reflective feed-in-tariff could require substantial adjustment by end-customers. That adjustment should be carefully taken into account by policy-makers.

[39] See http://delwp.vic.gov.au/energy/electricity/managing-electricity-demand

[40] See ESC, http://www.esc.vic.gov.au/project/energy/22790-inquiry-into-the-true-value-of-distributed-generation-to-victorian-customers/ .

[41] See the blog by Catherine Wolfram, "Is the duck sinking?"

3.7. Retail pricing margins and effective competition

79. In principle, electricity retailing is a competitive business. Barriers to entry are fairly low and there are a large number of retailers in the Australian electricity market. Nevertheless, concerns have repeatedly been expressed that retail margins are too high.[42] Paradoxically, the retail margins appear the highest in Victoria – the state which liberalised the earliest and which has the longest experience with full retail contestability.

80. There are various possible reasons for the observed high retail margins. It is possible, for example, that there remain a portion of end-customers who are passive, and who fail to actively seek out the best deals.[43] Experience shows that customers who remain on the historic "standing tariff" end up paying considerably more than customers who switch to a more competitive offer. Even customers who switch to a competing offer may find that the competitiveness of that offer is eroded over time, so that maintaining good value for money requires on-going customer attention.

81. Another possibility is that comparing retail offers is too complex for some consumers. Even at best a retail electricity contract involves a minimum of two "moving parts" – the "fixed charge" ($/day) and the variable charge ($/kWh). But most electricity retail contracts feature many more components, including different charges for different "blocks" of electricity, time of day, or time of week, or season of the year. More sophisticated retail contracts may include so-called "demand" based charges (based on a customer's peak consumption), with a varying peak "window" for the demand charges across days of the week or seasons of the year. Some contracts may involve a fixed charge based on forecast peak consumption (kW) or forecast consumption (kWh). Contracts also vary with the proportion of "green" electricity, with the size of the feed-in tariff for injected solar power, and with pay-on-time discounts. Comparing different retail electricity contracts is tricky even for a relatively highly engaged consumer. As noted earlier, Australian governments have attempted to address this by creating comparison tools, such as price comparison websites. But these may be of less value as the degree of customisation or tailoring of retail contracts increases.

82. Predicting the future of retail contracts is tricky. Retail contracts may become significantly more complex in future as retailers seek to take control of end-customer devices and appliances, such as battery storage, electric vehicle charging, and control of air-conditioning and other devices. At the same time, there is a trend towards very simple fixed-bill contracts.[44] It is not clear which of these trends will predominate.

83. The ACCC has been asked to undertake a major review of the retail electricity market to determine whether or not there is effective competition. It remains to be seen whether public policy intervention is required and what form that intervention might take. Identifying effective measures to improve competition in the retail electricity market is one of the more challenging policy issues facing the sector.

[42] See Ben-David (2015), Grattan Institute (2017).

[43] There may even remain some customers who fail to recognise that they have the right to switch to another retailer. See St Vincent de Paul (2016).

[44] See, for example, Origin's Predictable Plan which features fixed monthly payments independent of usage.

3.8. Stranded assets, the death spiral, and the boundary of monopoly regulation

84. Another fundamental public policy issue relates not so much to the *structure* of network tariffs but to their *level* – and in particular, their level relative to the cost of the alternative – self-supply of electricity.

85. Historically, for most customers, the possibilities for self-generation of electricity were so limited, and the cost so prohibitive, that taking electricity from the grid was the only reasonably prospect for all except the most remote customers.

86. Over the past ten years there has been a substantial year-on-year reduction in the price of solar PV. Furthermore, there is evidence that the price of battery storage is falling at a similar or even faster rate. It has been suggested that in the near future some end-customers (or groups of end-customers, such as a new subdivision) will find that some combination of solar + battery storage + local generation can supply their electricity needs with a reliability comparable to the existing grid and at a price which is similar to or less than the on-going charges associated with connection to the grid. In other words, it has been suggested that the time is not too far off (if it is not here already) where self-supply of electricity through a stand-alone (non-grid-connected) system will be a viable commercial option for some or even many end-customers.[45]

87. Even advocates of grid defection recognise that self-supply will not be a viable option for *all* end-customers. Some customers lack the roof space for solar PV and noise, public safety, and zoning limitations may prevent other forms of generation (e.g., fuel cell or diesel). In addition, the scope for bypass depends in part on the electricity demand of the customer. Self-supply may not be an option for large electricity consumers such as residential consumers with an electric vehicle or a heated swimming pool.

88. Nevertheless, the potential for self-supply of electricity has fundamental implications for the regulation of network services. Specifically, the presence of an outside option (self-supply) has fundamental implications for:

- The geographic extent of the shared network and the boundary between monopoly and competitive services;
- The geographic averaging of tariffs;
- Stranded assets and asset re-valuation; and
- Network investment decisions.

89. First, and most obviously, the presence of a self-supply option has implications for the geographic scope of the shared network. Network costs depend quite strongly on customer density. The cost per customer to provide network services is significantly higher in remote and rural areas than in urban and suburban areas. On the other hand, self-supply costs do not vary much with customer density (and may be lower in areas where land is cheaper). The geographic boundary of the network should be determined by

[45] The point where stand-alone solar systems are commercially viable alternatives to grid-supplied electricity is known as "grid parity". Some have argued that grid parity for solar PV systems has already been reached in most countries. The Australian Minister for Energy has noted that having a significant number of Australians independent of the grid is inevitable, the networks have raised concerns about grid defection, and some have claimed that solar+battery will be cheaper than grid connection in 2017. More recently, one of the network businesses has suggested that the price of solar+battery is now around half of the retail tariff in South Australia.

where these two curves cross. As self-supply costs decline, the geographic coverage of the network should reduce.

90. Another way of expressing the same idea is to note that where self-supply is a viable alternative to taking supply from the network, the network in effect faces competition. In such circumstances there is no longer a need to regulate network services. The point where self-supply becomes a viable alternative to network supply therefore defines the boundary of the monopoly service.

91. Either way, as the costs of self-supply decline, the geographic scope of the monopoly service area should shrink. In practice this means that the existing network should not be extended to serve new customers at the fringe or, where an existing asset comes up for replacement or renewal, it may be cheaper for those customers to invest in stand-alone systems, rather than to take service from the grid.

92. Ideally end-customers would face the correct private trade-off between stand-alone supply and taking service from the grid. This can only occur where the network tariffs are geographically de-averaged and reflect the costs of serving those customers. In practice, it is common to engage in geographic averaging of network tariffs over large geographic areas, resulting in remote or rural customers paying less than their cost for the use of the network. In this circumstance, customers left to their own devices will not make the most efficient choice. One of the policy challenges facing the electricity sector is unwinding that geographic averaging over time. There have been some proposals in this area[46], but to date no serious action.

93. The self-supply option need not only affect the pricing of customers on the fringe of the grid. Depending on the structure and level of tariffs, customers within the core of the grid may find that they have an incentive to switch to self-supply. For example, where network revenues are recovered primarily through usage (per kWh) charges, larger customers may find that it is commercially viable to disconnect from the grid.

94. However, as long as the incremental revenue received from that customer exceeds the incremental cost of supplying that customer, it is socially preferable for that customer to continue to receive service from the grid, rather than disconnecting. This can be achieved by lowering the tariffs to that customer below the point at which self-supply is a viable outside option.

95. In other words, even for customers within the core of the grid, the outside or self-supply option places limits on the design or structure of tariffs. As a general principle, for customers in the core of the grid, the tariffs charged to a customer should not exceed the level at which the customer has an incentive to switch to self-supply. The outside (self-supply) option places an effective cap on the tariffs that can be charged to customers in the core of the grid. A recent report argues for the establishment of a new tariff for customers who have the potential to set up a Stand-Alone Power System[47]. The move to cost-reflective tariffs will help this process, but the need to pay attention to the threat of grid defection remains.

96. Where there are only one or two customers who face a viable alternative in self-supply, this could potentially be addressed by allowing these customers a discount on the

[46] See, for example, Giles Parkinson, RenewEconomy, "AGL's novel proposal to cut network costs: pay by the metre", 2016.

[47] See Energeia (2016).

standard network tariffs. In Australia, the electricity Rules allow for large transmission customers to be granted a "prudent discount" on their transmission charges where they can show that that have a feasible bypass opportunity.[48] The same principle should apply at the distribution network level.

97. But what if a large number of customers face a viable alternative in self-supply? In this case there may arise a serious regulatory problem.

98. Where a sufficient number of customers face an outside (self-supply) option, the network business may be forced to lower tariffs to those customers resulting in a material loss in revenue. In principle the network business could seek to preserve its revenue by raising prices on the remaining customers. But this is highly undesirable for two reasons. The first is that higher prices on the remaining customers will encourage those customers to disconnect from the network, potentially accelerating the revenue decline, resulting in what is known as a *death spiral*. The second reason is that increasing the prices on the remaining customers is a breach of the regulatory contract which is essentially a promise to the customers that regulated prices will not increase except to reflect changes in costs.

99. If the network business is forced to lower prices to some customers, and cannot raise prices to others, it will no longer be able to recover a normal return on its historic investments.[49] This is also a breach of the regulatory contract – in this case, the promise to the regulated firm that it will be allowed to receive sufficient revenue to earn a normal return on prudent investment. Technological change in the electricity sector is challenging precisely because it brings into conflict fundamental promises in the regulatory contract.

100. If technological change sufficiently reduces the prices of alternatives to network service, forcing a reduction in tariffs to grid-connected customers, without an increase in the tariffs to other customers, a breach of the promises to the regulated firm may be unavoidable. Although it is not essential, it is probably desirable for this permanent reduction in future revenue to be reflected in a downwards revaluation in the regulated firm's regulatory asset base. In other words, asset base revaluation can be a sensible and appropriate component of a well-designed regulatory contract.[50] Of course, where the regulated firm is exposed to the risk of asset-base revaluation this risk may need to be reflected in the firm's cost of capital.

101. The New Zealand Commerce Commission expresses the issue as follows:

> *"We acknowledge that there may come a time when, due to the development of emerging technologies or other circumstances, … the application of [the legislative] principles is no longer sustainable. Over the longer term, this could be one possible outcome … of the continued uptake of some emerging technologies that may act as substitutes to the regulated service. The market risk, in that context, is that if enough consumers disconnect from the network, the remaining consumers will not be willing or able to pay the prices that would be*

[48] Rules 6A.27.1.

[49] Cornell and Kihm (2015): "The emergence of competitive alternatives to energy and capacity supplied by the bulk power system … will dramatically increase customers' elasticity of demand for power, leading to downward pressure on both utility profitability and cost structures. After a century of utility concerns over whether rate increases will be high enough to allow full cost recovery, the emergence of elastic demand for electricity will shift the focus to whether utility costs are simply too high to be recoverable".

[50] Grattan Institute (2013).

required for suppliers to [receive a normal return on their investments]. There may also be a political risk in that if circumstances change to a sufficient extent, the government may intervene and amend or repeal [the regulatory framework]. If such a 'tipping point' occurs, regardless of any action we might take, suppliers may not be able to [earn a normal return on investments].'[51]

102. It is my understanding that for the majority of customers the threat of grid defection is still more a theoretical possibility than a real prospect. However, this threat is sufficiently real that it is worth considering the implications at least for any new investment by the regulated network businesses. In some circumstances it may be possible to bring forward or accelerate depreciation to reduce the risk to which network businesses are exposed. However, these issues should be considered now and not deferred into the future.

3.9. Structural separation of network businesses

103. Another key policy area in the electricity sector is the question of *line-of-business restrictions* on regulated network businesses. This is also often framed as the question of structural separation between monopoly and competitive activities.

104. In Australia we have seen that there has been strong interest from network businesses in the direct provision of distributed energy resources, particularly where those resources can be used to defer network investment[52]. In particular, network businesses have shown a high degree of interest in installing battery storage in place of network upgrades.[53]

105. Should network businesses be allowed to own and operate distributed energy resources?

106. There is widespread acceptance that many (if not all) distributed resources are capable of being provided through a competitive market. That is, there is scope for competition in the provision of battery services, local generation, smart appliances and so on. There is agreement that these services should not be monopolised by the network businesses (that is, included within the scope of monopoly services).[54] But should regulated network businesses be allowed to provide these related competitive services at all?

[51] Commerce Commission (2016b), "Input methodologies review decisions: Framework for the IM review", 20 December 2016

[52] For example, the distributor in SA has announced a solar+storage trial. QLD distributors are trialling solar+storage in Townsville, Cannonvale and Toowomba.

[53] For example, Ergon Energy (QLD) has installed battery network support services on 20 of its single-wire rural services. Energex (QLD) is installing battery services to support increasing penetration of solar in the Brisbane area. Powercor (Victoria) installed a 2MW battery on a feeder near Ballarat. Similar events are taking place in New Zealand: Commerce Commission (2016), page 31 reports that "In October 2016 Vector commissioned Asia Pacific's first grid-scale Tesla Powerpack battery storage system to be integrated into a public electricity network. It is reported that Vector's $5m investment in this battery will avoid a conventional $12m upgrade to existing network infrastructure".

[54] The Council of Australian Governments recently submitted a Rule Change request to the AEMC to make clear that these new technologies would not be classified as non-contestable services. See AEMC (2016), "Consultation paper: National Electricity Amendment (Contestability of energy services) Rule 2016", 15 December 2016

107. There are well known public policy concerns associated with allowing regulated businesses to provide competitive services. These concerns have been well documented by OECD/DAF/COMP/WP2 over the years.[55] These concerns come down to two fundamental issues:

- Cross-subsidisation – that is, allocation of some of the cost of the competitive services to the monopoly service, potentially increasing the price for the regulated services. Although cost allocation and ring-fencing rules are common, it can be very difficult for a regulator to detect and prevent cross-subsidisation in this form.
- Anti-competitive discrimination. In many cases the related competitive service is reliant on access to the monopoly facility in some way. For example, in the electricity sector, rival electricity storage facilities or rival local generation facilities require access to the local distribution network. A regulated business which has control over the local distribution network may be able to use that control to restrict or hinder the activities of its rivals in the competitive services. For example, a local distribution network may insist that rival products undergo lengthy safety certification or licensing procedures, or may insist on additional features or compliance with non-standard or idiosyncratic codes. Alternatively, a local distribution network may fail to maintain distribution lines which are necessary to service rivals, while ensuring high levels of reliability on distribution lines serving its own affiliate companies. Experience in many industries has shown that competition authorities have difficulty identifying and prosecuting such forms of anticompetitive behaviour. Even where a prosecution is initiated, the incumbent network business may be able to use the legal process to delay compliance with the competition law.

108. Importantly, it may not even be necessary for the incumbent regulated business to engage in cross-subsidisation or anti-competitive discrimination in order to deter competition – the mere threat that the regulated business will engage in such activity may be enough to deter rivals from entering the related competitive market. It is hard for a competition authority to prosecute anti-competitive behaviour which, although a real threat, has not yet actually occurred.

109. For these reasons, in many regulated industries, regulated monopoly businesses are not allowed to participate in competitive businesses. These are known as line-of-business restrictions or as structural separation.

110. These issues were widely recognised in Australia in the past. The 1994 report by the Hilmer Committee which laid the foundation for the competition policy reforms in Australia explicitly mentioned concern about cross-subsidisation and anti-competitive discrimination. As noted earlier, these issues were instrumental in decisions about industry structure in the early years of the reforms of the electricity sector. Those reforms split up the historic vertically-integrated electricity companies in each state, creating separation generation, transmission, distribution, and retail businesses. Subsequently we have seen a degree of re-integration of the generation and retail sectors, but to date there has been no serious attempt to allow regulated transmission businesses to compete in related competitive sectors. Increasingly, however, there is a strong interest by distribution businesses in the direct provision of distributed energy resources.

[55] See OECD (2001).

111. These issues are well known to OECD/DAF/COMP/WP2. This committee was a pioneer in developing the OECD Recommendation on Structural Separation. In the associated report WP2 highlighted examples of the kind of behaviour that was occurring at in the electricity industry. Citing the FTC, that report notes:

> *"Several years of industry experience now appear to confirm this concern that discrimination remains in the provision of transmission services by utilities that continue to own both generation and transmission. Complaints about – and actions by FERC to remedy – discriminatory treatment favouring the generation assets of transmission owners are widespread. These complaints allege subtle forms of discrimination, including, for example, biases in posted assessment of transmission capacity available to service independent merchant transactions. Accordingly, we support FERC's assessment that behavioural rules have not provided the degree of competitive benefits that FERC sought to engender when it introduced competition in wholesale electric power markets".*

112. These concerns by the FTC primarily relate to the transmission sector. However there is a risk that the same issues will arise at the distribution sector. Already, as we have noted, there has been strong interest by distribution businesses to provide related competitive services, particularly battery storage.

113. There is an overlap between these structural separation issues and the pricing issues discussed earlier. As noted earlier, the overall objective is to achieve efficient use of and investment in new devices and appliances, such as battery storage. In principle, these efficiency objectives could be achieved through price signals. In principle, dynamic price signals would provide the correct signals to an independent third party about when to charge and discharge a battery, and whether to invest in the battery in the first place. In such circumstances there is, in principle, no reason for a distribution network to be involved in the provision of distributed resources at all – the distribution network can focus on getting the prices right, allowing the investor and entrepreneurs to decide how best to respond.

114. But where such price signals are absent, it still may be efficient for a distribution business to draw on the services of, say, a battery from time to time instead of upgrading the distribution network. This raises the question whether the distribution network should be allowed to own the battery facility, or whether it should be required to tender for the services from a third party?

115. In Australia there has been a range of views about the role of network businesses in these contestable services. The network businesses have argued that structural separation considerations set out in the Hilmer report no longer apply and that they should be able to provide battery services and other contestable services.[56] Consumer groups have argued that network businesses "should only be able to own batteries through ring-fenced businesses". A group of retailers and energy service businesses have asked the AEMC to consider a Rule Change which would prevent networks from investing in contestable services on the property of end-customers.[57]

[56] See, Synergies and Yarrow (2016).

[57] See AEMC (2016), "Consultation paper: National Electricity Amendment (Contestability of energy services – demand response and network support) Rule 2016", 15 December 2016. In New Zealand, the Commerce Commission has declined to impose structural separation solutions as not within the scope of their powers under the Commerce Act. Commerce Commission (2016), page 70.

116. My view is that lesser forms of separation, such as accounting separation or legal separation, will not overcome the strong incentives on the regulated network businesses to engage in anti-competitive discrimination. The competition authority or the sectoral regulator might be able to control some forms of anti-competitive behaviour, but experience shows that this is not likely to be fully effective. If we seek to promote competition in related services, network businesses should not be allowed to own or operate competitive services. Where the network business sees a need to procure services to defer a network upgrade (for example, because the signal for the services is not provided through efficient prices) the distribution business should do so through an arms-length tender process. The distribution business should not be allowed to compete in that tender either directly or through an affiliate. This requirement to go out to tender for such competitive services will raise transactions costs to a small degree. There may also be costs associated with coordination between network and competitive operation and investment. However, in my view these costs are not so high as to justify allowing distribution network businesses to compete in these markets.[58]

117. This view, about the importance of structural separation, is echoed by the MIT Energy Initiative:

> *"As experience with restructuring in the bulk power system has demonstrated, structural reform that establishes financial independence between distribution system operating and planning functions [on the one hand] and competitive market activities [on the other] would be preferable from the perspective of economic efficiency and would facilitate more light-handed regulation. …*
>
> *If financial independence is not established, several additional measures are critical to prevent conflicts of interest and abuse of market power. These include stricter regulatory oversight of distribution network planning and operation, legal unbundling and functional restrictions on information exchange and coordination between distribution system operators and competitive subsidiaries, and transparent mechanisms for the provision of distribution system services (such as public tenders or auctions)".*[59]

118. The AER has recently promulgated a guideline which sets out specific requirements regarding accounting separation and controls on co-location, co-branding, and on flows of information.[60] However the Rules do not allow the AER to prevent distribution businesses from providing these services entirely. It remains to be seen whether or not the ring-fencing obligations promulgated by the AER will be sufficient to control anti-competitive discrimination and cross-subsidisation as noted above.

---

[58] I am implicitly assuming here that the distribution businesses are regulated, for-profit enterprises. Where the distribution businesses are co-operatives or trusts, owned by the customers, these problems should (in principle) be small.

[59] MIT EI (2016), page X.

[60] See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-ring-fencing-guideline-2016

3.10. New markets: Balancing and inertia services

119. The existing wholesale electricity markets were designed at a time when the vast majority of generation in the wholesale market was directly controllable. Increasing penetration of intermittent (uncontrollable) generation sources raises the question of whether changes in the market design are required to continue to balance supply and demand.

120. As the penetration of intermittent generation increases, there is a greater burden on the remaining conventional controllable generation sources to "fill in the gaps". For example, the conventional generation may be required to ramp up rapidly as the intermittent generation scales back due to a fall in the wind, or the setting of the sun. The larger the penetration of correlated intermittent sources, the greater the ramp rate that may be required of conventional generation. The California "duck curve" is a famous way of illustrating the rapid increase in traditional generation required to offset the decline in solar generation in the evening.[61]

121. The wholesale spot market is designed to balance supply and demand. If there is a temporary shortfall in generation due to a lack of ramp rate capability, it would be expected that prices would spike, creating a reward for generators which are capable of fast ramping. However, although the existing wholesale electricity market rewards generators for their output, it does not directly reward generators with a high ramp rate. It is not clear that generators will be adequately rewarded for meeting the ramp rate demands of the market. Further reforms to the design of the wholesale market may be required.

122. This remains a theoretical concern. It may yet prove necessary to consider modifications to the pricing-and-dispatch mechanism in the NEM to take explicit account of ramp rates and to ensure adequate rewards to providers of ramp rate services.[62]

123. Of course, the electricity sector must be kept in balance not just on the order of the dispatch cycle (5 minutes) but also on much shorter timeframes.

124. Over very short timeframes the response of the power system to a change in the supply-demand balance is determined by its "inertia" – that is the extent to which the frequency changes for a given change in the supply/demand balance.[63] Historically large generators, with heavy equipment rotating synchronously with the system frequency naturally provided this inertia. However newer generators, such as wind and solar, do not naturally provide inertia. There is a risk that changes in the supply/demand balance may lead to frequency excursions outside the limits which generators can tolerate, leading to cascading failures.

125. An unusual weather event in October 2016 resulted in a blackout of the entire state of South Australia. The lack of inertia available at that time contributed to the severity of the event, by allowing the frequency to change faster than the available

[61] See, for example, https://www.greentechmedia.com/articles/read/the-california-duck-curve-is-real-and-bigger-than-expected

[62] See, for example, BAEeconomics (2017).

[63] This is measured through the ROCOF – the "rate of change of frequency".

response mechanisms could handle.[64] The Australian Energy Market Operator (AEMO) in its report on the South Australian blackout noted that:

> *"As the generation mix continues to change across the NEM, it is no longer appropriate to rely solely on synchronous generators to provide essential non-energy system services (such as voltage control, frequency control, inertia, and system strength). Instead, additional means of procuring these services must be considered, from non-synchronous generators (where it is technically feasible), or from network or non-network services (such as demand response and synchronous condensers). The technical challenges of the changing generation mix must be managed with the support of efficient and effective regulatory and market mechanisms, to ensure the most cost-effective measures are used in the long-term interests of consumers".*

126. It may yet prove necessary to increase the degree of inertia in the power system – either by mandating the provision of inertia in the connection agreements with generators, or by establishing a market for inertia.[65] In September 2016 one of the market participants has proposed a Rule Change to introduce an ancillary service market for inertia.[66]

3.11. Micro-grids and stand-alone networks

127. We noted earlier that technological change is increasing the potential for some customers to disconnect from the grid entirely. But even where complete disconnection is not viable, it is increasingly viable for groups or communities to establish self-contained networks which may be only weakly connected to the wider shared network. In recent years there has been a proliferation of interest in communities establishing such self-contained networks.[67]

128. The existing regulatory framework was established at time when there was an expectation that electricity would be generated at remote central generating stations and transported to customers over the shared transmission and distribution networks. Does that regulatory framework still apply in the context of micro-grids or stand-alone networks?

129. For example, although economies of scale in generation have come down, the scope for competition in generation may still be limited. Depending on its size, a micro-grid or stand-alone network may have few local generation sources and limited scope for competition. There may be no formal wholesale electricity spot price. There may also be little or no scope for competition between retailers. Should a micro-grid or stand-alone network be subject to regulatory oversight? If so, what form of oversight? What retail protections should apply? Should micro-grid customers enjoy the same retail rights as other customers in Australia?

130. If, as seems likely, the regulatory framework for micro-grids should be different to the rest of the network, there remain a number of questions about how to transition into

---

[64] AEMO (2017a). In response to these issues AEMO has established what it calls its Future Power System Security program.

[65] See, for example, AEMO (2017b), Hindsberger and Modi (2016).

[66] See http://www.aemc.gov.au/Rule-Changes/Inertia-Ancillary-Service-Market

[67] See http://reneweconomy.com.au/australias-energy-future-could-be-network-of-renewable-micro-grids-84534/

and out of this new framework. What conditions should be in place before a micro-grid can be established? Under what conditions should the micro-grid revert to becoming part of the shared network?

131. If the micro-grid retains a connection to the shared network there are also questions about the tariff for that connection. The AEMC has recently commenced a review of the regulatory framework for embedded networks.[68]

132. These are important and complex questions which have not yet been addressed in detail in Australia.

3.12. Assessment of network investment; coordination with private investment; payment for new investments required

133. The electricity sector transformation also gives rise to a number of public policy issues relating to investment in the regulated networks.

134. For example, existing distribution networks were largely designed with passive, one-way flows of power in mind.[69] Upgrading the distribution network to monitor and control two-way flows is likely to require a substantial investment in network monitoring and control facilities. The cost-benefit analysis on this investment has yet to be carried out. There are several other questions to be resolved including: who should pay for this investment and how, whether parts of the distribution network should be capable of operating in "island" mode following a planned or unplanned network outage, and the procedure for reconnecting that islanded part of the network to the remainder of the network, once the service is restored.

135. In addition, as we have seen, we would like end-customers to make efficient usage of and investment in a range of distributed resources. But these decisions must be coordinated with network investment decisions. It makes no sense for a battery service provider to install a battery in a part of the network where it can respond to network constraints, only to have the network service provider upgrade the network, thereby eliminating the constraint.

136. It is essential therefore, that distribution networks make transparent the likely present and future points of congestion on the network, and the steps that it will take to alleviate those constraints and when. These processes already exist at the transmission network level in Australia. Transmission network service providers are required to publish a "statement of opportunities" highlighting where a tightening supply/demand balance or transmission constraints may create opportunities for private entrepreneurs. These processes will need to be reproduced at the distribution network level.

137. Furthermore, network investment is also often a complement to private investment in, say, renewable generation. It makes sense for network businesses to coordinate private investment to reduce the need for associated network investment. For example, the Queensland transmission network business has "adopted a 'clustering'

[68] AEMC Review of regulatory arrangements for embedded networks.

[69] The Energy Networks Association points out: "Many customers will never see the dramatic changes needed in the distribution network's planning, operation and design. Most would be surprised to know the 730,000 km distribution network was built to be relatively passive, for a one-way electricity flow, with limited sensors in the low voltage network. In most states, we can't measure when most of us use energy." John Bradley, CEO of ENA, Address to the All Energy Conference, Melbourne 4 October 2016.

model for shared assets designed to reduce connection infrastructure costs”. It has mapped its network to identify potential areas where there is both existing network capacity combined with high solar radiation levels. In these Renewable Energy Zones (REZs), multiple proponents could connect to the existing network through ‘shared assets’ reducing their project costs.

138. At the same time there must be processes in place which ensure that regulated network businesses do not “overbuild” capacity, thereby wiping out the business case of private investors. At the transmission network level this role is played by the so-called “regulatory investment test” which ensures that investment cannot proceed unless it passes a cost-benefit test. There is a similar test for distribution.

139. There have been recent calls to “streamline” the regulatory investment test to ensure that it does not act as a barrier to new investment in transmission capacity. While the regulatory investment test should not be a burden on networks, any weakening of the regulatory investment test runs the risk of deterring private investment in generation capacity or other distributed resources.

140. There is particularly a threat from government-encouraged investment. Despite the development of micro-grids and stand-alone networks mentioned above, it is far from clear that the transmission network will be no longer required. Indeed, with increasing levels of wind and solar generation, it is theoretically possible that more investment in parts of the transmission network will be required. The Australian government is encouraging the consideration of new investment in interconnectors between regions to reduce the risks of blackouts.[70] This makes sense, but such investment must be subject to a commercial cost-benefit test, to ensure that new interconnector investment does not crowd out investment by private generators.

141. Finally, the transformation of the electricity industry will likely change the way that investment in distribution network is assessed. To date the distribution network has been expanded when the load grows to the point where the economic harm from load shedding outweighs the cost of the upgrade. This is perhaps acceptable where end-customers have little opportunity to respond to network conditions. However, in the future, with the potential for distributed battery storage and local generation, the economic harm from constraints on the distribution network should be assessed after end-customers have had an opportunity to develop their own responses.[71] With battery storage and local generation involuntary load shedding can be avoided, significantly reducing the economic harm from network constraints. The processes for assessing distribution network investments should take this into account. This could have significant implications for assessing optimal levels of reliability and the overall design of the grid.

142. In many cases alternatives to network investment (such as battery services, or demand response services), when purchased from a third-party provider, would be classified as operating expenditure rather than capital expenditure. Some commentators have expressed concern that under the existing regulatory frameworks in Australia network businesses may have a stronger incentive to choose capital expenditure options over operating expenditure options. Some commentators have suggested a move towards an approach used by Ofgem in the UK, known as the total expenditure or “totex”

[70] See, for example, the COAG review of the cost-benefit test for new transmission investment.

[71] This point is emphasised in the textbook by Biggar and Hesamzadeh (2015).

approach.[72] However, the arguments in favour so far have been impressionistic rather than reasoned. These issues are being considered by the AER.

3.13. Regulatory governance: Responsiveness of regulation and government confidence in the market

143. The last public policy issue considered here is, in some respects, the most important: The issue of regulatory oversight and governance of the sector. The long-run success of the electricity sector depends in large part on on-going sunk investment by market participants (producers, consumers, and networks). But that investment depends, in part, on confidence by the market participants in the effectiveness of the overall regulatory framework, and confidence that the government and the relevant regulatory agencies can make necessary and reasonable changes in the market in a timely, just and reasonable manner.

144. But, at the same time, the willingness and ability of the government to make timely and appropriate changes in the regulatory framework depends on the government's confidence in the ability of the market to deliver good outcomes.

145. As long as the market participants have confidence in the future they will continue to invest in response to market signals, and the government can have confidence that suitable outcomes will emerge, sustaining a "hands-off" approach. However, if market participants start to lose confidence in the future, they may cease to invest, causing the government to lose confidence in the ability of the market to deliver, leading to further market interventions. Alternatively, if the government starts to lose confidence that the market will deliver good outcomes for consumers, it may be tempted to intervene, threatening the confidence of market participants, again leading to further market intervention. There is something of a "virtuous circle" or "self-fulfilling prophecy" about confidence in the electricity sector.

146. Unfortunately, even at the best of times, energy-only electricity markets may be susceptible to government intervention. Electricity is an input into almost all commercial production processes and all lifestyle decisions (or "consumption processes"). The economic harm associated with involuntary outages can be very substantial. Even a short period of time of blackouts can result in calls for politicians to act. Politicians may want to be seen to be taking action to "keep the lights on". Such interventions are likely to undermine the incentives for private investment.

147. Even if there is no involuntary load shedding, energy-only wholesale electricity markets tend to be very volatile. Under normal operation, there may be periods of time when there is spare capacity in the market, and prices are moderate, followed by periods of time when capacity is in short supply and prices periodically reach very high levels. It may not be politically adequate to simply argue, following a blackout or episodes of high prices, that the "market is working as intended", especially if there is some suggestion of the exercise of market power. In other words, even in relatively normal times, energy-only electricity markets may be susceptible to the risk of government intervention.

148. But, arguably, we are not currently in "normal times".[73] There are many pressures building in the electricity sector in Australia, which potentially could undermine confidence in the sector and the regulatory framework:

[72] See, for example, Small Consumer Groups (2016), CEPA (2016), and Gilbert and Tobin (2017), page 41.

- Over the past decade, network tariffs have increased substantially, especially in NSW and QLD. This is due to a variety of factors, including prescriptive regulatory rules, weak cost control incentives under government ownership, tightening of reliability standards, and over-forecasting of demand. This has spawned a number of reviews, placing the sector under political pressure at a time when it is facing environmental and technological challenges.
- In recent years the wholesale energy price has increased substantially due to developments in the gas sector. The gas sector in Australia has been transformed in recent years by the opening of major LNG export trains, with a total volume of exports exceeding Australia's entire domestic consumption of gas. This has resulted in a many-fold increase in the domestic wholesale price for gas to a level which is at or above an "export parity" level. This is causing considerable disruption amongst large gas consumers, a substantial increase in the variable cost of gas-fired generation, and a substantial increase in the forward price for electricity.
- Uncertainty over environmental policy has had a chilling impact on conventional generation. The electricity sector is heavily influence by environmental – and especially carbon – policy. There has been substantial policy uncertainty in Australia about long-term carbon policy which has had a chilling effect on new thermal generation investment.[74]
- A material renewable energy target has forced investment in large amounts of wind power, to the point that the total wind generation may on occasion exceed the domestic load in the state of South Australia. This has created new challenges in the form of intermittency and lack of inertia.
- It is not clear that needed regulatory changes can be made in a timely manner. The regulatory institutions in Australia were arguably designed to allow incremental, measured changes. There is arguably a bias towards careful deliberation and conservatism. However, the electricity sector is potentially facing its largest transformation in decades. There is a question whether the regulatory framework is sufficiently flexible to make the needed adaptations in a timely manner. Furthermore, in Australia, electricity is a state (as opposed to federal) responsibility. Major change therefore requires agreement and coordination across state governments. There is a concern that achieving needed timely, coordinated, concerted action may prove difficult.

149. The next few paragraphs look at each of these issues in turn.

150. In Australia, as in many countries, the electricity sector is a major contributor to greenhouse gas emissions. The electricity sector is therefore often the target of, and highly influenced by, policies to curb emissions. Unfortunately, carbon abatement and renewable generation policies in Australia have been controversial and have not yet been settled. While there has been substantial investment in wind generation in response to a Renewable Energy Target program, there has been no consistent policy with respect to curbing the emissions of coal-fired generation. As a result, there has been no new investment in conventional thermal generation for many years, despite the retiring of substantial amounts of coal-fired generation. There is a risk that this lack of investment

[73] Gilbert and Tobin (2017) suggest that "the NEM faces a perfect storm that has been almost a decade in the making".

[74] Gilbert and Tobin (2017) assert: "Almost all new generation introduced to the NEM since 2005 has been supported by some form of government policy or explicit rebate or subsidy".

may contribute to a tightening of the supply-demand balance, leading to volatile pricing and potentially market power, particularly at peak times.

151. The AEMC has expressed concern that without effective clarity in emissions-abatement policies there is a risk that further government intervention will be prompted:

> *"Evidence from international markets suggests that if integration (that is, the maintenance of fundamental structures in the market that support investment and competition) does not occur, the impact on the efficacy of the price mechanisms, together with uncertainty and policy risk, will likely require on-going government intervention in otherwise well-functioning energy markets, transferring investment risk and costs onto consumers".*[75]

152. In a report commissioned by the AEMC, UK academic George Yarrow cites the previous Secretary of State, saying:

> *"'We now have an electricity system where no form of power generation, not even gas-fired power stations, can be built without government intervention'. Since that was exactly the position pre-privatisation, the implication is that GB has come full circle. The work of Ofgem and of earlier Governments has been undone and there is no reason to think that a policy approach that worked poorly in the 1960s, 1970s, and 1980s will work significantly better now".*[76]

153. The increasing penetration of intermittent renewable generation may force an increase in pricing volatility. It has been a suggested that this volatility will increase to a point that is "inconsistent with community expectations". Tim Nelson of AGL writes:

> *"Extreme pricing volatility, which is required for an energy-only market with high penetration of renewables, is inconsistent with real-world constraints and community expectations. A 2016 study found that the NEM would require a market price cap of between $60,000 and $80,000 per MWh for revenue adequacy if the system was supplied by 100% renewable energy – six times higher than today. Prices would need to be able to increase by a factor of around 1,500 in half an hour. … Continued use of an energy-only market while pursuing high proportions of renewable energy for climate change-related public policy purposes is likely to be unacceptable to generation financiers, retailers, customers and governments. … As such, reconsideration of the NEM's energy-only market design appears inevitable."*[77]

154. Some commentators (including Nelson) have suggested that consideration be given to introducing a "capacity market" into the Australian NEM.[78] A "capacity market" makes payments to generators who commit to making capacity available in the spot market in the future. In principle a capacity market can partially restore the incentives to invest where there are defects in the spot market (due to, say, a price cap). However the capacity market concept introduces a "central planning" element into the wholesale electricity market, reducing the benefits of establishing a wholesale electricity market in the first place. In addition, as long as a capacity market is under consideration, the policy

[75] AEMC (2017b), page 17.

[76] AEMC (2017b), page 18.

[77] Nelson (2016).

[78] See, for example, John Bradley 16 October 2016, Riesz and MacGill (2009), Gilbert and Tobin (2017), page 46.

uncertainty can further deter investment. An entrepreneur is unlikely to invest on the basis of the existing price signals alone if, by waiting, the same facility could also receive capacity payments.

155. It is important to recognise that government intervention in the electricity sector does not need to involve a change in the regulatory framework in order to deter new private investment – all that is required is that the government take an action which would not be taken by a private commercial enterprise. This might include a government-funded, or subsidised investment in a new generator which competes in the wholesale market, or investment in network augmentation that does not pass a traditional cost-benefit test. The potential for such investments has a chilling effect on private investment.

156. There is some evidence that we have already reached that point in the NEM. In March 2017 the government of South Australia asserted that "the national energy market is failing"[79] and announced a package of measures, including a plan for the South Australian government to "build its own gas power plant", and introducing measures to require "more locally generated, cleaner, secure energy to be used in South Australia". In addition, the South Australian government announced that it will "legislate to give the Energy Minister direction over the market so South Australia's best interests always come first if there is an electricity shortfall."

157. A few days later the Prime Minister announced that a feasibility study would be undertaken to carry out a massive upgrade to an existing pumped hydro facility located in the Snowy Mountains. Gilbert and Tobin (2017) comment on this as follows:

> *"Recent events indicate that politicians may no longer be prepared to wait for, or trust, the NEM market mechanisms to incentivise sufficient investment in conventional, synchronised capacity to support system security … Politicians certainly do not appear content to wait for coherent policy reform recommendations from the Finkel Review or reviews being undertaken by AEMO and AEMC.*
>
> *Worringly, instead both Federal and State Governments have over recent weeks resorted to announcing direct investment in state-owned generation and storage, reversing a trend of 20 years in liberalising energy markets. This kind of direct government intervention appears to us only likely to displace private capacity. Indeed, since that announcement, AGL has indicated that it intends to revisit its energy investment blueprint for South Australia in light of policy uncertainty and, it may be assumed, the risk of competing with public funding".*[80]

158. The recent announcement by Australian state and federal governments may not yet undermine private investment. It is possible that the SA government's new gas power plant will only operate at times when the market price is at the price cap. It is possible that the proposed pumped hydro facility will not pass a feasibility test, or will turn out to be profitable on a purely commercial basis. Yet, on the surface, this appears optimistic. An outside observer may well conclude that confidence in the market has been already

[79] SA Government: ourenergyplan.sa.gov.au.

[80] Gilbert and Tobin (2017), page 46.

lost, that at least some governments are prepared to intervene in the market, and that local political considerations will be placed in tension with national market objectives.[81]

159. There is another factor which may contribute to a lack of confidence in the sector. That factor is the sheer pace of change. It is not yet clear that the electricity industry can adjust sufficiently in a timely manner.

160. In the normal course of events a regulatory framework should be stable and consistent to allow market participants to make needed sunk investments without adverse surprises. However, at the same time, no regulatory framework can be completely locked in or ossified. Some adjustment to new conditions over time is essential.

161. The Australian electricity market has a well-defined process for making changes from time to time, through a procedure for making amendments to the Rules. This process is overseen by the Australian Energy Markets Commission. Over the years dozens of Rule changes have been approved by the AEMC. This process allows for progressive, minor improvements to the regulatory framework over time.

162. But, arguably the electricity sector now faces one of its largest challenges since the National Electricity Market was created in 1998 (some say one of the largest challenges since the electricity grids were created). There is an argument that the NEM now requires not just minor tinkering, but a concerted leap forward – a “NEM 2.0”. It is not clear that the existing mechanisms can deliver a major change in a timely manner. A major change in the market would likely require a carefully designed, well-resourced policy development process including representatives from the industry, and seeking expert intellectual input.[82]

163. Electricity policy in Australia is a state, rather than federal, responsibility. The AEMC therefore reports to a body comprising representatives of the Australian states, known as the Council of Australian Governments Energy Council (COAG EC). However, experience has shown that state interests are seldom aligned. Some states retain substantial state ownership in electricity generation and/or network businesses. These states have a financial interest in protecting the revenue stream of their assets. Some states are heavily reliant on coal-fired generation, while others have large amounts of renewable generation.

164. Equally importantly, experience has shown that the different political composition of the state and federal governments has also proven to be a source of disagreement and uncertainty. In recent years the right-of-centre parties favouring more development of coal resources, while the left-of centre governments have tended to favour subsidies for renewable sources. These differences of opinion mean that truly concerted action at the COAG EC level is difficult. In addition, concern has been expressed about duplicating

[81] Going even further, Professor John Quiggen has argued for renationalisation of the sector. Quiggen (2017). Gilbert and Tobin (2017) observe: “A consequence of the politicisation of energy policy appears to be the dismantling of any coherent and integrated approach towards a national energy policy. As a case in point, the recent South Australian ‘Our SA Energy Plan’ is unabashedly parochial and explicitly rejects the operation or benefits of the NEM for South Australia. This trend is deeply regrettable”.

[82] The AEMC has stated: “As the Australian energy market becomes more dynamic with new technologies, emissions policy and consumers increasingly driving market developments, it is more important than ever that the governance arrangements are clearly understood, consistently applied, and receive a revitalised commitment from all parties in order to support timely and effective market development”. AEMC (2017b).

roles and processes between the Energy Council and the AEMC. [83] The AEMC has written:

> *"In light of the unprecedented pace of change in the energy sector, the ability of the governance framework to deliver successful reform relies on the Energy Council clearly defining a set of focussed priorities for the energy sector, and communication these to all parties. Effective and active leadership by the Energy Council in setting a strategic direction for the sector is critical if stakeholders are to unite behind a common set of priorities, or seek changes where they believe the priorities are not appropriate. ... Given the time-critical nature of energy market reform, it is imperative that the development of a strategic direction for the energy sector is supported by a robust framework and not frustrated by duplicative, time-consuming processes and delays in decision-making".*

165. Slow policy development processes may not be much of a problem in some industries. However, the electricity industry is particularly vulnerable. Somehow "we must execute a rapid transformation without compromising a delicate balance."[84] It remains to be seen whether an inability of the regulatory institutions to cope with the required change will contribute to an erosion of confidence in the electricity sector.

4. Conclusion

166. The electricity sector around the world is undergoing a fundamental transformation. This is due to both radical and incremental innovation. In general, such innovation is to be welcomed – it introduces new choices for consumers, as well as lowering the cost, while improving the reliability and environmental outcomes. There is increasing excitement in some sectors that consumers are entering a new age of choice and control over their electricity usage.

167. However, innovation requires a flexible and resilient regulatory framework. Major reforms in Australia in the 1990s introduced competition and structural separation into the electricity sector, establishing a strong foundation which has performed effectively over the last two decades. However the new innovations primarily involve connections to the distribution network. The distribution sector was largely untouched by the previous reforms in the 1990s. It seems likely that a major new concerted effort will be required to further extend the reform principles of the 1990s down to the distribution network level, including effective dynamic pricing of distribution networks, structural separation of networks and competitive businesses, and mechanisms for the coordination of private and regulated network investment.

[83] Australia's market operator, AEMO, has also expressed explicit concerns about delays in the policy-making process: "The NEM governance framework has a hierarchy of regulatory levels including legislation, Rules, Reliability Panel, industry procedures and operational systems. Some changes can take well over 6 months for each of a number of layers to serially make assessment. Once decisions are made, upwards of a year might then be required to implement changes, and transition periods are also required in some cases. Changes can therefore take many years from proposal to delivery. The current arrangement is therefore not sufficiently responsive or forward-looking to meet the needs of the paradigm shifts the NEM and its participants need to embrace". AEMO (2017b), page 4.

[84] John Bradley, ENA, speech on 16 October 2016

168. As in many sectors, success of these reforms will require on-going investment by end-customers and entrepreneurs. That investment requires confidence in the market, the regulatory frameworks, and the governance institutions. Unfortunately, the electricity sector is relatively politically sensitive. Even at the best of times, there are features of energy-only electricity markets which make them susceptible to political intervention. The electricity industry in Australia has been placed under further pressure due to a lack of consistent policy towards greenhouse gas abatement, rapid on-going investment in wind and solar generation, and a rapid rise in the wholesale gas price. In this environment, it is not clear that governments and governing institutions will be able to make needed long-term reforms in the market institutions and regulatory frameworks in a timely manner. These are indeed interesting times.

References

AEMC (2016), "Distribution Market Model: Approach Paper", 1 December 2016

AEMC (2017a), "2017 Energy sector strategic priorities review: Approach Paper", 19 April 2017

AEMC (2017b), "AEMC submission to the Independent Review into the Future Security of the National Electricity Market", 3 March 2017

AEMO (2010), "An Introduction to Australia's National Electricity Market", July 2010

AEMO (2017a), "Black System South Australia", March 2017

AEMO (2017b), "Submission to the AEMC System Security Market Frameworks Review Interim Report", 21 February 2017

BAEconomics (2017), "Implications of high wind penetration in the NEM", 13 February 2017.

Ben-David, Ron (2015), "If the retail energy market is competitive then is Lara Bingle a Russian cosmonaut?", presentation to the NEM Future Forum 2015 (Ron Ben-David is the chair of the Essential Services Commission of Victoria).

Biggar, Darryl, (2011), "The Theory and Practice of the Exercise of Market Power in the Australian National Electricity Market", 26 April 2011

Biggar, Darryl and Mohammad Hesamzadeh (2015), *The Economics of Electricity Markets*, Wiley

Biggar, Darryl and Andrew Reeves (2016), "Network pricing for the prosumer future: Demand-based tariffs or Locational Marginal Pricing?", chapter 13 in Sioshansi, F., ed., *Future of Utilities, Utilities of the Future,* Academic Press

Biggar, Darryl and Joe Dimasi (2017), "Public Policy Issues Associated with Feed-In Tariffs and Net Metering: An Australian Perspective", chapter 10 in Sioshansi, F., ed., *Innovation and Disruption at the Grid's Edge,* Academic Press

CEPA (2016), "Future Regulatory Options for Electricity Networks", Report prepared for ENA and CSIRO, 3 August 2016

Cicchetti, Charles (2016), "Residential Demand Charges: Bad Choice", *Public Utilities Fortnightly*, December 2016

Commerce Commission (New Zealand) (2016), "Input methodologies review decisions: Topic Paper 3: The future impact of emerging technologies in the energy sector", 20 December 2016

Cornell, Steve, and Steve Kihm, (2015), "Electric Industry Structure and Regulatory Responses in a High Distributed Energy Resources Future", Berkely Lab, Future Electric Utility Regulation, Report No. 1, November 2015

Energeia (2016), "Roles and Incentives for Microgrids and Stand Alone Power Systems", October 2016

Energy Transitions Commission (2017), "Better energy, greater prosperity: Achievable pathways to low-carbon energy systems", April 2017

Gilbert and Tobin, (2017), "Wrestling with the Electricity Market Transformation", April 2017

Grattan Institute (2013), "Shock to the System: Dealing with falling electricity demand", December 2013

Grattan Institute (2017), "Is the Retail Electricity Market Failing Consumers?", 13 March 2017

Hindsberger, Marcus and Nilesh Modi (2016), "Renewable technologies in the NEM", presentation to API Summer School, 24 February 2016

Knieps, Günter, (2016), "The evolution of smart grids begs disaggregated nodal pricing", chapter 14 in Sioshansi, F., ed., *Future of Utilities, Utilities of the Future*, Academic Press

MIT Energy Initiative (2016), "Utility of the Future: An MIT Energy Initiative response to an industry in transition", 2016

Nelson, Tim (2016), "Why we need a new NEM: AGL", 25 August 2016

OECD, (2001), *Restructuring Public Utilities for Competition*, 2001

Productivity Commission (2013), "Electricity Network Regulatory Frameworks: Inquiry Report", 9 April 2013

Quiggen, John (2017), "Grid Renationalisation – a discussion paper", Flinders University, Australian Industrial Transformation Institute, February 2017

Riesz, Jenny and Ian MacGill (2013), "100% Renewables in Australia: Will a Capacity Market be Required", 2013

Small Consumer Groups (2016), "Networks and Batteries: What's best for consumers?", September 2016

St Vincent de Paul (2016), "the NEM: A hazy retail maze", December 2016

Synergies and Yarrow (2016), "Applying the Hilmer Principles on economic regulation to changing energy markets: A report prepared by Synergies Economic Consulting and George Yarrow for the Energy Networks Association", April 2016