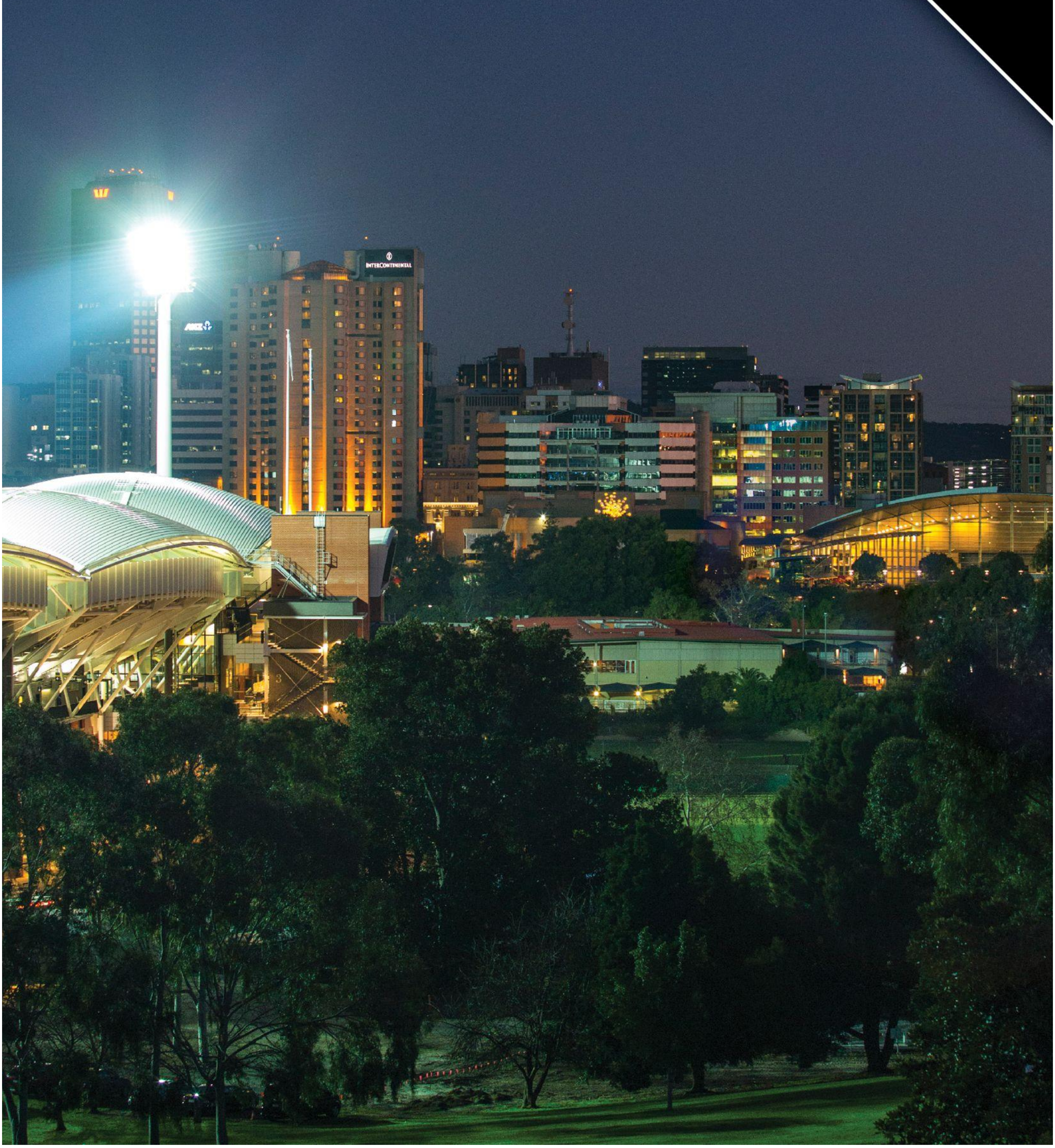
Attachment H.11

NERA_ Funding Projects that Provide Customer Benefits

03 July, 2015



Expert Report on Funding Projects that Provide Customer Benefits

Prepared for SA Power Networks, CitiPower and Powercor

23 June 2015

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1. Introduction

1.1. Scope of this Report

1. I have been commissioned to prepare this report for SA Power Networks, CitiPower Pty ("CitiPower") and Powercor Australia Ltd ("Powercor"). The context for this report is the review by the Australian Energy Regulator ("AER") of the revenues that Australian Distribution Network Service Providers ("DNSPs") are allowed to recover from customers, and in particular the AER's Preliminary Decision in respect of the determination of SA Power Networks' revenues for the 2015−20 regulatory control period.

2. This report, following my instructions in Appendix A, reviews the basis for the AER's decision not to allow any additional revenue for projects not meeting its narrow interpretation of the objectives, criteria and factors set out in the National Electricity Law ("NEL") and National Electricity Rules ("NER"). This report further examines the implications of these decisions.

1.2. My Expertise

3. I am a Senior Consultant of NERA UK Limited, which trades as NERA Economic Consulting ("NERA"). NERA is a global firm of experts dedicated to applying economic, finance, and quantitative principles to complex business and legal challenges.

4. I have been an employee of NERA UK Limited since 2006, and I am based in the London office. I hold an MPhil degree in Economics from the University of Cambridge and a BSc in Economics and Econometrics from the University of Bristol.

5. My role at NERA includes advising a range of clients, including SA Power Networks, CitiPower Pty and Powercor Australia Ltd, on matters related to the economic analysis of gas and electricity markets, and the regulation of electricity, gas and water network companies. In particular, I have advised a range of companies on matters related to the assessment of costs by regulators at periodic reviews of their regulatory controls.

6. My Curriculum Vitae, including a list of my project experience, is appended to this report as Appendix B.

1.3. Report Structure

7. The remainder of this report is structured as follows:

   (a) In Chapter 2, I summarise briefly the standards to which the AER adheres in making regulatory decisions. This chapter also summarises the key components of the AER's determination of regulatory controls for DNSPs, including opex and capex forecasts and incentive schemes.

   (b) In Chapter 3, I describe the AER's decision not to allow increased funding for investment projects in SA Power Networks' regulatory proposal, and the criteria against which the AER appraised these projects. I then assess from an economic perspective whether the AER's decision to disallow these projects was consistent with its relevant statutory objectives.

(c) In Chapter 4, I conclude that, by applying different assessment criteria in its evaluation of DNSPs' regulatory proposals, it could achieve an outcome that is both consistent with its statutory objectives and better aligned with the interests of consumers.

1.4. Declaration

8. I declare that I have read and understood the Federal Court's Practice Note CM7, entitled "*Expert Witnesses in Proceedings in the Federal Court of Australia*", and that I have prepared this report in accordance with those guidelines. I confirm that I have made all the inquiries that I believe are desirable and appropriate and that no matters of significance that I regard as relevant have, to my knowledge, been withheld from this report.

SIGNED Richard Dunn. ....

DATED 22nd June 2015 ....

2. Background

9. The AER regulates the revenues that gas and electricity network companies in Australia (apart from those in Western Australia and the Northern Territory) are allowed to recover from consumers. Within the six states and territories where the AER has jurisdiction, there are thirteen DNSPs which own the electricity distribution infrastructure. Each DNSP is a regional monopoly, some of which are state-owned and some of which are private entities.

10. The AER regulates each DNSP in five-year cycles. At periodic reviews it applies a combination of techniques to determine the amount of revenue each DNSP should be allowed to recover in the coming regulatory period. The AER is in the process of setting the allowed revenue of SA Power Networks, together with the Queensland (QLD) DNSPs, for the regulatory control period running from July 2015 to June 2020. The AER published its Preliminary Decisions for these DNSPs on 30 April 2015. At the same time, the AER published its Final Decisions on the New South Wales (NSW) and Australian Capital Territory (ACT) DNSPs' 2014-19 regulatory proposals. The AER will publish its Preliminary Decisions of allowed revenues for the Victorian DNSPs (including CitiPower and Powercor) in October 2015.

2.1. Opex Decision

11. There are several components of the AER's decision that affect a DNSP's allowed revenue. In this section I focus on the component of allowed revenue that the AER determines in order to cover future operational expenditure, or "opex". Broadly speaking, the AER follows three main steps in setting the opex allowance for a DNSP:

    i. The AER selects a "base year" (typically the second or third to last year of the preceding control period[1]) and assesses whether opex in this year reasonably reflects the "opex criteria" specified by NER.[2] As part of this step, the AER compares the costs of the thirteen DNSPs (including those for which the AER is not in the process of setting allowed revenues) through a process called "benchmarking". Through this benchmarking of DNSPs' opex, the AER estimates the level of opex it deems "efficient" in a base year, which differs for each company because the benchmarking controls for some differences between DNSPs, such as the size of their respective networks.

    ii. The AER then determines the rate at which it expects DNSPs' efficient operating expenditure to change between this base year and the end of the upcoming control period. The AER considers that efficient costs may change over time due to changes in the "outputs" companies deliver, such as growth in demand or the number of customers they serve, changes in the prices of the factor inputs DNSPs purchase in order to run their businesses, such as labour, and changes in productivity. The AER sets allowed rates of change for all three factors, which combine to determine the AER's allowed "rate of change" in operating expenditure.

[1] AER (2014): *SA Power Networks draft decision – Attachment 7: Operating expenditure*, Page 16-17.

[2] NER, clause 6.5.6(c).

iii. The AER then adjusts projected operating expenditure to account for any other forecast changes in cost over the upcoming control period. These adjustments are referred to as "step changes" in operating expenditure.

2.2. Capex Decision

12. The AER's capex decision is conducted using a more disaggregated approach. After deciding that a DNSP's regulatory proposal is not satisfactory, the AER conducts a line-by-line examination of the expenditures proposed against each sub-category of capex (eg. augmentation capex or replacement capex), allowing or disallowing some or all of the DNSP's proposed capital expenditures. For example, in its Preliminary Decision for SA Power Networks, the AER allowed $27 million of augmentation capex to maintain current levels of network reliability, but did not allow a further $29.4 million to improve network reliability, primarily during major weather events.[3]

2.3. Incentive Schemes

13. The AER's Preliminary Decision in respect of SA Power Networks includes four incentive schemes on top of the opex and capex allowances: the Efficiency Benefit Sharing Scheme ("EBSS"),[4] the Capital Expenditure Sharing Scheme ("CESS"),[5] the Service Target Performance Incentive Scheme ("STPIS")[6] and the Demand Management Incentive Scheme ("DMIS").[7]

14. The EBSS and CESS expose DNSPs to some share of the costs associated with overspends compared to the AER's allowances for opex and capex respectively, and allow them to retain the same share of underspends.[8] Given DNSPs are exposed to approximately the same share of overspends and underspends for both capex and opex, they should have little incentive to redirect expenditure from opex to capex (or vice versa), except where they can reduce their total costs by doing so.

15. The STPIS rewards or penalises DNSPs for exceeding or falling short of three performance targets: the System Average Interruption Duration Index ("SAIDI"), the System Average Interruption Frequency Index ("SAIFI") and performance in answering telephone enquiries. The SAIDI and SAIFI targets and incentive rates vary based on circuit type (Central Business District, urban, rural short and rural long). The target for answering telephone enquiries is

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3 AER (2015), Attachment 6, Table B-1.

4 AER (2015), Attachment 9.

5 AER (2015), Attachment 10.

6 AER (2015), Attachment 11.

7 AER (2015), Attachment 12.

8 The CESS sharing factor is explicitly defined as 30%, so DNSPs bear 30% of the cost of any capex overspends and retain 30% of the benefit of capex underspends. The EBSS sharing factor is implicitly defined to be approximately 30%, though that sharing factor may vary from 30% if DNSPs discount future cash flows at a rate that differs from the AER's determination of the Wighted Average Cost of Capital ("WACC").

defined as the proportion of telephone calls that a DNSP answers within 30 seconds (set at 67.8% in the SA Power Networks Preliminary Decision[9]).

16. Finally, the DMIS incentivises DNSPs "*to investigate and conduct broad-based and/or peak demand management projects*".[10] The DMIS bears little relevance to the content of this expert report, so I do not discuss it further.

2.4. The AER's Legal Obligations

17. In making a decision regarding DNSPs' regulatory controls, the AER is required to adhere to a range of obligations placed on it through the NEL and the NER. In particular, the NEL requires it to set regulatory controls "*in a manner that will or is likely to contribute to the achievement of the national electricity objective*" ("NEO").[11] The national electricity objective is as follows:[12]

> *"The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—*
>
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
>
> *(b) the reliability, safety and security of the national electricity system."*

18. When "*exercising a discretion*" such as in setting revenue controls for DNSPs, the AER "*must take into account the revenue and pricing principles*",[13] including the following principles:[14]

> *"(2) A regulated network service provider should be provided with a reasonable opportunity to recover **at least** the efficient costs the operator incurs in—*
>
> *(c) providing direct control network services; and*
>
> *(d) complying with a regulatory obligation or requirement or making a regulatory payment.*
>
> *(3) A regulated network service provider should be provided with **effective incentives in order to promote economic efficiency** with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—*

9 AER (2015), Attachment 11, page 15.

10 AER (2015), Attachment 12, page 6.

11 National Electricity (South Australia) Act 1996, para. 16(1), page 44.

12 National Electricity (South Australia) Act 1996, para. 7, page 38.

13 National Electricity (South Australia) Act 1996, para. 16(2), page 44. Emphasis added.

14 National Electricity (South Australia) Act 1996, para. 7A, page 38. Emphasis added.

> *(a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and*
>
> *(b) the efficient provision of electricity network services; and*
>
> *(c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services."*

19. According to the NER, a DNSP's opex or capex proposal "*must include the total forecast operating expenditure for the relevant regulatory control period which the* [DNSP] *considers is required in order to achieve each of the following (the operating expenditure objectives)*":[15]

> "*(iii) maintain the quality, reliability and security of supply of standard control services; and*
>
> *(iv) maintain the reliability and security of the distribution system through the supply of standard control services*."

20. The opex and capex *criteria* are the basis by which the AER decides whether to accept an opex or capex proposal. If the AER is satisfied that a DNSP's proposal meets the criteria, it "*must accept the forecast of required operating expenditure*". If the AER is not satisfied that the proposal meets the criteria, it "*must not accept the forecast of required operating expenditure*".[16] The criteria are that the proposal reflect the following: [17]

> "*(1) the efficient costs of achieving the operating expenditure objectives; and*
>
> *(2) the costs that a prudent operator would require to achieve the operating expenditure objectives; and*
>
> *(3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.*"

21. There are several factors which the AER "*must have regard to*" in determining whether it is satisfied that a proposal meets the opex and capex criteria. These are the opex and capex *factors* and include the following:[18]

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[15] AEMC: *National Electricity Rules,* Clauses 6.5.6 (a) and 6.5.7 (a). Note that I have quoted Clause 6.5.6 (a), which relates to operating expenditure. Clause 6.5.7 (a) is identical except that references to operating expenditure are instead references to capital expenditure.

[16] AEMC: *National Electricity Rules,* Clause 6.5.6 (c)-(d) and Clause 6.5.7 (c)-(d). Note that I have quoted Clause 6.5.6, which relates to operating expenditure. Clause 6.5.7 is identical except that references to operating expenditure are instead references to capital expenditure.

[17] AEMC: *National Electricity Rules,* Clause 6.5.6 (c) and Clause 6.5.7 (c). Note that I have quoted Clause 6.5.6 (c), which relates to operating expenditure. Clause 6.5.7 (c) is identical except that references to operating expenditure are instead references to capital expenditure.

[18] AEMC: *National Electricity Rules,* Clause 6.5.6 (e) and Clause 6.5.7 (e). Note that I have quoted Clause 6.5.6 (e), which relates to operating expenditure. Clause 6.5.7 (e) is identical except that references to operating expenditure are instead references to capital expenditure. Emphasis added.

> "*(5A) the extent to which the operating expenditure forecast includes expenditure to address* ***the concerns of electricity consumers*** *as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers.*
>
> *(8) whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider*."

22. The above set of legal obligations placed on the AER impose a range of constraints on its decisions over whether or not to allow funding for particular projects aimed at delivering benefits to consumers. First, the NEL clearly makes economic efficiency a priority in regulating DNSPs.[19] Second, whilst the NER requires the AER to accept a proposal that satisfies the opex and capex criteria and reject one that does not, it leaves the AER with discretion in assessing whether a proposal satisfies the criteria. Finally, the NER explicitly lists "*the concerns of electricity consumers*" as a factor the AER must have regard to in making that assessment.

23. Having set out the provisions in the NEL and NER that are relevant to the AER's assessment of DNSPs' regulatory proposals, in the following chapter I assess the extent to which the AER has followed these provisions in making its opex and capex decisions in its Preliminary Decision of the 2015-20 regulatory control period for SA Power Networks.

[19] I define the term "economic efficiency" below in Chapter 3.

3. Projects Providing Customer Benefits

24. In accordance with my instructions, in this chapter I consider whether the AER's Preliminary Decision in respect of SA Power Networks' regulatory proposal meets its statutory objectives, with particular focus on the AER's assessment of projects which provide customer benefits but for which the AER has not allowed increases in funding.

25. In Section 3.1, I describe a series of programmes included in SA Power Networks' regulatory proposal aimed at providing consumer benefits, but for which the AER has not allowed increases in funding. In Section 3.2, I define the concept of economic efficiency, which, as I note above, the AER is required to consider in making its determinations of revenue allowances. In Section 3.3, I evaluate the extent to which the AER's approach is likely to achieve economically efficient investments. In Sections 3.4 and 3.5, I assess whether the AER's incentive mechanisms, namely the EBSS, CESS and STPIS, as well as the possible existence of other sources of funding for DNSPs' investment programmes, change the conclusions I reach in Section 3.3.

3.1. Projects in SA Power Networks' Regulatory Proposal Delivering Consumer Benefits

26. In its regulatory proposal, SA Power Networks proposed several opex and capex projects which, according to its regulatory proposal, will deliver customer benefits, but for which the AER did not allow funding increases. In the following paragraphs, I describe some of these projects, along with the AER's specific reasons for not allowing funding increases.

3.1.1. Proposed improvements to the vegetation management programme

27. SA Power Networks proposed a $31.9 million opex increase (in total over the regulatory control period) to improve its vegetation management programme. In particular, it proposed to: increase the frequency of its tree-trimming cycle in non-bushfire risk areas from three years to two years; remove trees from 2.5% of infringing spans in bushfire risk areas; implement a tree removal and replacement programme for inappropriate, fast growing or large trees in cities and towns; improve the visual amenity in metropolitan regions by hiring qualified arborists; and improve community engagement around its vegetation management. SA Power Networks justified this proposal, in part, by presenting evidence from its customer engagement programme which it considers demonstrates that customers' willingness-to-pay for these schemes exceeds the cost of implementation.[20]

28. However, the AER did not allow this additional expenditure. It stated that "*we determine the required funding for SA Power Networks to achieve its regulatory obligations. Where there are no regulatory obligations, we determine funding that would maintain the reliability, safety and quality of supply. Improved* [visual] *amenity is not an objective we are directed to consider when determining SA Power Networks' funding requirements*".[21] It further argued that communities could pay separately for improved visual amenity and that the tree removal

[20] SA Power Networks (2015): *Regulatory Proposal – Attachment 21.13: Opex Step Changes*, pages 145-171.

[21] AER (2015), Attachment 7, page 98.

and replacement programmes proposed by SA Power Networks would deliver efficiencies that the AER considers to be covered through the EBSS.[22]

3.1.2. Proposed improvements in safety and customer service

29. SA Power Networks also proposed a $4.3 million opex increase for customer service programmes including an education programme to help customers understand who SA Power Networks is, thereby improving trust and communication between SA Power Networks and its customers, a communications plan to inform customers of new self-service options, and the establishment of a new customer service team. SA Power Networks noted that its customer engagement programme indicated support for these programmes, which are intended to benefit consumers through enhanced quality of customer service.[23]

30. Further, the company proposed a $5.4 million opex increase for customer safety improvements. This broke down into a summer media campaign to educate customers about bushfire risk with respect to power lines and outages; a media campaign to educate customers about the dangers and implications of outages in extreme weather events and drought; and an education programme for farmers and sailors regarding the risk of equipment coming into contact with power lines. SA Power Networks noted that its customer engagement programme indicated support for these programmes, which are intended to benefit consumers through increased safety and the prevention of bushfires.[24]

31. The AER did not allow increases in funding for the customer service or safety programmes. In its view, these programmes are discretionary and should be managed within SA Power Networks' existing budget. It also reiterated that it only allowed funding increases when necessary to "*meet or manage expected demand [or] maintain the reliability, safety and quality of supply of the service*".[25] With respect to the safety programmes, the AER argued that, although "*public safety should and would always be a priority for SA Power Networks*", the AER sees no reason why safety expenditure should increase from its present level.[26]

3.1.3. Improved protection against severe weather events

32. SA Power Networks also proposed a $17.0 million capex increase to harden the network against severe weather events. It noted that its customer engagement programme indicated support for this programme, which would improve network reliability, primarily during major weather events. SA Power Networks argued that it would not be remunerated for this expenditure through the STPIS because investments to improve resilience may reduce the likelihood of some days being classified as Major Event Days ("MEDs"),[27] and the AER excludes MEDs from the calculation of DNSPs' SAIDI and SAIFI indices. By improving

[22] AER (2015), Attachment 7, pages 99-100.

[23] SA Power Networks (2015), Attachment 21.13, pages 166-188.

[24] SA Power Networks (2015), Attachment 21.13, pages 189-204.

[25] AER (2015), Attachment 7, page 103.

[26] AER (2015), Attachment 7, page 103.

[27] MEDS are days of exceptionally severe weather that trigger particularly high levels of interruptions.

network performance during extreme weather events, investments to improve resilience may therefore cause the AER to include more of DNSPs' outages in its calculation of the SAIDI and SAIFI indices. This, in turn, would reduce DNSPs' revenue, in effect penalising improvements in resilience.[28]

33. Furthermore, the STPIS does not provide any incentive to improve resilience during MEDs, because any interruptions during MEDs are excluded from DNSPs' SAIDI and SAIFI indices.

34. The AER did not allow SA Power Networks increased funding for its proposed improvements in resilience because it has introduced a new methodology for determining MEDs, which would reduce the number of MEDs excluded from the STPIS.[29] However, the AER has not proposed entirely to eliminate the exclusion of some MEDs from the STPIS calculations, and so DNSPs will still not capture the full benefit of improvements in resilience to extreme weather events.

3.2. Defining Economic Efficiency in Regulatory Control Settlements

35. As discussed in the previous chapter, the NEL states that a DNSP should have "*effective incentives to promote economic efficiency*", while the opex and capex criteria refer to "*the efficient costs of achieving the operating expenditure objectives*".[30] There are several ways one can define the terms "efficiency" and "economic efficiency".

36. In the context of regulated network companies, a company is often described as "efficient" if the regulator considers that it is delivering the services required of it at the lowest cost that it can reasonably achieve. In the case of Australian DNSPs, for instance, the AER assesses companies' relative efficiency through a process of benchmarking to identify efficient base year costs, as described above in Section 2.1. However, this definition of efficiency, which economists would generally describe as "productive efficiency,[31] where a firm uses the cheapest mix of inputs it can in order to produce a given amount of output, is just one aspect of what economists term "economic efficiency".

37. Economic efficiency also encompasses the concept of "Pareto efficiency", sometimes referred to as "allocative efficiency",[32] which means that one could not reallocate resources to make one party better off without making another party worse off. In essence, this criterion requires that producers increase their output up to the point where the cost of producing more output becomes larger than consumers' willingness to pay for it. That is, firms operating in a market should produce as much output as possible, as long as consumers value that output at a price higher than the marginal cost of production.

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[28] AER (2015), Attachment 6, page 78.

[29] SA Power Networks (2015): *Regulatory Proposal*, pages 95-101.

AER (2015), Attachment 6, pages 78-79.

[30] AEMC: *National Electricity Rules*, Clause 6.5.6 (c) and Clause 6.5.7 (c). Note that I have quoted Clause 6.5.6 (c), which relates to operating expenditure. Clause 6.5.7 (c) is identical except that references to operating expenditure are instead references to capital expenditure.

[31] Harold Fried et al (1993): *The Measurement of Productive Efficiency*, page 10.

[32] David Kreps (1990): *A Course in Microeconomic Theory*, page 153.

38. Finally, there is a time component to efficiency. Basic microeconomic theory tends to focus on static efficiency, but this is an incomplete definition. Ensuring economic efficiency requires, in practice, consideration of "dynamic efficiency", such that present consumers should not be made better off by harming future consumers, and vice versa.[33] In essence, this requires application of the concept of economic efficiency on a forward-looking basis.

3.3. The Economic Consequences of the AER's Decision

39. As the examples in Section 3.1 illustrate, the AER repeatedly emphasises its narrow reading of the NEL and NER in its Preliminary Decision of SA Power Networks' revenue control, and states that it does not approve increases in expenditure which are not required "*to achieve a service provider's regulatory obligations, meet or manage expected demand, or to maintain the reliability, safety and quality of supply of the service*".[34] The AER ignores any benefits outside of those narrow criteria, and as I describe above, disallows DNSPs' proposed projects that provide other types of benefits to consumers.

40. For example, SA Power Networks justifies its proposal to increase the frequency of its tree cutting cycle using evidence on consumers' valuation of the resulting improvements derived from a process of engagement with consumers in South Australia.[35] In this case, the AER states that "*improved amenity is not an objective we are directed to consider when determining SA Power Networks' funding requirements*".[36]

41. The AER's decision not to approve increases in expenditure to fund projects that provide broader benefits to consumers, besides those identified explicitly in the NEL and NER, is not economically efficient. In essence, if consumers are willing to pay for the additional outputs the DNSP has proposed at a price greater than or equal to the cost of provision, then it is inconsistent with the criterion of economic efficiency, as defined above and specified as a capex and opex factor, that the DNSP should not be provided with sufficient funding to deliver them.

42. In other words, the DNSP wants to provide better service to its customers, and customers want to buy that improvement in service quality. The AER's proposed approach prevents this potential "transaction" between the DNSP and consumers, and ultimately it is consumers that lose out as a result. Such an outcome therefore appears contrary to the AER's overriding objective in the NEL to "*promote efficient investment in, and efficient operation and use of, electricity services for the long term interest of consumers of electricity*".[37] It further undermines SA Power Networks' incentive to seek its customers' views and respond accordingly, since the AER has ignored the evidence from customer engagement put forward by SA Power Networks in its regulatory proposal.

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[33] Daron Acemoglu (2009): *Introduction to Modern Economic Growth,* page 338.

[34] AER (2015): *SA Power Networks' determination 2015-20, Attachment 7 – Operating expenditure*, page 76.

[35] AER (2015), Attachment 7, page 97.

[36] AER (2015), Attachment 7, page 98.

[37] National Electricity (South Australia) Act 1996, para. 16(1), page 44.

3.4. Funding Provided through the AER's Incentive Schemes

43. The AER has declined to allow increases in revenue to cover the costs of some schemes proposed by SA Power Networks on the grounds that they are intended to reduce future costs, and that the EBSS and CESS incentive schemes already provide adequate incentives to motivate the company to deliver them to the extent that it is efficient for it to undertake such schemes. For example, the AER did not allow an increase in funding for an SA Power Networks' tree removal programme which SA Power Networks describes as "*the most appropriate solution over the long-term as regular and ongoing clearance is required for compliance*".[38] The AER did not approve this increase because "*we do not approve increases in funding for programs that we expect to deliver efficiencies. We expect a service provider to weigh up the cost and benefits before deciding to invest in a project or program*".[39]

44. However, while the EBSS and CESS provide DNSPs with an efficient incentive to invest (through additional capex or temporary increases in opex) to reduce future costs, they do not provide an incentive for DNSPs' to invest efficiently to deliver customer benefits.

45. The EBSS and CESS ensure that DNSPs bear a 30% share of increases or decreases in expenditure compared to their allowances, with the remaining 70% passed through to consumers. As a consequence, DNSPs' economic incentive to reduce future costs is aligned with the interest of consumers, because DNSPs retain the same share of benefits from reduced future costs as they bear in upfront implementation costs. Hence, DNSPs have an efficient incentive to invest when the sole benefit of projects is reduction in future costs.

46. However, when a DNSP's investment initiatives provide a wider range of benefits besides reductions in future expenditure, such as in the form of consumer benefits, the EBSS and CESS no longer give them efficient investment incentives because these benefits are not captured by the DNSP.

47. Take, for instance, SA Power Networks' plan to remove and replace inappropriate, large or fast-growing trees. The AER does not allow an increase in revenue in part because it should ultimately yield efficiency savings, relative to constantly trimming fast-growing trees. Therefore, SA Power Networks will benefit through the EBSS and will undertake the programme if the projected savings outweigh the costs (in present value terms). However, we understand from SA Power Networks that the share of efficiency savings retained through the EBSS and CESS do not justify the implementation costs. The project is only economically justified when it accounts for the non-monetary benefits of the programme, such as improved visual amenity and safety.

48. In this situation, therefore, SA Power Networks would require an increase in revenue specifically provided to cover the costs of this programme, or else it will have inadequate incentives to deliver it. Consequently, any associated customer benefits will not be realised.

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[38] SA Power Networks, Attachment 21.13, page 152.

[39] AER (2015), Attachment 7, page 100.

49. DNSPs do retain a share of the consumer benefits from reduced interruptions provided by investment projects through the STPIS.[40] However, insofar as there are customer benefits associated with programmes that go beyond improvements in reliability, the STPIS will not capture them and will not reward DNSPs for them. Moreover, as discussed in Section 3.1.3 above, the STPIS does not provide an incentive to reduce the customer impact of severe weather events, so SA Power Networks' proposal to harden its network against such events may not be fully remunerated through the STPIS.

50. Overall, therefore, the AER's incentive schemes (the EBSS, CESS and STPIS) do not resolve the problem identified in this chapter, namely that DNSPs have an insufficient incentive to carry out projects that are in the public interest. The AER's failure to address this problem is inconsistent with the goal of maximising economic efficiency, and is therefore inconsistent with the AER's statutory objectives.

3.5. Other Funding Mechanisms

51. Another reason offered by the AER for not allowing funding increases for the types of schemes described in Section 3.1 is that there may be other sources of funding available. For example, local councils and the Local Government Association of South Australia indicated support for SA Power Networks' tree cutting proposals. Noting this support, the AER stated that local councils are welcome to fund additional tree cutting out of their own budgets if they wish to do so.[41]

52. There is no clear reason, from the perspective of economic efficiency, why it would be better for local councils to fund such programmes through general taxation than for the utility to fund them through increases in revenue (that would need to be approved by the AER) recovered through electricity bills. Those individuals and businesses whose taxes fund councils' budgets are likely to overlap materially with electricity bill-payers, so the funding will come from similar sources under both approaches. And councils are not necessarily well-placed to negotiate with DNSPs. Instead, the AER has expert understanding of the regulatory and commercial arrangements in which DNSPs operate, and can agree on additions to DNSPs' revenues for enhanced outputs without incurring significant additional transaction costs, although it is of course reasonable for the AER to factor into its decision the impact of any known local council funding available to SA Power Networks.

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[40] AER (2015), Attachment 11, Table 11.2.

[41] AER (2015), Attachment 7, page 99.

4. Conclusion

53. The objective of the NEL is "*to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity*". The NER also identifies factors to which the AER must have regard in deciding whether to accept DNSPs' opex or capex proposals. As I explained in Section 2.4, one of those areas is the extent to which an operating or capital expenditure forecast "*includes expenditure to address the concerns of electricity consumers as identified by the* [DNSP] *in the course of its engagement with electricity consumers.*"

54. In its Preliminary Decision on SA Power Networks' regulatory proposal, the AER has chosen to take a very narrow view of the criteria for allowing increased opex and capex funding, which does not recognise the value that certain of the company's investments would provide for consumers. Thus, the criteria as applied by the AER in deciding whether to fund increased opex or capex does not promote efficient investment in electricity services, and is therefore not in the long-term interests of consumers of electricity.

55. In other words, the NER instructs the AER to have regard to areas of concern for electricity consumers. When the AER rejected all of SA Power Networks' consumer-driven initiatives on the basis that consumer benefits were not a legitimate justification for expenditure increases, it did not have regard for that requirement of the NER. On this basis I conclude that the AER is acting contrary to the objective of the NEL "*to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity.*"

56. Therefore, for the reasons discussed in this report, the projects that are economically efficient and thus should be conducted to further the consumer interest, but that the appraisal methodology followed by the AER would preclude, are those that fulfil the following two criteria:[42]

    a. The incremental costs of undertaking the project exceed the sum of (1) the future cost savings resulting from scheme and (2) the value of improved reliability (if any) captured through incentive payments to the DNSP through the STPIS. In other words, the DNSP does not have an incentive to undertake the projects; and

    b. The incremental costs of undertaking the project are less than the sum of (1) the future cost savings resulting from scheme and (2) the social value of improved reliability and any other consumer benefits, as indicated by customers' willingness to pay for such benefits. In other words, it is economically efficient (and in consumers' interests) for the DNSP to undertake the project.

[42] All costs and benefits should be assessed on a net present value basis.

Appendix A. Instructions

4 June 2015

Mr Richard Druce
NERA UK Limited
By email: Richard.Druce@nera.com

Dear Richard

Expert report on AER approach to funding of projects providing customer benefits

CitiPower Pty, Powercor Australia Ltd and SA Power Networks (**Businesses**) are electricity distribution network service providers (**DNSPs**) in the states of Victoria and South Australia in Australia, subject to economic regulation by the Australian Energy Regulator (**AER**) under the National Electricity Law (**NEL**) and National Electricity Rules (**NER**).

The AER is required to make distribution determinations in respect of regulatory proposals put forward by the Businesses, which determine the revenues that each of the Businesses should be allowed to recover in future regulatory control periods. SA Power Networks submitted a regulatory proposal for the 2015–16 to 2019–20 regulatory control period on 31 October 2015. CitiPower and Powercor Australia submitted regulatory proposals for the 2016 to 2020 regulatory control period on 30 April 2015. The AER made a preliminary decision regarding SA Power Networks' regulatory proposal on 30 April 2015 (**Preliminary Decision**). No decision has yet been made regarding CitiPower or Powercor Australia's regulatory proposals.

The Businesses would like to engage NERA UK Limited (**NERA**) to provide an expert report on the AER's approach to funding projects which provide customer benefits in its Preliminary Decision, which addresses the matters set out in the scope of work contained in this letter.

Preliminary Decision

The AER outlines its approach to assessing operating expenditure (**opex**) for projects which provide customer benefits in Appendix C to *Attachment 7 - Operating expenditure* of the Preliminary Decision (pages 7-73 to 7-76 and 7-97 to 7-102).
The specific projects are:

- Vegetation management
- Customer service
- Community safety

The AER outlines its approach to assessing capital expenditure (**capex**) for projects which provide customer benefits in Appendix B to *Attachment 6 – Capital expenditure* of the Preliminary Decision (pages 6-76 to 6-81). The specific projects are:

- Harden the network against storms
- Remote communities service improvement
- Outlier low reliability feeders

Requirements of the NEL and the NER

In performing or exercising economic regulatory functions or powers (including in making distribution determinations), section 16(1)(a) of the NEL provides that the AER must do so in a manner that will or is likely to contribute to the achievement of the national electricity objective (**NEO**). The NEO is set out in section 7 of the NEL as follows:

> The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

If the AER is making a reviewable regulatory decision (including a distribution determination) and there are two or more possible reviewable regulatory decisions that will or are likely to contribute to the achievement of the NEO, section 16(1)(d) of the NEL provides that the AER must make the decision it is satisfied will or is likely to contribute to the NEO to the greatest degree.

In addition, section 16(2) of the NEL provides that in exercising a discretion in making those parts of a distribution determination relating to direct control services, the AER take into account the revenue and pricing principles set out in section 7A of the NEL (**RPPs**).

Chapter 6 of the NER governs the economic regulation of distribution services and sets out the process by which distribution determinations are made. Clause 6.4.3 of the NER provides that the annual revenue requirement of DNSPs for each year of a regulatory control period must be determined using a building block approach, under which the building blocks include:

a. forecast opex for that year;

b. a return on capital for that year; and

c. indexation of the regulatory asset base.

During a regulatory control period, the regulatory asset base values (and thus the return on capital and indexation of the regulatory asset base building blocks) are increased during the regulatory control period by reference to allowed capex forecasts.

Clause 6.5.6(a) of the NER provides that a building block proposal must include the total forecast opex for the relevant regulatory control period which the DNSP considers is required in order to achieve each of the operating expenditure objectives (set out in that provision) (**opex objectives**).

Clause 6.5.6(c) provides that the AER must accept the forecast of required opex if it is satisfied that the total forecast opex for the regulatory control period reasonably reflects the following:

a. the efficient costs of achieving the opex objectives;

b. the costs that a prudent operator would require to achieve the opex objectives; and

c. a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives

(**opex criteria**).

In deciding whether it is so satisfied, the AER must have regard to the operating expenditure factors set out in clause 6.5.6(e) of the NER (**opex factors**). If the AER does not accept the proposed opex forecast, the AER must estimate the opex that the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors (see clause 6.12.1(4) of the NER).

Analogous provisions in respect of capex are set out in clauses 6.5.7 and 6.12.1(3) of the NER.

The NER provides for the AER to develop of a number of incentive schemes, including as follows:

a. Clause 6.5.8 of the NER requires the AER to develop an incentive scheme or schemes ('efficient benefit sharing scheme' (**EBSS**)) that provide(s) for a fair sharing between DNSPs and distribution network users of the efficiency gains (and losses) derived from the opex of a DNSP for regulatory control period being less than (or more than) the forecast opex accepted or substituted by the AER for that regulatory control period.

b. Clause 6.5.8A of the NER allows the AER to develop an incentive scheme that provides DNSPs with an incentive to undertake efficient capex during a regulatory control period ('capital expenditure sharing scheme' (**CESS**)).

c. Clause 6.6.2 of the NER requires the AER to develop an incentive scheme or schemes ('service target incentive scheme' (**STPIS**)) to provide incentives for DNSPs to maintain and improve performance.

In making a distribution determination, clause 6.12.1(9) of the NER requires the AER to determine how any applicable EBSS, CESS or STPIS is to apply to the DNSP. The AER outlines its preliminary decision regarding the application of the EBSS, CESS and STPIS to SA Power Networks in the 2015–16 to 2019–20 regulatory control period in Attachments 9, 10 and 11 to the Preliminary Decision respectively.

One of the opex factors to which the AER must have regard in assessing opex is whether the opex forecast is consistent with certain incentive scheme or schemes that apply to the DNSP, including the EBSS and STPIS (clause 6.5.6(e)(8) of the NER).

One of the capital expenditure factors to which the AER must have regard in assessing capex is whether the capex forecast is consistent with certain incentive scheme or schemes that apply to the DNSP, including the CESS and STPIS (clause 6.5.7(e)(8) of the NER).

Scope of work

We request that you prepare an expert report that addresses the following:

a. Does the AER's approach to assessing opex for projects which provide customer benefits in the Preliminary Decision result in opex forecasts required to achieve each of the opex criteria, having regard to the opex factors?

b. Does the AER's approach to assessing capex for projects which provide customer benefits in the Preliminary Decision result in capex forecasts required to achieve each of the capital expenditure criteria, having regard to the capital expenditure factors?

c. In assessing opex and capex for projects which provide customer benefits in the Preliminary Decision, has the AER done so in a manner that will or is likely to contribute to the NEO, taking into account the RPPs?

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Powercor Australia Ltd ABN 89 064 651 109 General Enquiries 13 22 06 www.powercor.com.au

In addressing the above questions, we request that you consider the AER's:

a. rationale for rejecting opex for projects that provide customer benefits on the basis that they can be funded through base year efficiency savings; and

b. rationale for rejecting opex and capex for projects that provide customer benefits on the basis that the project costs should be offset by future efficiency savings and applicable incentive schemes.

For the purposes of undertaking this work, the Businesses will provide you with a copy of the documents listed in Attachment A. A list of the documents the Businesses have provided to you, and any additional documents relied on by NERA in preparing the report, should be included in the report. A copy of any documents included in the list that were not provided to NERA by the Businesses should be provided to the Businesses with the report.

Expert witness

Included as Attachment B to this letter is a copy of *Practice Note CM7: Expert Witnesses in Proceedings in the Federal Court of Australia*, 4 June 2013. The Businesses request that your report complies with the requirements of Practice Note CM7, and that you certify in your report that you have complied with Practice Note CM7.

The Businesses request that you attach to the report a copy of this engagement letter and a copy of the CVs of the authors, which contain all qualifications and relevant experience.

Timing

The Businesses request that NERA produce its final report by no later than 12 June 2015.

Yours sincerely

Brent Cleeve

Brent Cleeve
General Manager Regulation
on behalf of CitiPower, Powercor Australia and SA Power Networks

Attachment A: Documents provided to NERA

AER, Preliminary Decision, SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital expenditure, April 2015

AER, Preliminary Decision, SA Power Networks determination 2015–16 to 2019–20, Attachment 7 – Operating expenditure, April 2015

SA Power Networks, Regulatory Proposal 2015/16 to 2019/20

SA Power Networks, Regulatory Proposal 2015/16 to 2019/20, Attachment 21.13 Opex Step Changes

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Attachment B: ***Practice Note CM7: Expert Witnesses in Proceedings in the Federal Court of Australia***

Appendix B. Curriculum Vitae

Richard Druce

Senior Consultant

NERA Economic Consulting
Marble Arch House
66 Seymour Street
London, W1H 5BT
United Kingdom
Tel: +44 20 7659 8540
Fax: +44 20 7659 8541
E-mail: richard.druce@nera.com
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Overview

Mr Druce advises clients, including utilities, regulators, governments and financial investors on matters related to the economic analysis of gas and electricity markets, and the regulation of gas and electricity network companies. In particular, he has advised a range of companies on matters related to the assessment of costs by regulators at periodic reviews of their price or revenue controls, including EDF Energy Networks, Wales and West Utilities, Thames Water, PowerNI, NIE Power Procurement Business, Fluxys, ENBW, and London Underground Limited.

Mr Druce holds an MPhil degree in Economics from St Catharine's College, Cambridge. He also holds a first class degree in Economics and Econometrics from the University of Bristol. Before joining NERA, he worked at the UK Office of Rail Regulation.

Qualifications

2005-2006	**ST CATHARINE'S COLLEGE, CAMBRIDGE** MPhil Economics
2002-2005	**UNIVERSITY OF BRISTOL** BSc Economics and Econometrics

Career Details

2006-Present	**NERA ECONOMIC CONSULTING** Senior Consultant (2012-), London Consultant (2009-12), London Analyst (2006-09), London
Summer 2004 & Summer 2005	**OFFICE OF RAIL REGULATION** Temporary Assistant Economist

Project Experience

2015

- For the UK Energy Networks Association (DCRP P2 Working Group), advising on potential changes to Engineering Recommendation P2/6, the design standard that governs the investments that British electricity distributors are obliged to make in their networks to ensure security of supply.
- For the UK Committee on Climate Change, in collaboration with Imperial College London, analysing the marginal system integration cost associated with the connection of increased volumes of intermittent and other low carbon generation technologies onto the British power system.
- For UK Power Networks (with SP Energy Networks, Electricity North West and Northern Power Grid), advice in the course of the appeal to the Competition and Markets Authority of Ofgem's "RIIO-ED1" price control decision by British Gas Trading Limited.
- For UK Power Networks, advice in the course of the appeal to the Competition and Markets Authority of Ofgem's "RIIO-ED1" price control decision by Northern Powergrid Limited.
- For a British distribution network operator, advice on the potential case for a CMA referral in the context of Ofgem's Final Determination from the RIIO-ED1 price control review. This project is being conducted in collaboration with Imperial College London and DNV GL.

2014

- For the British electricity Distribution Network Operators (DNO), through the Energy Networks Association, drafting a critique of Ofgem's Draft Determination of the allowance for Real Price Effects over the RIIO-ED1 control period, and forecasting inflation in cost indices using ARIMA methods.
- For Scottish Power Energy Networks (SPEN), in the context of the RIIO-ED1 price control review, providing a range of support related to Ofgem's assessment of efficient costs, including analysis of econometric benchmarking, real input price inflation, and regional and "special" factors.
- For UKPN, support in relation to the outlook for real input price inflation in the context of the RIIO-ED1 price control review.
- For the Singapore Gencos (Tuas Power, Pacific Light Power Corp, Senoko and PowerSeraya), preparing a review and critique of the Energy Market Authority of Singapore's Draft Determination of the Vesting Contract Level for 2015/16.
- For ElecLink, a proposed interconnector between Great Britain and France, designing the auction-based mechanism for allocating long-term capacity rights through an open season.
- For Thames Water, developing a "Special Factor" case as part of the Ofwat Price Review 2014 process, identifying and quantifying factors affecting the company's costs that are not allowed for in the Ofwat cost assessment benchmarking.

- For the Saudi Electric Company (SEC), advice on power sector restructuring issues in the context of the proposed divestment of shares in SEC's generation and distribution assets, and the introduction of more competitive power procurement arrangements, with a particular focus on the design of distribution network regulatory arrangements.
- For RWE npower (in collaboration with Imperial College London), preparing reports in the context of Project TransmiT to (1) compare the long-run marginal cost of transmission investment with the tariffs under alternative charging methodologies, (2) estimate the welfare effects of the WACM2 charging methodology using detailed market and transmission system simulation models, and (3) review an Ofgem consultation paper.
- For the Department of Environment, Food and Rural Affairs (Defra), conducting quality assurance of a Monte Carlo simulation model, and the econometric analysis used to calibrate input assumptions.

2013

- For Western Power Distribution, a UK electricity Distribution Network Operator (DNO), conducting financial risk modelling in the context of Ofgem's RIIO-ED1 price control review.
- For Scottish Power Energy Networks (SPEN), in the context of the RIIO-ED1 price control review, providing a range of support related to Ofgem's assessment of efficient costs, including analysis of econometric benchmarking, real input price inflation, and financial risk modelling.
- For the European Commission (in collaboration with Imperial College London and KEMA), advising on the regulatory, commercial and market arrangements required to efficiently integrate renewables into the European power system. This assignment covered wholesale market design, transmission and distribution grid access and charging arrangements, and renewables subsidy mechanisms.
- For RWE npower (in collaboration with Imperial College London), preparing reports in the context of Project TransmiT to (1) critique the impact assessment published by Ofgem following the Project TransmiT "Significant Code Review", and (2) estimate the welfare effects of the WACM2 charging methodology using detailed market and transmission system simulation models.
- For the Electricity and Cogeneration Regulatory Authority (ECRA) of Saudi Arabia, advising on various aspects of power market design, competition and regulatory issues, including detailed modelling of the KSA power system.
- For a confidential investor, performing regulatory due diligence for the London Array wind farm.
- For a confidential investor, valuation of UK onshore wind farms and a project to convert an existing coal-fired power station into a dedicated biomass generation facility.
- For a confidential client, providing economic analysis relating to changes in the costs of upstream oil and gas production.
- For a confidential investor, valuation of a portfolio of power generation capacity (coal-fired, gas-fired CCGTs, pumped storage and oil-fired peakers).

2012

- For Wessex Water (UK), conducting a ‘stated preference’ study to assess consumers’ willingness to pay for improvements to the quality of water supply and sewerage service using econometric modelling.
- For Bristol Water (UK), conducting a ‘stated preference’ study to assess consumers’ willingness to pay for improvements to the quality of water supply using econometric modelling.
- For the Regulation and Supervision Bureau (Abu Dhabi), advising on the development of cost reflective tariffs for electricity and water supply, including statistical analysis of consumption data to estimate representative consumption profiles using “quantile regression” techniques, and the development of a detailed water and power sector despatch model.
- For the Department of Environment, Food and Rural Affairs (Defra), conducting quality assurance of a Monte Carlo simulation model, and the econometric analysis used to calibrate input assumptions.
- For the UK Office of Rail Regulation (ORR), analysing the impact of an increase in rail freight access charges on the demand for coal from the Electricity Supply Industry using a model of the wholesale electricity market.
- For a major UK utility, reviewing Ofgem’s proposals to implement “mandatory auctions” for the sale of electricity generated by the “big 6” utilities operating in the British market.
- For The Department for Energy and Climate Change (DECC), providing analysis of the long-term “balancing challenge” driven by the integration of intermittent renewables and the electrification of the heat and transport sectors.
- For RWE npower (in collaboration with Imperial College London), review of Ofgem proposals to amend Transmission Network Use of System (TNUoS) charges following Project TransmiT to better reflect the costs imposed on the transmission system by intermittent renewable power generators.
- For the Omani Power and Water Procurement Company (OPWP), advising on contractual, regulatory and market issues associated with the renegotiation of power and water purchase agreements (PWPAs).
- For an Irish utility, providing an independent review of the company’s 5-year business plan (electricity generation, wholesale trading, renewables and retail businesses) in support of a potential refinancing.
- For a confidential investor, valuation of a portfolio of power generation capacity (coal-fired, gas-fired CCGTs, pumped storage and oil-fired peakers).

2011

- For a NW European gas trading company, providing economic advice regarding the appropriateness of the tariff charged for accessing a gas pipeline.

- For Power NI, providing regulatory advice and quantitative analysis (Monte Carlo simulation of cash balances) to estimate the margin required over the upcoming control period.
- For an Irish utility, providing an independent review of the company's 5-year business plan (electricity generation, wholesale trading, renewables and retail businesses) in support of a potential refinancing.
- For ScottishPower, modelling the impact of the UK government's Electricity Market Reform (EMR) proposals, including analysing the impact of the CO2 price floor and a targeted capacity mechanism.
- For RWE npower, in collaboration with Imperial College London, electricity market modelling work to compare the welfare effects of locational Transmission Network Use of System (TNUoS) charges with a uniform tariff.
- For a confidential investor, valuation of a portfolio of UK generation assets including gas and coal capacity, pumped storage and oil-fired peaking plant.
- For a confidential investor, valuation of UK gas-fired generators in support of a proposed transaction.
- For a confidential investor, conducting market due diligence for a proposed new nuclear power plant in the Bulgarian market, including long-term power price forecasting out to 2050.
- For NIE Energy Power Procurement Business, conducting bottom-up Monte Carlo modelling to assess the risks to which the company is exposed, and so estimate the margin required by the company through its price control.
- For NIE Energy Supply, advising on possible contract structures for the procurement of energy from renewable generators.

2010

- For a confidential investor, power price forecasting and market analysis in the South Korean power market, including detailed analysis of Asian and world gas markets with focus on the Asian LNG spot market.
- For the Ministry of Trade and Industry (Singapore), providing technical and market advise in the course of an appeal by the Singapore "gencos" against a decision by the regulator to reform the vesting contract regime.
- For a large European utility, market analysis and price forecasting in the Polish electricity market, including the assessment of coal-fired generation investments.
- For an investment bank, conducting due diligence on an Irish utility, including a review of the Single Electricity Market and the Irish and Northern Irish electricity retail markets.
- For a large European utility, market modelling work to support generation investment decision making in the UK market.
- For a consortium of investors, market due diligence, including detailed market modelling, for a proposed CCGT investment in the Balkans.

- For a private equity fund, preparing a report on the investment climate for renewable generation in the British market, including forecasting prices in the markets for power and renewables obligation certificates.

2009

- For London Underground Limited, providing ongoing support and advice in the course of the periodic review of the price clause in the PPP agreement with Tubelines Limited, focussing on the potential for future productivity growth and real input price inflation.
- For EDF Energy Networks, providing ongoing support, economic analysis and strategic advice in the course of the British electricity distribution price control review, with focus on benchmarking of costs, forecasting real input price inflation, and analysis of incentive mechanisms.
- For NIE PPB, support during the company's price control review focussing on modelling of working capital requirements.
- For the Department of Energy and Climate Change (DECC), analysing options for a regulatory framework for CO2 transportation infrastructure to enable the deployment of Carbon Capture and Storage technologies in the UK, including analysis of investment incentives under uncertainty about future demand for network infrastructure.
- For confidential investors, conducting market due diligence on UK, Irish and Italian generation assets.
- For BBL Company, advising on proposals for introducing an interruptible reverse flow service on the gas interconnector between the Netherlands and Great Britain.
- For the Lithuanian nuclear development company, market analysis and price forecasting for the Baltic markets and neighbouring European markets (Poland, Nord Pool, etc.), as an input to decision-making on a new nuclear plant in Lithuania.
- For a confidential client, support in preparation for a potential arbitration over the price clause in a gas supply agreement, reviewing the operation of gas markets in Britain and Belgium, and conducting econometric analysis of gas price series.
- For the International Finance Corporation, preparing a market report on the West African Power Pool (Ghana, Côte d'Ivoire, Benin and Togo), including wholesale electricity market modelling to establish optimal generation investment strategies.
- For a Turkish investor, modelling the evolution of the Turkish power market under a range of scenarios.

2008

- For EDF Energy Networks, forecasting future real input price inflation for the network business to support a submission to the industry regulator during distribution price control review.
- For Wales and West Utilities, helping to design an auction for "interruption rights" on their network, to ensure that the auction meets regulatory planning requirements, and advising on the design of a bid selection algorithm.

- For a grouping of Singaporean generators, reviewing the energy regulator's proposals on vesting contracts, including a review of the regulators' estimate of the long-run marginal cost of electricity generation and the level of vesting contract coverage required to mitigate market power.
- For PowerGas (Singapore), support in designing a regulatory framework for a proposed LNG terminal, including financial modelling and drafting regulatory proposals to the industry regulator for the calculation of allowed costs and tariffs.
- For a utility investor, market due diligence and revenue forecasting in support of the client's bid to acquire one of the state-owned Singaporean gencos that were being sold in 2008.
- For an investment bank, preparing detailed electricity market reports on the Romanian, Bulgarian and Polish electricity markets, including wholesale power price forecasts and a comparison of renewables investment incentives across the markets.
- For DEPA (Public Gas Corporation of Greece), reviewing the draft gas transmission network code for the Greek gas transmission system, with a focus on gas balancing, as well as transmission and LNG terminal access arrangements.
- For the Australian Energy Market Commission, writing a factual report, reviewing the arrangements that have been adopted in relation to Advanced Metering Infrastructure (AMI) in Great Britain.
- For ENBW, reviewing and appraising a regulatory benchmarking study of international electricity transmission system operators.
- For a confidential client, forecasting power prices for the Polish electricity market.
- For EOS, undertaking market due diligence and revenue forecasting for the generation capacity owned by EOS and Atel in Europe (including storage hydro, pumped storage, run-of-river, nuclear, and fossil-fuel plants in Switzerland, France, Germany, Italy, Hungary and Czech Republic).
- For a confidential asset management firm, preparing a review of the Russian electricity sector, focussing on the reform of the regulatory system for electricity distribution networks to introduce "RAB regulation".
- For confidential clients, advising on potential energy sector merger transactions.

2007

- For an investment bank, conducting due diligence on an Irish utility, including a review of the Single Electricity Market and the Irish and Northern Irish electricity retail markets.
- For E.ON UK Limited, providing support in its appeal to the UK Competition Commission against proposals to modify the gas uniform network code approved by the Gas and Electricity Markets Authority.
- For an independent power producer in the UK, preparing a report on the investment climate for renewable generation in the British market.

- For a UK electricity market investor, advising regarding investment strategies in the British electricity industry, including a description of the nature of electricity retail market competition.
- For Rede Electrica Nacional (Portuguese transmission network operator), designing an alternative regulatory system, containing incentives for cost minimisation, including financial modelling of the effects from the proposed system.
- For Fluxys, reviewing a benchmarking study undertaken at the request of the industry regulator to inform its “x-factor” decision.
- For National Grid Company, supporting an application to the EC for exemption from the Utilities Contracts Regulations, involving extensive research on European gas and electricity transmission and distribution networks.
- For the Regulation and Supervision Bureau, Abu Dhabi, modelling the electricity and water sectors to determine the least cost means of meeting electricity and water demand in Abu Dhabi over a 15-year horizon, using NERA’s EESyM model.
- For Wales and West Utilities, providing economic advice during the periodic price control review, with focus on the benchmarking of operational expenditure.
- For Gas Transport Services, a review of different cost accounting methodologies, including a review of regulatory practice in other European countries.
- For an investment bank, conducting due diligence on a British electricity distribution network, including a review of the regulatory risks that the company faces.
- For a large European utility, preparing training materials regarding the structure of the British gas and electricity markets (including retail market competition and a review of regulatory policy debates).
- For a confidential client, valuing of a portfolio of EU Emissions Trading Scheme CO2 allowances, for support in litigation.
- For the Office of Rail Regulation, modelling the impact of altering rail freight track access charges on the UK wholesale electricity market using NERA’s EESyM model.
- For Nuon and Essent, advising on a potential merger, in particular on consequences for the Dutch electricity market, involving modelling of Supply Function Equilibria.

2006

- For EDF Energy Networks, advising on the scope for distributed generation in the London electricity market.
- For The Gas Forum, advising on proposed reforms of the charging structure for gas transmission exit capacity in the UK, involving a cost benefit analysis of the proposed reforms and an analysis of the economics of gas pipeline capacity.
- For a grouping of Singaporean generators, reviewing the energy regulator’s proposals on vesting contracts to control market power.
- For a confidential client, advising on the competition effects of mergers on British energy markets.

- For a large European utility, conducting market due diligence and revenue forecasting for a gas storage asset in the Netherlands.

Report qualifications/assumptions and limiting conditions

NERA shall not have any liability to any third party in respect of this report or any actions taken or decisions made as a consequence of the results, advice or recommendations set forth herein.

This report does not represent investment advice or provide an opinion regarding the fairness of any transaction to any and all parties. This report does not represent legal advice, which can only be provided by legal counsel and for which you should seek advice of counsel.

The opinions expressed herein are valid only for the purpose stated herein and as of the date hereof. Information furnished by others, upon which all or portions of this report are based, is believed to be reliable but has not been verified. No warranty is given as to the accuracy of such information. Public information and industry and statistical data are from sources NERA deems to be reliable; however, NERA makes no representation as to the accuracy or completeness of such information and has accepted the information without further verification. No responsibility is taken for changes in market conditions or laws or regulations and no obligation is assumed to revise this report to reflect changes, events or conditions, which occur subsequent to the date hereof.

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