13 DECEMBER 2018

TRANSMISSION NETWORK PLANNING IN THE NEM

A REPORT FOR THE AUSTRALIAN ENERGY MARKET OPERATOR

FINAL REPORT

Table of contents

Key findings on a page

1 Approach to transmission planning

As with most electricity markets across the globe, the National Electricity Market is facing new challenges in managing the changes arising from the decarbonisation and decentralisation of the electricity system. In response to this, there is increasing recognition of the **potential benefits of a more systematic and coordinated approach to transmission network planning across wider geographic areas**.

The general consensus amongst policy makers and academics is that **market-based solutions** for delivering transmission investment (known as merchant investment) **may be effective in some cases, but, overall, is likely to result in 'too little' transmission capacity** relative to a socially optimal amount**.** Hence, regulatory interventions are required to ensure sufficient transmission capacity is delivered. These interventions need to be underpinned by a **transmission plan** to identify the 'right' amount of transmission capacity.

A general trend that has been observed across Europe and the US is a move towards planning transmission across wider geographic areas, driven, in part, by recognition of the benefits in managing an increased volume of intermittent renewables generation across wider areas. However, the differences in the implementation of this in Europe and the US provide, in our view, useful lessons for the NEM.

2 International experience: EU and US

Compared to the "European" model, we found that the "US ISO" model (loosely modelled on the PJM) has a number of advantages:

- A significant limitation of the European model is that planning at a European level (by an institution known as ENTSO-E) is purely advisory – decision making resides at the country level with host TSOs and regulators. This potentially inhibits cross-border transmission investments;
- By contrast there appear to be benefits of **consolidated decision-making** at the US ISO level;
- The US ISO model seems better than the European model in **coordinating and delivering transmission investments across multiple TO footprints** (within a single ISO jurisdiction);
- It integrates different asset needs (e.g. reliability and economic needs) into a **"seamless" transmission plan** that enables the different needs to be assessed in a holistic manner;
- It operates under a high level of **transparency** and SO **independence** and therefore appears not to have concerns about legitimacy of role; and
- In the US ISO model, **all transmission planning,** including local assets developed by TOs, is **integrated into a single PJM-wide plan.**

3 Opportunity for the NEM

As a single nation with much of the electricity market infrastructure (such as the wholesale market) already undertaken at a national (NEM-wide) level, **Australia seems to have greater opportunity to create a NEM-wide model of national transmission planning,** along the lines of those that operate as a US ISO.

This would enable the NEM-wide transmission planning model to **determine the investment requirements and enforce the delivery of these investments** more easily – rather than being advisory as is currently the case.

This main body of this report outlines specific recommendations in terms of changes to the NEM transmission planning that could help create a NEM-wide model of transmission planning.

Executive summary

1. In common with many other parts of the world, Australia's National Electricity Market (the "NEM")[1] – which is the electricity wholesale market for the eastern and southern states of Australia – is undergoing unprecedented change in the transition to a low carbon system. Technical, environmental, political and economic factors are driving changes in the way electricity is produced – with a greater emphasis on renewables production such as solar photovoltaic ("solar PV") and wind generation, and the progressive retirement of aging thermal generation, particularly coal-fired generation. Equally, customers' needs are also evolving with the roll out of smart meters, increasing digitisation, and the potential large-scale transition away from the internal combustion engine to electric vehicles. Furthermore, technological developments in batteries and other storage assets mean electricity may increasingly be stored in greater volumes (and more cheaply) than has historically been possible.

2. In light of these developments, it is unsurprising that the role of electricity transmission – the network of high voltage electricity cables that enables electricity to be conveyed from producers to consumers – will also need to evolve. Increasingly, transmission networks need to be developed in a way that enables electricity to be supplied reliably and cost-efficiently, given the challenges raised by greater intermittency and different technical characteristics of wind and solar generation (compared to thermal generation), the increasing penetration of distributed generation, and greater consumer engagement with the market (e.g. as enabled through smart metering and demand-side response).

3. In view of the rapid pace of change in the NEM, a panel led by Dr Alan Finkel was tasked to provide an independent review of the Australian electricity market and to advise on the blueprint for coordinated national reform (the "Finkel Review").[2] The Finkel Review subsequently identified that a more coordinated approach to planning the evolution of the transmission network is a crucial element to

[1] The NEM includes five price regions corresponding to five states: Queensland, South Australia, Tasmania, Victoria, and New South Wales (including the Australian Capital Territory).

[2] Commonwealth of Australia, Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, June 2017.

facilitate improvements in reliability and security in a cost-efficient way, in view of decarbonisation objectives.

4. The Finkel Review sets out three main recommendations for transmission planning. These recommendations are: [3]

- First, AEMO, supported by other stakeholders, to develop an integrated plan for the grid through a regional assessment to "*facilitate the efficient development and connection of renewable energy zones"* across the NEM;
- Second, AEMO, supported by other stakeholders, to develop a list of priority projects "*if the market is unavailable to deliver the investment required to enable the development of the renewable energy zones*"; and
- Third, to review how "*AEMO's role in national transmission planning can be enhanced*" to provide a system-wide view on transmission planning to "*ensure that investments are undertaken that meet the needs of the whole system"*.

5. In response to these recommendations, the Australian Energy Market Operator ("AEMO") has published an inaugural Integrated System Plan ("ISP") for the NEM, which is designed to provide an integrated view of transmission investment requirements in the NEM over the next twenty years.[4]

6. In this context, AEMO has commissioned the energy teams of FTI Consulting LLP ("FTI") and its subsidiary company Compass Lexecon (together "FTI-CL Energy") to prepare a report on current international transmission planning practices, and to identify lessons for AEMO and potential options for effective future model(s) of transmission planning for the NEM.

7. One of our key findings in this report is that a number of jurisdictions have been facing issues, similar to those identified in the NEM, arising from decarbonisation and decentralisation of the electricity system, and that there is **growing recognition of the potential need for a more systematic and coordinated approach to transmission network planning**, as well as a general trend towards consider wider transmission planning (or at least considerations of such planning). However, as yet, no jurisdiction has been able to resolve fully the issue of how best to plan a transmission network and integrate it with renewables investment, new technologies, and the rapid decentralisation of generation. Instead, all jurisdictions are facing three main issues to a lesser or greater extent. These are:

---

[3] Ibid, pp.124, pp. 127 and pp. 127 to 129.

[4] AEMO (July 2018) Integrated System Plan.

- First, the issue of **co-ordination** which exists in two dimensions. One dimension is the difficulty in coordinating "vertically" - between transmission investments and generation investments - given varying lead times and different commercial and regulatory drivers. Emerging technologies such as storage and demand-side response will complicate this vertical co-ordination problem further. The other dimension is the difficulty in coordinating "horizontally" - between transmission investments that connect or impact multiple networks - such as investments between neighbouring transmission systems or between higher voltage transmission networks and lower voltage distribution networks.
- Second, the issue of how to **assess** whether it is appropriate to undertake an investment. Transmission assets have long lead times, are relatively costly and might be operational for 40 years (or longer). Furthermore, the inherent network properties of transmission investments mean that benefits are typically dispersed unevenly across network users. Hence, the decision on whether to proceed with an investment now that might still be operating in the second half of the 21st century in an environment where technology, consumer preferences and government policies are evolving rapidly, and where benefits are unevenly dispersed is extremely difficult.
- Third, the challenge of **implementing** a transmission investment and charging system that is compatible with energy market operations and pricing. Some transmission investments are private goods, such as the minimal connection facilities for a new generator, and can be initiated, priced and charged accordingly. Other investments in the high voltage grid are needed to support reliability constraints with large externalities. These typically require coordinated planning and widespread sharing of costs. The articulation of the defining characteristics of transmission investments is, however, a challenge in all systems.

8. Our report examines the approaches adopted in other jurisdictions – mainly the US, GB, Germany and Europe – to these issues. Different jurisdictions take various approaches to this challenge and, to date, there appears to be no single 'best practice' in developing transmission networks. However, there are some lessons that can be learned and some elements of the transmission planning approaches in other jurisdictions could be considered for implementation in the NEM.
9. In this executive summary we set out an overview of our findings and, in turn:
   - explain why there is an enduring need for wider transmission planning;
   - set out some of the key findings from other jurisdictions' approaches to transmission planning; and

- draw out the main parallels between international and NEM approaches to transmission planning, and provide recommendations and suggestions for further analysis.

Why is there an enduring need for wider transmission planning?

10. The transmission investment of the past was driven mainly by the twin factors of security and affordability, but concerns over climate change have meant a third factor – that of sustainability – has now also become a critical factor in driving transmission investment in many countries. In particular, instead of being driven primarily to meet perpetually growing demand, transmission is now increasingly driven by the need to address the challenges posed by deployment of intermittent renewables, and by changing demand and supply fundamentals (notably slowing demand growth and the expected retirement of large thermal generators).

11. Meanwhile, the global trend in the 1980s and 1990s was that policy makers sought to increase the efficiency of the electricity sector by privatising generation companies and introducing competition into the generation sector with a view of improving the operational and investment efficiency. A similar approach was considered for investment in the transmission sector, with the underlying logic being that, investors might, in response to price signals, choose to invest in transmission assets that allowed them to capture the revenues from allowing low cost electricity to flow to meet demand served by higher cost electricity.

12. However, the so-called merchant transmission investment model has been identified by many commentators (notably academics such as Joskow and Tirole in 2005, for example)[5] to suffer from a number of 'market failures' which mean that the 'market' alone cannot be relied on to deliver the appropriate amount of transmission investment. Typically, developers of merchant interconnectors would only consider the costs of transmission investment against the benefits they can capture and retain (e.g. congestion rent), but would not consider the impacts on the wider electricity system (e.g. the benefits to consumers of lower electricity prices). The general consensus amongst policy makers and academics is that merchant-only investment could result in a socially sub-optimal volume of investment (in practice, this is likely to be 'too little' transmission capacity rather than 'too much'). As a result, there has been an ongoing need to regulate some transmission investment and recover the costs of the network through mandatory charges on network users. This need to regulate has also meant that there has been an ongoing need for a transmission planning function to ensure the transmission requirements of consumers are met appropriately.

13. Importantly, there are costs associated with not taking appropriate action in delivering transmission network investments (whether they are merchant or regulated). These costs can manifest themselves for example in higher electricity prices (as less efficient dispatch is used to resolve congestion issues) or through security of supply issues. To the extent that regulated investments typically need to be justified to the regulator it seems that there is an inherent bias towards less (rather than more) transmission investment.

14. In terms of how such transmission planning is undertaken, there is an inevitable tension between local planning and national planning. A more local transmission planner (for example a regional TO) has the advantage of having a more in-depth understanding of the network within its jurisdiction and is likely to be better at stakeholder management.

5 Joskow and Tirole (2005), Merchant Transmission Investment.

15. However, such a local planner will, by design, concentrate on planning the network within its geographic scope and is less likely to divert its scarce resources to planning how the network might interact with neighbouring networks. Often commercial and political pressures encourage this behaviour – if it is seen as responsible for “keeping the lights on” in its geographic footprint, then it will invest accordingly in its area. Equally, many regulatory regimes have tended to reward a greater roll out of assets – this potentially increases a transmission planner’s tendency to build more within its ‘patch’ with less consideration of a system-wide view. **By contrast, a national planner with a wider geographic scope will be able to take a more holistic view of the overall need for transmission investment.**

16. As technology and customers’ needs are evolving faster than ever before, this is changing the balance of costs and benefits of local versus wider transmission planning:

    - Prior to the rise of renewables, the benefits of more localised planning might have outweighed those of a wider geographic scope. At that time, the prevalent generation technology was thermal generation with broadly similar marginal costs of production. Hence, the gains from trading electricity between regions were likely to be relatively low and, moreover, as generation was despatchable, each planner could concentrate solely on its own geographical area by investing in accordance with local requirements.
    - However, the rise of large volumes of intermittent generation is likely to change this balance. Proliferation of intermittent generation means that significant gains from trade across greater distances (from areas of high production to high demand) are now more likely. In addition, sharing reserves of despatchable generation across wider regions is now more likely to be a more cost effective way of maintaining security of supply compared to each local planner focusing on maintaining reserves at its local level (as the latter will result in a larger volume of relatively under-utilised generation).

17. While the benefits of localised planning used to be, prior to the rapid increase in intermittent renewables generation, more likely to outweigh those of a wider geographic scope, this balance may now be shifting. **As a result, the gains from transporting electricity around NEM are likely to have increased relative to the historical levels and have therefore made more coordinated system planning more attractive.**

18. Furthermore, as the energy system becomes more complex, the future becomes increasingly uncertain as well – this means that the way potential investments are assessed and how the benefits are calculated are also becoming more complex.

How do other countries approach the transmission planning challenge?

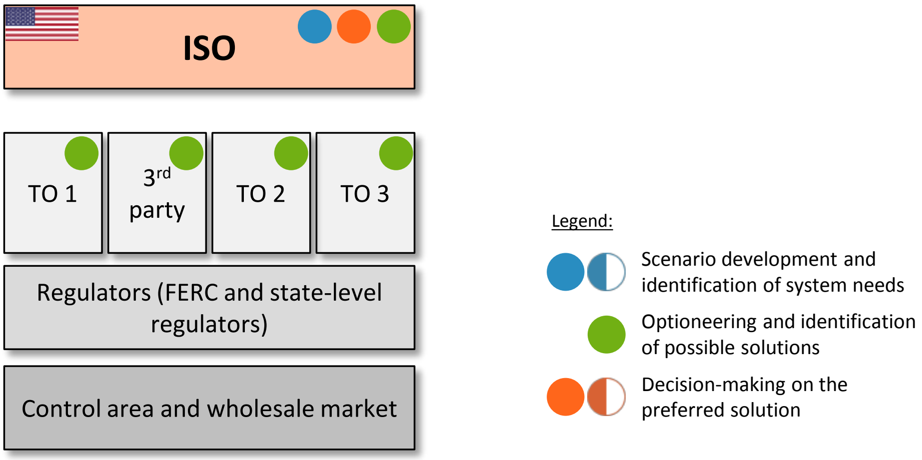
19. To understand how these issues might be addressed, our report examined the approach to transmission planning mainly in four jurisdictions. These were:

- **United States** (NYISO and PJM in particular): where transmission planning is led by an independent system operator ("ISO"), sometimes over multiple states;
- **Great Britain**: where transmission planning is led by the SO and approved by the regulator (Ofgem) depending on the asset type, and where the SO is fully independent from the TO in some areas (Scotland) but not in others (England and Wales);
- **Germany**: where there are four transmission system operators (with transmission operation and system operation as a single entity in each of the four regions), each contributing to the national transmission plan based on assessments in their respective regions; and
- **Europe**: as a 'supra-national' planner intended to coordinate cross-border transmission investments.

20. From the outset, based on the detailed analysis of the four jurisdictions above, we identified two overarching types or 'models' of transmission planning.

21. First, we identified the "**US ISO model"** where a single ISO covers (in geographic terms) multiple TOs, and may in some cases span several States. The key roles of the SO, TOs and regulators in relation to other market participants are illustrated in Figure 1 below. This particular stylised version of the US ISO model has been developed in line with the PJM case study (rather than other US-based ISOs).

Figure 1: US ISO model: summary of key roles

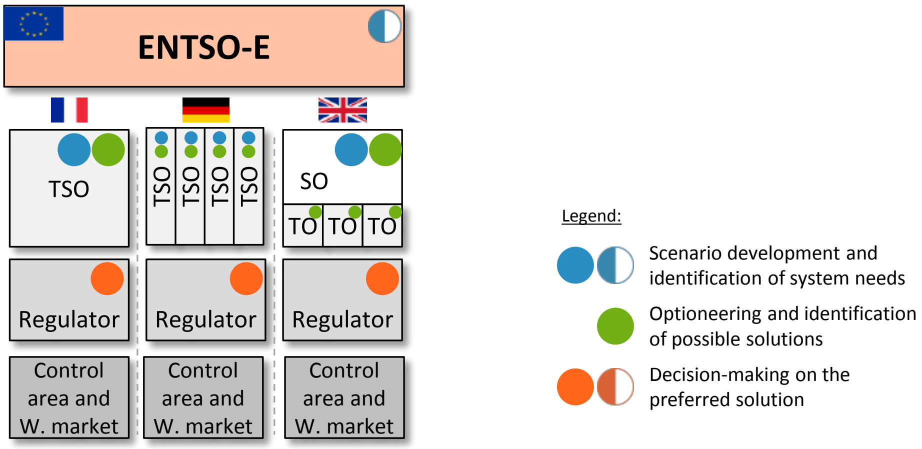


Source: FTI-CL Energy analysis.

22. Second, we identified the "**European model**", where multiple SOs and TOs interact within a Europe-wide framework. In this model, we consider that the transmission planning approaches used in Germany and GB are the constituent parts of the overall European model. In the European model, ENTSO-E as the pan-European entity representing national SOs covers (in geographic terms) multiple TSOs, SOs and TOs[6] across different countries. The key roles of the SO, TOs, regulators and other market participants are illustrated in Figure 2 below.

6 Some European countries have a single TSO such as France; while others have multiple TSOs (e.g. Germany), and in other countries there is a separation between SO and TO functions (e.g. Great Britain).

Figure 2: European model: summary of key roles



Source: FTI-CL Energy analysis.
Note: "W.market" stands for "wholesale market".

23. We compared the two overarching models (the US ISO model and the European model) in terms of the roles played by different parties in transmission planning, and set out their key advantages and disadvantages below.

24. One of the key benefits of the US ISO model is that the decision-making regarding transmission solutions is consolidated at ISO level, and this is done with a high level of transparency and independence of the SO. In addition, ISOs such as PJM appear to be effective at delivering transmission investments that link multiple TO footprints (this is not necessarily the case in the European model). Finally, the US ISO model uses an approach whereby different asset needs (notably reliability and economic needs) are integrated into a "seamless" transmission plan that enables the different needs to be assessed in a holistic manner.

25. However, the US ISO model faces its own challenges. In particular, while FERC has significant legislative powers, transmission planning is often left to the individual ISOs whose mandate is to plan for their own respective jurisdictions. ISOs plan to meet their own reliability requirement in their respective jurisdictions and are unable to rely on the availability of resources outside its geographical footprint. Hence, the development of interregional assets (i.e. between different ISO footprints) is relatively complex, and relatively uncommon, unless there is a strong economic case to be made. One of the aims of FERC Order 1000 (issued in July 2011)[7] has been to provide supporting rules, but these are yet to drive significant volumes of new interregional investments.

26. In the European model, ENTSO-E plays an advisory role, eliciting information from national TSOs, and aims to coordinate cross-border investments between independent jurisdictions (which are, in this model, sovereign states). Similarly to the US model, there are country-level regulators (corresponding to the state-level regulators in the US), but there is no FERC equivalent in Europe.

27. A key feature of the European model is that each country functions as an individual control area (in terms of the SO balancing, albeit with some coordination between TSOs at the day-ahead stage) and a wholesale market. National authorities (often TSOs and/or regulators) retain the ultimate responsibilities for investment approvals, which complicates, and, in turn, probably deters, investment in cross-country interconnections.

28. While ENTSO-E is relatively active, the key challenge is that it inevitably lacks the political power to enforce a transmission plan – its plans are merely advisory. Furthermore, we see little evidence that EU Member States have been willing to cede too much control to a pan-national planning organisation (as observed, for example, in the development of individual capacity mechanisms by each EU Member State).

29. In addition, ENTSO-E, in its advisory role for cross-Europe coordination, does not currently have any system operation role(s). This is different from the US ISO model, where a single ISO covers an area that corresponds to a single control area and wholesale market. In other words, the European model represents a fragmented market, where the function of the system operator (and wholesale market operator) is disjointed from the transmission planning role.

---

7 United States of America Federal Energy Regulatory Commission 18 CFR Part 35, Docket No. RM10-23-000; Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities (Issued July 21, 2011).

30. Similarly to the US ISO model, the regulatory treatment (i.e. investment cost recovery) in the European model varies by country and there is no single 'best' approach applied by different European countries.

31. Overall, we find that the US ISO model (loosely modelled on the PJM model) is better than the European model in coordinating and delivering transmission investments across multiple TO footprints (within a single ISO jurisdiction).

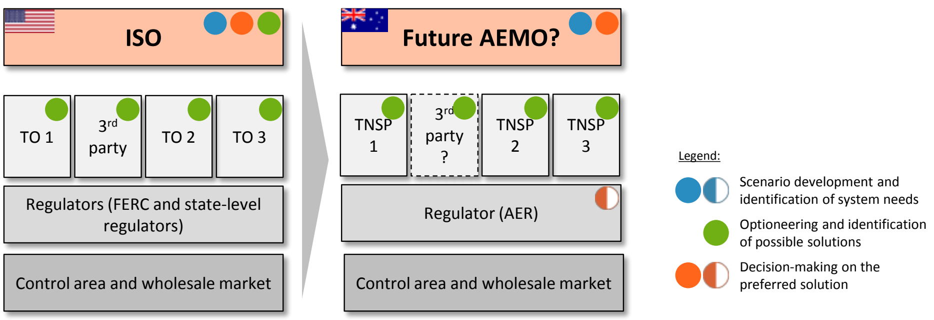
Parallels between international and NEM transmission planning approaches

32. In this report, we set out the current framework adopted in the NEM for transmission planning. We found that there are some similarities between the NEM and the European model, but overall the parallels between the NEM model and the ISO model are stronger:

- Both models feature an independent system operator (ISO / AEMO).
- Both models serve to operate within a single country (but multiple states) and in both cases a single system operator oversees multiple transmission operators (TOs/TNPSs); and
- Both models feature a single wholesale market covered by the ISO/AEMO jurisdictions. This means that in the NEM case, the legal "infrastructure" for a cross-state entity already exists and, in principle, could be extended to include a NEM-wide transmission planning role.

33. Moreover, we find that the US ISO model 'blueprint' appears to be the closest framework that the NEM could draw relevant lessons from. In Figure 3 below, we compare the US ISO model to a theoretical "future AEMO" model, where AEMO takes on a more system-wide transmission planning role. In this "future AEMO" model, the functions of the SO, TOs/TNSPs and the regulator are aligned more closely to the US ISO model.

Figure 3: Future AEMO model: summary of key roles



Source: FTI-CL Energy analysis.

34. We find that the theoretical “future AEMO” model seeks to benefit from several attractive features of the US ISO model (and in particular from the characteristics of PJM specifically). These attractive features include the following:

- Independence and transparency of the PJM ISO helps ensure that the transmission solutions are objective, credible and in the consumer interest;
- There is a balance between local planning[8] and PJM-wide planning for networks where the benefits are more widely distributed, but all transmission planning, including local assets, is integrated into a single PJM-wide plan;
- The role of a regional transmission planner is combined with the responsibility for balancing over the same footprint – potentially enabling better assessment of trade-offs between different solutions;
- The model supports effective delivery of transmission investments that connect multiple TO footprints (i.e. in terms of investment across TO boundaries);
- Scenarios are developed in a consistent and transparent manner which helps align the market participants’ expectations;
- Multiple asset needs (notably the linkages between reliability and economic needs) are rolled into a single integrated plan;
- Appropriate checks and balances are in place (through various committee roles) to validate the overall transmission plan; and
- Possible solutions from third party developers are considered by the transmission planner (FERC Order 1000 prevents ISOs from intentionally excluding third parties from the transmission planning process).

35. Despite these attractive features, the US ISO model cannot be directly transposed to the NEM context. Rather, it is important that the NEM-specific features are appropriately reflected in the design of the “future AEMO” model.

[8] Local planning is led by TOs, e.g. for assets below 100kV where benefits accrue to physically proximate customers, but must be introduced to the PJM regional planning process

- Giving AEMO a stronger role in identification of system needs and making ultimate decisions about prospective investments seems likely to enable better coordination of investments among TNSPs. Our analysis of the US ISO model indicates that consolidated decision-making and planning based on a consistent set of assumptions across ISO footprint level is an attractive feature, as long as it is supported by well-developed processes to ensure stakeholder buy-in. This could be a helpful precedent to consider in the "future AEMO" model.
- Linkages between AEMO and the insight from individual TNSPs would need to be strengthened (and possibly mandated/incentivised) to ensure that the local knowledge of the networks is appropriately leveraged at NEM level. In other words, TNSPs would need to retain a critical role in identifying options for transmission network solutions based on their local knowledge.
- In addition, to ensure AEMO can deliver on a single national plan, AEMO would need to be independent and transparent (and also to be seen as such).
- AEMC would retain a critical role of designing the rules for AEMO and other market participants to follow in delivering their new roles and responsibilities.
- AER would also need to retain a strong role in determining the regulatory treatment of the cost recovery process (including, for example, assessing the reasonableness of costs and how cost overruns are handled).

36. **On balance, it seems to us that Australia has a greater opportunity for national transmission planning in contrast to the EU and the US.** Although Australia's energy markets still have much emphasis at the state level, **the fact it is a single nation with much of the electricity market infrastructure (such as the wholesale market) already undertaken at a national level means that there is a greater opportunity to create a model of national planning.** This would enable the transmission planning model to determine the investment requirements and enforce the delivery of these investments more easily – rather than being advisory as is currently the case.

37. We have also considered whether any of the international precedents could serve as a 'blueprint' for the NEM to follow. Based on the analysis of various the jurisdictions in Section 4, and the NEM framework set out in Section 5, it seems that the European model may not be appropriate for the NEM. By contrast, given the parallels between NEM and PJM, it seems reasonable to explore further how some of the attractive features of the PJM ISO transmission planning model could be applied in the NEM, while ensuring that the key features of the NEM are

retained. By considering the potential lessons from the US ISO model, the NEM appears to have a good opportunity to move towards a more coordinated transmission planning approach, particularly between TO footprints.

38. Therefore, based on our evaluation of international experience, we have suggested several areas for further analysis[9] in the NEM context.

39. First, in relation to the role of the transmission planner:

- **#1: Consider the potential for a system-wide transmission planning function with a mandatory rather than advisory role.**

40. Second, in relation to the roles played by other parties:

- **#2: Consider how transmission planning is linked to the actual delivery of the asset;**
- **#3: Ensure non-network solutions are considered, particularly when evaluating options for meeting an identified need; and**
- **#4: Consider how third-party developers should be included in transmission planning to encourage lower cost solutions.**

41. Third, in relation to cost allocation:

- **#5: Explore how the beneficiary-pays principle should be reflected in the cost allocation arrangements, so the costs and benefits of transmission investment are allocated fairly.**

[9] In a separate FTI-CL Energy report (see FN16), we also suggest additional areas of analysis related to (1) the pros and cons of restricting the evaluation criteria to consumer surplus, and potentially congestion rents, rather than a pure social welfare; (2) the use of a social discount rate in investment tests; and (3) whether investment tests for transmission networks in the NEM should distinguish between asset needs and/or asset types. These suggestions are not repeated in this report.

1. Introduction

1.1 The National Electricity Market ("NEM") is the electricity wholesale market for the eastern and southern states of Australia.

1.2 In common with many other parts of the world, the NEM is undergoing unprecedented change in the transition to a low carbon system. Technical, environmental, political and economic factors are driving changes in the way electricity is produced – with a greater emphasis on renewables production such as solar photovoltaic ("solar PV") and wind generation, and the progressive retirement of aging thermal generation. Equally, customers' needs are also evolving with the roll out of smart meters, increasing digitisation and the potential large-scale transition away from the internal combustion engine to electric vehicles. Furthermore, technological developments in batteries and other storage assets mean electricity may increasingly be stored in greater volumes (and more cheaply) than has historically been possible.

1.3 In light of these changes, it is unsurprising that the role of electricity transmission – the network of high voltage electricity cables that enables electricity to be conveyed from producers to consumers – will also need to evolve. In today's world the transmission networks (and non-network solutions, where appropriate) need to be developed in a way that enables electricity to be supplied reliably and cost-efficiently despite the complex challenges raised by greater intermittency and different technical characteristics of wind and solar generation (compared to thermal generation), increasing penetration of distributed generation, and greater consumer engagement with the market (e.g. as enabled through smart metering and demand-side response).

1.4 In view of these changes and the challenges presented to the NEM, a panel led by Dr Alan Finkel was tasked to provide an independent review of the Australian electricity market and to advise on the blueprint for coordinated national reform (the "Finkel Review").[10] The Finkel Review subsequently identified that a more coordinated approach to planning the evolution of the transmission network is a crucial element to facilitate improvements in reliability and security in a cost-efficient way, in view of decarbonisation objectives.

1.5 The Finkel Review sets out three main recommendations for transmission planning. These recommendations are:

- First, AEMO, supported by other stakeholders, to develop an integrated plan for the grid through a regional assessment to "*facilitate the efficient development and connection of renewable energy zones"* across the NEM;[11]
- Second, AEMO, supported by other stakeholders, to develop a list of priority projects "*if the market is unavailable to deliver the investment required to enable the development of the renewable energy zones*";[12] and
- Third, to review how "*AEMO's role in national transmission planning can be enhanced*" to provide a system-wide view on transmission planning to "*ensure that investments are undertaken that meet the needs of the whole system"*.[13]

1.6 In response to these recommendations, the Australian Energy Market Operator ("AEMO") has published an inaugural Integrated System Plan ("ISP") for the NEM, which is designed to provide an integrated view of transmission investment requirements in the NEM over the next twenty years.[14]

---

10 Commonwealth of Australia, Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, June 2017.

11 Ibid, p.124.

12 Ibid, p.127.

13 Ibid, pp.127 to 129.

14 AEMO (July 2018) Integrated System Plan.

1.7 In this context, AEMO has commissioned the energy teams of FTI Consulting LLP ("FTI") and its subsidiary company Compass Lexecon (together "FTI-CL Energy") to prepare a report on current international transmission planning practice, and to identify lessons for AEMO and potential options for effective future model(s) of transmission planning for the NEM.[15]

1.8 This report follows on a previous publication by FTI-CL Energy (September 2018) that focused specifically on the investment tests used for transmission planning.[16]

1.9 In this introductory section, we therefore describe the purpose and objectives of this report, explain the limitations of the scope of work undertaken and set out the structure of the remainder of this report.

A. Purpose and objectives of this report

1.10 The purpose of this report is to identify and articulate key lessons from experiences in other jurisdictions that could be used to inform potential changes to transmission planning in the NEM. This is intended to support the system's objectives of increasing reliability and security of the energy system cost-effectively while promoting decarbonisation objectives.

1.11 Transmission planning refers to the entire process of developing a transmission plan to inform the delivery and operation of transmission investments. Each transmission plan consists of many 'key design parameters' or 'key levers' (that make up the governance arrangements, rules and methodology) that must be considered.

1.12 In this report, we:

- identify the need for transmission investment and consider the different 'design parameters' in transmission planning;
- examine and compare transmission planning in selected international jurisdictions; and

---

15 This report discusses transmission investment for the electricity sector unless stated otherwise. We consider the importance of co-optimising electricity and gas transmission investment in FN48.

16 FTI-CL Energy (2018) Investment tests for transmission networks, dated 6 September 2018, accessible at the AER website: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-the-application-guidelines-for-the-regulatory-investment-tests-for-transmission-and-distribution/draft-decision.

- evaluate the current transmission planning arrangements in the NEM and identify areas in the framework where the NEM approach diverges from other international precedents.

1.13 Based on this analysis we articulate the key lessons on transmission planning that can be learnt from other jurisdictions and areas that could be explored further in the NEM to benefit consumers.

B. Restrictions

1.14 This report has been prepared solely for the benefit of AEMO for use for the purpose described in this introduction.

1.15 FTI accepts no liability or duty of care to any person other than AEMO for the content of the report and disclaims all responsibility for the consequences of any person other than AEMO acting or refraining to act in reliance on the report or for any decisions made or not made which are based upon the report.

C. Limitations to the scope of our work

1.16 This report contains information obtained or derived from a variety of sources. FTI has not sought to establish the reliability of those sources or verified the information provided.

1.17 No representation or warranty of any kind (whether express or implied) is given by FTI to any person (except to AEMO under the relevant terms of our engagement) as to the accuracy or completeness of this report.

1.18 This report is based on information available to FTI at the time of writing of the report and does not take into account any new information which becomes known to us after the date of the report. We accept no responsibility for updating the report or informing any recipient of the report of any such new information.

D. Structure of this report

1.19 This report has the following sections:

- **Section 2** describes the evolving need for transmission investments, the wide range of benefits, why there may now be a case for more coordinated system-wide planning;
- **Section 3** summarises the transmission planning lifecycle and the main design parameters of a transmission planning framework;

- **Section 4** provides an overview of international transmission planning practice, drawing on multiple jurisdictions from the US and Europe;
- **Section 5** summarises the main features of the transmission planning framework in the NEM and highlights areas where the NEM differs from the international practice; and
- **Section 6** sets out the key lessons that could be considered in the NEM, based on the assessments in the previous sections.

1.20 In addition, **Appendix 1** sets out the international case studies on transmission planning in further detail. **Glossary** of key terms used in this report is attached at the end of this report.

2. The need for wider transmission planning

2.1 A transmission network enables the transportation of electricity from an entry point where it is generated (or injected from another network), to an offtake point where it is consumed (or distributed onto another network). Transmission networks have played (and continue to play) a critical role in ensuring both the reliability of a system's electricity supply, by ensuring electricity can be transported to where it is required at all times and the overall affordability to society, by enabling the delivery of electricity from lower cost sources of production to the centres of load.

2.2 While the transmission investment of the past was driven mainly by the twin factors of security and affordability, concerns over climate change have meant a third factor – that of sustainability – has now also become a critical factor in driving transmission investment in many countries. In particular, instead of being driven primarily to meet perpetually growing demand, transmission is now increasingly driven by the need to address the challenges posed by deployment of intermittent renewables and by changing demand and supply fundamentals (notably slowing demand growth and the expected retirement of large thermal generators).

2.3 In this section we set out, in turn, why the market cannot be relied upon to deliver a socially optimal amount of investment (Section A), why there is an enduring need for transmission investment planning (Section B) and how the appropriate balance between local and wider transmission planning has evolved (Section C).

A. Ensuring the appropriate level of transmission investments

2.4 Transmission assets can provide a wide range of benefits to various stakeholders and their impacts depend on the details of the design of the electricity market. In an electricity market transmission assets can be built within a single price zone or between multiple zones with price differentials.

2.5 Within a given price zone, the socio-economic benefits typically include the *reduction in congestion costs*[17] (although congestion is treated differently in different jurisdictions which may impact the welfare distribution).

2.6 Between price zones, i.e. when there are price differentials between either end of a given transmission asset, the benefits include a change in consumer surplus, producer surplus and congestion rents between the connecting zones. These assets are often referred to as 'interconnectors'.[18,19]

2.7 As an illustration of the different approaches, Figure 2-1 shows the economic value produced by an interconnector that connects across two regions with separate price zones. This figure shows the stylised demand and supply curves of electricity in both the exporting and importing regions over the long-run. This means that the long-run curve implicitly includes any additional dynamics that might occur in response to the change in prices. For example, changes in prices may cause generators to enter or exit, which in turn will negate some of the price impact of an interconnector transmission investment. Additionally, any 'lumpiness', i.e. large coal plants being decommissioned, or large transmission investments being built would be taken into account in the long-run curves.

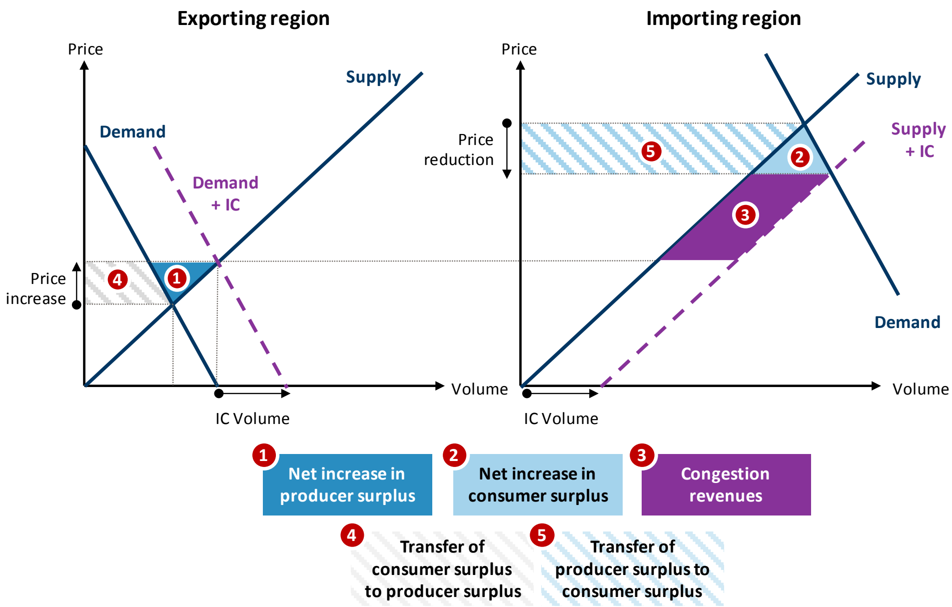
---

[17] In the US, these are measured as the change in the cost of the unit commitment and dispatch.

[18] This definition may vary in different jurisdictions. For example, in US energy markets with nodal pricing, all transmission assets can be referred to as interconnectors given that there are price differentials between nodes.

[19] More detailed analysis of this topic can be found in previous FTI-CL Energy work on 'Investment tests for transmission networks', dated 6 September 2018, accessible at the AER website: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-the-application-guidelines-for-the-regulatory-investment-tests-for-transmission-and-distribution/draft-decision.

Figure 2-1: Cost benefit analysis of an interconnector



Source: FTI-CL Energy analysis.

2.8 As shown in Figure 2-1 above, the construction of an interconnector has an impact on the producers in the exporting region (through higher prices) and consumers in the importing region (through lower prices). In addition, congestion rent can be captured by the owner of the interconnector.[20]

- Congestion rent (or congestion revenues) is the difference between the prices at which electricity is exported from one point and the prices at which electricity is imported at another point, multiplied by the volume of electricity flow.
- Consumer surplus is the difference between the total value consumers would be willing to pay and the quantum actually paid for electricity (primarily driven by the shape of the demand curve and the electricity prices).

20 The new interconnector may also lead to an additional price convergence between the two regions, which would in turn reduce the congestion revenues that any pre-existing interconnectors across the two same zones would earn. Similarly, the wholesale price changes in the connecting regions may lead to second-order impacts on interconnectors linking to only one of the two connecting regions. Both of these effects are known as a "cannibalisation effect", which be taken into account as an additional welfare factor.

- Producer surplus is the difference between the revenue producers actually receive less the cost of production of electricity (driven by the shape of the supply curve and the electricity prices).

2.9 A key question when evaluating the benefits of a transmission asset is which beneficiary should be considered when evaluating an investment. A pure 'economic efficiency' approach would consider the areas 1+2+3 only, i.e. accounting for the net economic welfare impact and ignoring any distributional impacts.[21]

2.10 In principle, the market can deliver some transmission investments on its own (i.e. without a planner being involved) through merchant investments.[22] This is the case particularly for investments that are separate from the incumbent network (between two price zones) and hence receive congestion rent.[23]

2.11 As shown in Figure 2-1, transmission investments are considered to be efficient from a socio-economic perspective and should be delivered if the benefits (Areas 1+2+3) exceed the cost.

21 Alternative approaches are possible and have been used elsewhere. For example, a consumer-driven approach might consider only the consumer surplus (and a portion of congestion revenues) i.e. areas 2 + 5 + part of area 3. This is the approach relied on by Ofgem when assessing the benefits of a new interconnector under the Cap and Floor regime. However, this approach is only practicable for a jurisdiction that focuses solely on the welfare of its own consumers – i.e. where the two jurisdictions are two different countries. This is not the case for the NEM.

22 A large volume of academic research has been dedicated to the consideration of whether merchant transmission investments can deliver a socially optimum volume of transmission. Theoretical models show that under a set of relatively strict conditions all investments that are profitable for the investor in new transmission capacity are efficient (e.g. Joskow and Tirole (2005), pp 241). However, research has also shown that these conditions are not always met in practice, and that in many cases there tends to be an under-investment in merchant interconnector compared to the social optimum. More recent research therefore found that "efficient investment may need regulatory mandates and a regulatory cost allocation" (Hogan (January 2018) A Primer on Transmission Benefits and Cost Allocation).

23 As these investments are more easily separable, these investments can be developed by third parties such as generators or independent transmission developers/investors.

2.12 However, not all efficient investments (from the societal perspective) are necessarily profitable for the owner of the transmission capacity. This could be the case where the congestion revenues are not sufficient or not capturable, due to lack of property rights, by the owners, or because the value of the congestion rent (i.e. Benefit 3) – which is the only element that can be easily recovered by a merchant developer – is lower than the investment cost.

2.13 If this is the case, or if any of the assumptions underpinning the finding (see FN22) above fail, then merchant-only investment could result in a socially sub-optimal volume of investment (in practice, this is likely to be 'too little' transmission capacity rather than 'too much').

2.14 Therefore in practice, on its own, merchant investment tends to be unable to provide an appropriate level of transmission investment to deliver security of supply, cost minimisation and decarbonisation outcomes.

2.15 As it is now generally agreed that merchant investors cannot be relied upon to deliver the optimal transmission investment, transmission investment is typically delivered by regulated monopolies. The decision as to how much transmission investment by regulated monopolies is the 'right' amount (from a social or from a consumer perspective, depending on the statutory objectives in a given jurisdiction) needs to be decided by someone. The decision maker is typically not the regulated monopoly itself (as otherwise this would risk leading to too much investment). To reach this decision, and to manage the increasingly complex system and to coordinate multiple parties, policy-makers, regulators and governments have typically designed and relied on a transmission plan to inform industry on the required transmission solutions.

B. Transmission plan

2.16 The transmission plan is intended to inform the design, delivery and operation of a transmission solution while also considering these arrangements in advance of selecting the solution. We refer to the entire process of developing the transmission plan, including the governance arrangements, rules and methodology, as the **"transmission planning framework**".

2.17 The transmission planning framework might, initially at least, have represented an updating of (or an extension to) the planning framework that had existed within the vertically-integrated business – albeit to take account of the new number of players, their incentives and more diffuse information sources. Such a framework typically serves to determine the key roles and responsibilities of different parties, the economic or technical principles against which a proposed investment should be assessed[24] and the principles for deciding how costs and benefits might be allocated amongst various parties.

2.18 A transmission planning framework typically articulates:

- the roles and responsibilities of different parties including, in some cases, the role of a system-wide transmission network planner;
- the economic principles underpinning the investments undertaken in the energy system (such as cost-benefit analysis);
- how long-term forecasts of the underlying supply and demand for electricity (e.g. scenarios) should be articulated and used by different parties;
- the approach to the identification of the need,[25] and the delivery of the appropriate transmission solution to produce the greatest benefit;[26]
- how the solution should be assessed and under what conditions it can be deemed to be beneficial, at the time of the evaluation being performed, given a range of possible scenarios reflecting the expected future prevailing market conditions when the asset is completed;
- the wider coordination, transparency and information-sharing responsibilities, as well as focus on promoting competition and innovation; and

24 For example, in the NYISO, the system operator evaluates both the technical viability and the cost-efficiency of potential transmission investments.

25 Identification of the optimal transmission investment is not always straightforward. For example, in the NEM, intra-regional congestion is potentially masked by unusual bidding incentives for market participants, which may therefore prevent beneficial investments from being identified.

26 Some policy makers may choose to apply different criteria in lieu of the social welfare criterion, for example cost minimisation, or maximisation of consumer-only benefits. However, these approaches are less common.

- in some, but not all, the distributional principles for allocating costs and benefits (and by implication, risks) among parties.

2.19 As such, a transmission investment planning framework tends to be highly complex, as they need to reflect diverging interests of different parties, the specificities of individual jurisdictions and the evolving nature of the electricity market. As a result, although there are common themes in the approach to planning transmission, there is no 'one size fits all' approach to transmission investment planning framework and the preferred approach tends to differ across jurisdictions and over time. In particular, there is often a choice to be made between two key variants: local planning and national planning. This is explored in the following sub-section.

C. Balance between local and wider transmission planning

2.20 In network planning in general, there is an inevitable tension between more local planning and more national planning. A more local transmission planner (for example a regional TO) has the advantage of having a more in-depth understanding of the network within its jurisdiction and is likely to be better at stakeholder management.

2.21 However, such a local planner will, by design, concentrate on planning the network within its geographic scope and is less likely to divert its scarce resources to planning how the network might interact with neighbouring networks. Often commercial and political pressures encourage this behaviour – if it is seen as responsible for "keeping the lights on" in its geographic footprint, then it will invest accordingly in its area. Equally, many regulatory regimes have tended to reward a greater roll out of assets – this potentially increases a transmission planner's tendency to build more within its 'patch' with less consideration of a system-wide view. By contrast, a national planner with a wider geographic scope will be able to take a more holistic view of the overall need for transmission investment.

2.22 As technology and customers' needs are evolving faster than ever before, this is changing the balance of costs and benefits of local versus wider transmission planning:

- In the period prior to the rise of renewables the benefits of more localised planning might have outweighed those of a wider geographic scope. At that time, the prevalent generation technology was thermal generation with broadly similar marginal costs of production. Hence, the gains from trading electricity between regions were likely to be relatively low and, moreover, as generation was despatchable, each planner could concentrate solely on its own geographical area by investing in accordance with local requirements.
- However, the rise of large volumes of intermittent generation is likely to change this balance. Proliferation of intermittent generation means that significant gains from trade across greater distances (from areas of high production to high demand) are now more likely. In addition, sharing reserves of despatchable generation across wider regions is now more likely to be a more cost effective way of maintaining security of supply compared to each local planner focusing on maintaining reserves at its local level (as the latter will result in a larger volume of relatively under-utilised generation).

2.23 While the benefits of localised planning used to be, prior to the rapid increase in intermittent renewables generation, more likely to outweigh those of a wider geographic scope, this balance may now be shifting. As a result, the gains from transporting electricity around NEM are likely to have increased relative to the historical levels and therefore made more coordinated system-wide planning more attractive.

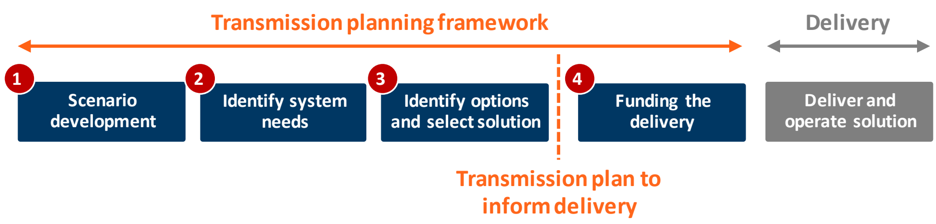
2.24 The choices that different jurisdictions make between local and wider planning are described in the case studies in Section 4.

3. Approach to transmission planning

3.1 A framework for planning investments in transmission networks potentially covers a wider range of activities: it enables the development of a robust and credible transmission plan to deliver the required investment to connect generation and demand. Also, the framework can consider an appropriate cost recovery mechanism and identify and address any distribution impacts of the investment itself. This section explores the key features of a transmission planning framework that enable policy makers and the market to develop and implement a transmission plan.

3.2 Investments in transmission assets are, to a lesser or greater extent, generic across all jurisdictions and tend to follow a similar lifecycle regardless of jurisdiction. This lifecycle is summarised in Figure 3-1 below.

Figure 3-1: Typical project lifecycle and key activities



Source: FTI-CL Energy analysis.

3.3 As illustrated above, the project lifecycle typically involves five distinct stages. Although in practice these stages will not be a straightforward linear process (with later stages influencing the earlier stages through a more sophisticated planning process) these are set out below sequentially, for ease of exposition:

- **Stage 1: Scenario development** that sets out a view (or views) on the expected evolution of the electricity market. This stage may be undertaken repeatedly, following an annual cycle to update the scenarios;
- **Stage 2: Identify need(s)** which identifies where (or when) transmission investment might be required to deliver specific outcomes;

- **Stage 3: Identify options and select solution** which identifies and evaluates feasible and credible solutions to meet an identified need, followed by a selection process. This stage may partly overlap with the delivery stage. For example, if developers engage with the supply chain at the initial optioneering stage to reduce costs and to ensure deliverability of the project; and
- **Stage 4: Funding the delivery** which determines how the cost of the selected solution will be recovered and potentially considers the distribution impacts.

3.4 We consider each of the four stages in turn in the following subsections.

3.5 For each of the four stages of transmission planning, we set out, from a theoretical perspective, the key issues and challenges associated with transmission planning and the parameters policy makers typically use to design a planning framework. Finally, we present a summary of the key issues and design parameters of the transmission planning framework.

3.6 The fifth stage shown in Figure 3-1 above, the delivery and operation of the transmission solution falls outside of the scope of the transmission planning analysis set out in this report. This includes designing the procurement process (allocating risks to those best placed to manage them), delivering the solution, and ensuring accountability and appropriate incentives during operation. This stage involves a significant amount of risk, including: planning risk (i.e. the risk that the planning permissions and consents may not be obtained in time or for the required specification), construction risk (i.e. that the costs may escalate beyond the expected budgets – although this can be contractually managed), needs risk (i.e. the duration of the development and construction may take so long that the need for the asset disappears in the meantime) as well as operational risk (i.e. the risk that the asset will not be utilised efficiently and/or will cost more to operate than envisaged).

3.7 Nonetheless, we note that, as part of the project lifecycle, it is important to consider these arrangements in conjunction with the overall transmission plan. This is intended to ensure that the transmission plan is developed in view of realistic expectations on delivery and costs, as well as to promote sufficient incentives for the asset to be procured and delivered in line with the transmission plan.

A. Stage 1: Scenario development

3.8 As additional transmission investments connect future expected generation with future expected demand, an understanding on the expected future market conditions for generation and demand is required as a starting point when developing a transmission plan. Forward-looking scenarios are typically used as a key tool to map out the potential outcomes.

a) Key issues and challenges

3.9 It is challenging to forecast electricity generation and demand over a long time period.[27] Inevitably, this is because both generation and demand depend on many external variables, for example, wider macroeconomic variables such as GDP and population, as well as future technological advancements such as electric vehicles that are not yet realised.[28]

3.10 In addition to these factors, both generation and demand are susceptible to policy changes, such as changes to decarbonisation targets and/or subsidies to generation or energy efficiency.

3.11 The development of electricity market scenarios is typically subject to a wide consultation process led by the transmission planner (typically the SO). This allows for a wider range of reviews to be managed and considered. The range of views is likely to be widened if the scenarios cover a large region with multiple jurisdictions (e.g. the EU and Member States or the NEM and the five regions). This might result in significantly diverging scenarios (or sensitivities to the scenarios) to capture these views.

---

27 For demand forecasting, it is important to forecast both demand load (i.e. the amount of electricity needed at a single point in time) and electricity consumption (i.e. the amount of electricity consumed over a period of time). The need for transmission investments are driven more by the expected demand load.

28 It is particularly difficult to gauge the impact of emerging technology that could potential disrupt the market. For example, the unexpected reduction in cost of small-scale renewables generation over the last decade has led to a significant decrease in net demand from the transmission networks. Likewise, commentators have diverging views on the future potential of batteries and electric vehicles which may or may not materially impact forecasts.

3.12 In this stage, the relevant planning party articulates the range of medium-term or long-term market pathways. This would typically include, therefore, a variety of different paths:

- **Demand projections**, both in terms of total demand and peak demand, for the relevant region(s);
- **Supply projections**, in terms of the future generation mix (including new build as well as existing plant closure or mothballing assumptions); and
- **Input assumptions** such as fuel and carbon prices, as well as wider economic and policy factors such as renewable subsidies; and
- **Connections to neighbouring systems** which may change flows across the energy system.

3.13 Furthermore, because transmission conveys electricity from one place to another, scenario development may include forecasts, at a high-level, of the geographical distribution of future generation and demand.

3.14 These four groups of variables will need to be forecasted over a long period of time, which would inevitably lead to significant uncertainties.

3.15 Arguably, there is also a tension between what is 'likely to happen' and what 'policy-makers would like' which might cause misplaced assumptions when planning for transmission investments. For example, in Great Britain, Ofgem and National Grid relied on the 'Gone Green' scenario (which is the most optimistic scenario assuming high large-scale renewables growth to meet decarbonisation targets) for the transmission network price control which began in 2013. However, a year later, the expected amount of new connections was revised down from 33GW to 12 GW as a result from lower demand than expected.[29]

b) Design parameters

3.16 The main parameters, as described above, are the variables that need to be forecasted when developing forward-looking scenarios. In addition, the time horizon, their relative likelihood and the use of mandatory vs voluntary scenarios should also be considered. Each of these three aspects is discussed in turn below.

---

[29] Ofgem, RIIO Electricity Transmission Annual Report 2014-15, 10 December 2015, accessed at https://www.ofgem.gov.uk/sites/default/files/docs/riio_transmission_annual_report_2015_publish.pdf.

Time horizon

3.17 The first parameter is the time horizon considered for the scenarios, which presents a trade-off between a long-term and a short-term view.[30] A long-term scenario might provide more information to make better decisions, particularly as transmission investments are long-term and large-scale. However, the longer the time horizon, the greater the risk of the frequency and materiality of a forecast error.

3.18 Conversely, a short-term view might reduce the risk and impact of an error, but is likely to be less informative for investments with a long lead time and long lifetime during which benefits are expected to accrue.

Likelihood of different scenarios

3.19 The second design parameter determines how the scenarios are used in transmission planning to form a common understanding of the relative likelihood of different scenarios materialising in the future. Some options include:

- attributing probabilities to several scenarios to form a central probability-adjusted scenario;
- forming a single 'central scenario', with multiple sensitivities for consideration; and
- avoiding probabilities, but adopting a 'least regret' analysis when identifying a need and selecting the optimal solution against each scenario.

---

30 In conjunction to the time horizon, the frequency on updating the scenarios might also be important to account for any changes to forecasts as soon as possible. This is typically done every one or two years.

3.20 The first option provides a plurality of scenarios to encapsulate the full spectrum of what might be realistic, while the second option sets a prescriptive approach to forming a common understanding on the expected outlook. While attributing probabilities is challenging and potentially arbitrary, a prescriptive approach can lead to undesirable outcomes. For example, using a 'least-worst regret' approach when assessing potential options against a number of scenarios risks creating a 'false positive' outcome if one of the scenarios included in the assessment is very unlikely, but carries the risk of a very negative downside (i.e. high costs). In such a case, there is a risk that 'too much' investment is undertaken to avoid the high downside of a relatively unlikely scenario.

Mandatory vs voluntary scenarios

3.21 A third parameter to consider when developing scenarios is to determine whether the use of the scenarios by market participants in further transmission lifecycle stages should be mandatory or voluntary. The use of scenarios could range from a high-level informative and advisory tool used by the planner to a mandatory and necessary parameter required to obtain financing and/or regulatory approval. As an intermediate approach, it may be possible for a central authority to develop common forward-looking scenarios, which may be adjusted by prospective transmission asset developers to reflect project-specific or region-specific factors, subject to an appropriate regulatory or policy authority approval.

B. Stage 2: Identify need(s)

3.22 In this stage, a relevant authority (which may be the SO or the TO) performs an assessment to identify the future transmission needs.

3.23 There are two potential ways scenario development and the identification of needs can interact. First, transmission needs might be identified based on the forecasts in each scenario. In this case, transmission needs are likely to vary across each scenario. Second, a transmission need might be identified irrespective of scenarios, but the merits of potential investment are assessed against each scenario. For example, in GB, the potential need for interconnectors is identified first (by TO or third-party developers) before being evaluated in detail against each scenario.

3.24 Depending on the jurisdiction, this assessment can be based on a particular category of need (e.g. economic benefit of reduced future congestion costs, public policy or reliability need to address potential violations of relevant reliability criteria), and may also be articulated for a specific timeframe (e.g. congestion in seven years' time).

3.25 In addition, the assessment of the needs is typically based on a relatively granular assessment of the network, and the location of future demand and generation. For example, this may be done by focusing on specific network 'boundaries' where congestion on the transmission network might occur.

3.26 As part of this assessment, the relevant authority typically performs a forward-looking assessment of future levels of transmission congestion across all relevant system boundaries to identify congested areas and it may also assess the economic benefit (in terms of changes in wholesale power prices) of investments that connect different price zones.[31]

3.27 Wider policy drivers may also play a role in this process: for example, in GB, the rationale for using a separate investment test for interconnectors in GB stems from the policy-makers' desire to increase the level of interconnection to GB and to encourage private investment to deliver this. In the regulator's view, the Cap and Floor regime would give "*developers an incentive to identify efficient investment opportunities which are in consumers' interest*" and "*a level of certainty to developers without providing full consumer underwriting*".[32]

a) Key issues and challenges

3.28 Transmission planning typically supports the identification of the specific transmission network system need which could include:[33]

- **Network deepening**: this refers to transmission investments that serve as enhancements to the existing network. They do not necessarily have clear market benefits and "*involve physical upgrades of the facilities on the incumbent's existing network … physically intertwined with the incumbent TO's facilities*";[34] and

---

31 How the identified need is prescribed might differ across jurisdictions. In some cases, this may be prescribed as a need to resolve a boundary issue, while in others it may be a need to reinforce two specific points on the network.

32 Ofgem (2014) Decision to roll out a cap and floor regime to near-term electricity interconnectors.

33 This categorisation is based on the physical attributes of the transmission investment. Other jurisdictions follow different definitions, for example the US evaluate the ability for an investment to improve reliability, reduce congestion costs (economic efficiency), or enable public policy objectives.

34 Joskow and Tirole (2005) Merchant Transmission Investment.

- **Network expansion**: this refers to transmission investments that "*involve the construction of separate new links (including parallel links) that are not physically intertwined with the incumbent network except at the point at either end where they are interconnected*".[35]

3.29 Network expansion system needs can drive investments that take place within a zone where there are no wholesale electricity price differentials (i.e. 'intra-state' investments in the NEM context). Alternatively, these needs can drive investments between price zones where there are wholesale electricity price differentials (i.e. 'inter-state' investments in the NEM context). Three key examples of network expansion investments are:

- **Standard AC transmission lines**: these are transmission lines that connect two separate areas (e.g. face considerable congestion constraints) within a price zone;[36]
- **Interconnectors**: these are transmission lines that connect two different price zones and their construction allows the arbitrage of differences in wholesale prices of the two zones; and
- **Connection to a new large generator asset (e.g. renewable zone)**: this refers to transmission investments that connect from the incumbent network to new large generation assets. These have been used to connect to offshore wind farms in a European context but might also be used in the NEM to connect to onshore 'renewable zones'.

3.30 Figure 3-2 below illustrates some different circumstances in which transmission assets may be developed to meet identified transmission system needs, in the context of the NEM as a highly stylised example.

---

35 Ibid.

36 In the US, nodal pricing (as opposed to zonal pricing used in the NEM) means that onshore transmission networks connect two different price nodes and are therefore more akin to interconnectors.

Figure 3-2: Five broad types of transmission assets[37]

Transmission links within a single price zone may alleviate congestion or help connect new load…

1 Standard AC transmission line	▪ Standard AC line connecting points within the same power system and price area ▪ Typically serves to reinforce the existing backbone system to reflect demand/supply flows
2 HVDC link within system	▪ Connecting points within the same power system and price area ▪ DC link preferred to AC links over very long distances, or for subsea links
3 Link to remote renewable sources (offshore or onshore)	▪ Connecting very remote generation (e.g. offshore wind, or remote onshore solar PV) to the main grid ▪ Typically flows in a single-direction only

…while those connecting different price zones enable more efficient dispatch across the combined zone

4 AC interconnector	▪ These are typically onshore interconnectors between two price zones ▪ Examples include: QNI, Heywood
5 DC interconnector	▪ DC links are preferred to AC over very long distances and/or for subsea cables ▪ Examples include, Terranova, Basslink , Murraylink

Source: FTI-CL Energy analysis

3.31 As Figure 3-2 above indicates, one key differentiator between types of transmission investment is that they can be constructed either:[38]

- between different price zones ("inter-zonal") – for example between NSW and Queensland – known as interconnectors. These correspond to asset types 4 and 5 in Figure 3-2 above; or

---

37 Moreover, increasing trends in the development of renewables and interconnectors have led to greater consideration (although no realisation as yet) of "energy islands" which would combine different types of transmission assets, for example type 3 (links to remote renewables) and type 4 (AC interconnector). One example of a proposed development is an artificial island at Dogger Bank in the North Sea in Europe (https://www.tennet.eu/our-key-tasks/innovations/north-sea-wind-power-hub/).

38 This distinction is less relevant in electricity systems with locational marginal pricing on a nodal basis. This means that a spot price is set by the market for each node (a substation or switchyard where multiple transmission lines intersect) at each point in time. The transmission price of using the network between two nodes would therefore reflect the marginal price (including congestion and losses) and hence could typically be used to determine the net economic benefit of further transmission network investments.

- within the same price zones ("intra-zonal"), which correspond to asset types 1, 2 and 3 in Figure 3-2 above.

3.32 For network deepening investments, the identification of the investment need is often based on the existing network topology and the operational security targets (i.e. a reliability requirement). Operational security targets are usually either based on a Loss of Load Expectation ("LOLE") target[39] or some deterministic security criteria (such as N-1 or N-2 which refers to the number of failures the grid must be able to sustain).[40] Reliability requirements are therefore primarily technical in nature to 'deepen the networks' to maintain the relevant reliability criteria. While network deepening investments would ultimately have a monetisable economic impact on consumers, this investment need is often considered separately due to difficulties in quantifying the cost impact.

3.33 For network expansion investments for onshore lines within a price zone and interconnectors connecting two price zones, the identification of the need typically relies on price signals (i.e. an economic requirement). In energy markets such as the US, these investment needs are easier to identify due to a locational marginal price at each node.[41] In energy markets without price differentials, such as some European energy markets or the NEM's zonal market (i.e. investments within a price region), it is more challenging to identify an economic requirement, as it requires a quantification of the future congestion costs in the market. However, this can still be possible by observing the overall impact on the wholesale price (e.g. in the NEM, through changes in the Regional Reference Node price) and/or congestion payments (e.g. in GB, where explicit congestion payments are made).

---

39 For example, in the US, the reliability standard is set at the probability of an event occurring for one day for every 10 years.

40 For example, most of Europe sets a reliability standard based on the N-1 criterion. Transmission networks in GB follow an N-2 criterion.

41 Some interconnection in the US are built not to meet an economic requirement but to connect to distinct and separated energy systems (i.e. a public policy requirement).

3.34 For network expansion investments to connect large generation assets or 'zones', the identification of the need has been subject to ongoing challenges, particularly with renewables investment.[42] While greater investment in renewables generation is required to meet decarbonisation targets, large-scale REZ might be located far away from load centres. This presents a key coordination problem between generation and transmission – renewables developers may not be willing to take the risk of building new capacity unless there is certainty that the connecting transmission line will be built, and likewise the transmission investment may not be undertaken without certainty that sufficient generation assets will follow to make the investment efficient.

3.35 In this context, a distinction between proactive or reactive transmission investments can be made. Proactive transmission investments anticipate a transmission need (e.g. expected future large generation or consumption, or technical constraints), and may also induce further generation/demand as the asset would be built. Reactive transmission investments are built in response to an existing transmission need. While reactive transmission investments might be more cost-effective per project as they minimise the risk of asset stranding, this runs the risk of deterring new generation build or new demand connections. There may also be significant short-term operational costs incurred to manage the power system during the time it takes to build the required transmission investment.

b) Design parameters

3.36 Depending on the investment requirement, a transmission planning framework would need to set out:

- the parties to identify the need;
- the geographical reach; and
- the degree of planner's involvement.

42 These investments can also be undertaken to connect to large consumer developments (e.g. a steel factory).

Who should identify the need

3.37 There are various trade-offs depending on which party undertakes the coordinating role in identifying investment needs. Note that these coordinating roles are not mutually exclusive and can be undertaken by different parties for different types of assets. The options include:

- TO-led – the TO typically has a greater knowledge of the existing network and hence can identify investment needs more accurately. However, policy makers may have a concern that, while the TO is best placed to know the impact of alternative investments on its network or on connecting networks, particularly where the TO is a private company that is regulated, it is also potentially best placed to exploit its information advantage. A TO-led role might also lead to more frequent hold-ups or delays.
- Generation- or user-led – a prospective new generator or consumer would require a new transmission connection asset. For example, offshore transmission assets are identified and built in response to proposed offshore wind farms in GB.
- Third-party developer-led – a third-party developer could identify investment needs for interconnectors based on expected price differentials and thereby providing some competitive effects. However, it would be more challenging for third-party developers to acquire the necessary deep knowledge of existing transmission networks and congestion.
- SO-led – assuming the SO is independent (as is the case in the NEM and the US), the SO generally has an incentive not to overspend on transmission, but may not have as good an information set as the TO.[43] Hence, there is a potential asymmetric information issue where they have to rely on TOs' submissions that might be biased towards more investment. One potential approach to mitigate this issue is to enact legislation to ensure TOs provide accurate information or to financially incentivise them to do so.

[43] Arguably, SOs might be, by nature, risk averse, and therefore have an inherent bias towards conservative solutions such as 'tried and tested' methods and approaches. The SO might still have an incentive to overspend if there are stringent reliability requirements given its responsibility to balance the system. However, this potential issue is 'second order' to the misaligned incentive a TO might have.

- Regulator-led – the regulator would not have an incentive to overspend, but like the SO, would not have as good an information set as the TO. However, the regulator might not have as much information available as the SO (which is responsible for information provision and real-time operations) but could put in place mechanisms to ensure that accurate information would be provided by the relevant parties.
- Government-led – while Government tends to lack the technical expertise in networks, they are able to resolve coordination issues such as on generation and transmission investment for REZ. Hence, Government could direct transmission investments through a public policy requirement.
- Supra-national institutions – for cross-border investments, these institutions could play a role looking beyond a single jurisdiction to identify needs. This may also be relevant for countries with state and federal governments.

Geographical reach

3.38 The extent of the transmission planner relates to the geographic responsibility (or 'footprint') of the planner (local vs national) and it might affect how investment needs are identified.

3.39 A local transmission planner might have more in-depth knowledge of the existing network (such as an incumbent TO). Conversely, a national transmission planner could make decisions based on a wider whole-systems view taking into account the impact on different stakeholder groups in different locations. For example, a national transmission planner could consider the strategic impacts of transmission assets as well as multi-zonal investments (i.e. optimising energy flows across three states would require multiple transmission assets to be coordinated).[44]

Planner's involvement

3.40 The transmission planner role can vary from being relatively more or less deeply involved in coordinating market participants and driving particular outcomes.

[44] Examples include interconnector assets connecting Norway to Germany, through Denmark or potential transmission solutions spanning across New South Wales, South Australia and Victoria.

3.41 At one end of the spectrum, the transmission planner role may focus purely on providing participants with greater information and clarity. The planner's role is primarily advisory and participants have to make decisions based on the investment need. At the other end of the spectrum, the investment need identified by the planner has to be met and the planner's decisions are binding.

C. Stage 3: Identify options and select solution

3.42 Once the need has been identified, a subsequent stage is to identify which options might meet the need, and then select the preferred solution among them. The outcome of this stage is typically a formal transmission plan which informs all parties on which transmission assets, if any, to deliver.

3.43 There are four key steps in doing this:

- Exploring and collating potential solutions;
- Development of a list of options;
- Assessment and selection of the preferred option; and
- Holding the relevant party accountable for delivering the selected option.

3.44 Each of these steps is set out in turn below.

3.45 First, the system need is communicated by the transmission planner to the relevant parties who are invited to respond with their proposed solutions. The incumbent TOs are usually the key relevant parties, but proposals are often solicited from all parties that may be able to propose a viable solution, which may include non-TO parties.[45] The objective is to identify the range of credible options to be evaluated against each other. The solutions proposed may also include non-transmission solutions such as generation or demand-response, which would typically be provided by non-TO parties.

3.46 Second, a list of options is developed such that different options may be compared against each other for the transmission planner to identify the preferred one. This may include a process for including third parties' proposals in the list of options, and also might, in principle, include a competitive process for procuring these options. A key part of the planning framework is the process through which parties are incentivised appropriately to develop the most economically attractive options.

45 For financially-integrated TOs and SOs, there is typically more extensive regulatory oversight.

3.47 Third, the optimal option, if any, is selected. Typically, to do this, a methodology or a set of rules, is applied to the list of options to choose the preferred one. The specific approach differs significantly among jurisdictions, but often includes a form of technical screening (i.e. whether the option is feasible and delivers against the system need) and an economic assessment (such as a cost-benefit analysis and a risk analysis).

3.48 The authority responsible for developing the methodology and applying it may not always be the same party (for example, as in the NEM, the regulator could be responsible for designing the methodology, but the TOs then apply it in practice).

3.49 The choice of the preferred solution at this stage does not necessarily need to be a decision to construct a particular asset; other outcomes of the assessment can be for example to 'delay' or 'wait' until more information becomes available.

3.50 Fourth, a post-selection process may be put in place to hold the 'winner' accountable for the option they proposed. This may take the form of linking the regulated revenues to the original cost proposal, a dispute resolution process (whereby parties can challenge the decision on the preferred option), or an ex-post monitoring process of the costs and delivery timelines. Although this post-selection process is part of the 'delivery' phase of the project, the transmission planner and prospective developers need to understand the process to reflect any risks arising in the plan, and to be able to start managing those risks early on.

a) Key issues and challenges

3.51 The complexity of transmission investments, and the associated challenges in designing an appropriate investment test, arise from the information asymmetry among market participants, the imperfect information (to all participants) and coordination failure.

3.52 **Information asymmetry** (see Box 3-1 for further detail) refers to the different set of information available to different parties that are not readily disclosed to the party undertaking the investment test (or to third parties independently evaluating possible generation or transmission investments). This increases the risk of inefficient decisions being made.

3.53 **Imperfect information** refers to the lack of available information when carrying out an investment test and is closely related to the Stage 1 in which authorities seek to mitigate the imperfect information through scenario development. An investment test requires a series of scenarios and assumptions to produce an informed long-term view and these assumptions are typically more granular than those developed during scenario development (for example, specific circumstances of individual assets can be reflected in a more detailed set of assumptions underpinning the investment test). The lack of information is a significant source of potential 'market failure' that the investment test might help mitigate.[46]

3.54 **Coordination failure** refers to the lack of coordination between relevant parties, in particular between different regions, but also with respect to other asset types. This might result in inefficient decisions in the following ways:

- Creating a bias between intra-regional solutions and interconnectors, particularly as it is often easier for TSOs to reinforce their own networks rather than coordinate with neighbouring TSOs;[47]
- Lack of strategic oversight (e.g. to identify additional strategic benefits of coordinated interconnector or renewables development); and
- Greater risk of sub-optimal combined gas and electricity network solutions.[48]

---

46 The issues related to imperfect information are likely to become more challenging over time due to the uncertain supply side developments such as generation deployment (volume and location), rate of penetration of renewables (leading to a need for greater system flexibility in dispatch in order to manage rapid changes in net load) and increasing energy decentralisation. Similarly, growing demand-side developments such as load growth (e.g. from the deployment of electric vehicles and the impact of energy efficiency measures) contributes to the overall uncertainty.

47 There can be more complicated cases where three jurisdictions are involved and benefits to two non-adjacent TSOs can only be delivered by a new transmission line through a 'middle' TSO. To the extent that the 'middle' TSO does not benefit (and may face increased costs), socially optimal investments are very challenging to deliver. In these cases, a 'supra-national' view can enable socially efficient transmission investment.

48 For example, there may be a coordination issue between electricity and gas network development. In a typical illustrative example, an investment decision needs to be made regarding the siting of a gas-powered generator. The siting decision would in turn trigger either gas network development (to pipe the gas to the plant located close to the power demand centre), or power network development (where by power plant is sited close to the gas source, and power is transported to the demand centre).

Box 3-1: Sources of asymmetric information in investment tests

Information asymmetry could arise from various sources including:

- TOs tend to have private and more accurate information about their own network compared to other parties. As a result, policymakers may have a concern that while the transmission operator is best placed to know the impact of investments on its network or on connecting networks, it is also potentially best placed to exploit its information advantage.[49] Transmission planning frameworks and regulatory approaches more generally continually grapple with the design of a regime that overcomes the information asymmetry through a combination of information disclosure rules (the 'mandatory' approach) and incentives to reveal private information (the 'incentive' approach).
- Third-party prospective developers have considerably less knowledge about the existing network, constraints and future demand compared to the incumbent TOs, and may be at a disadvantage compared to the incumbent. There is also a further information asymmetry in regard to what generation will be shut down or started up within the planning horizon for the transmission investment. As generators are typically undertaken as merchant investments, they can be built and decommissioned at any time, making it difficult for a transmission planner to set a long-term view. While scenario development attempt to overcome this by articulating expected pathways for generator closures, these are imperfect and may not accurately capture the actual generator closures.
- As a result, given the partial (and imperfect) substitutability of generation and transmission investments in certain conditions, an unexpected entry or exit of generating capacity could materially affect the existing operation of the network and the future need for transmission investments.

b) Design parameters

3.55 The key design parameters for an investment test include the:

- process and application of investment tests;
- identification of options to reflect system needs; and

[49] The actual potential for leveraging any information advantage would depend on a number of factors including, *inter alia*, the ownership of the TOs and the way in which they are regulated and incentivised to use and disclose their information.

- design of the CBA.

3.56 Each of these parameters is discussed below in turn.

Process and application of investment tests

3.57 The role of undertaking investment tests is typically carried out by the system operator, the incumbent TO, or the regulator (or a mixture of the three, or, in some cases, the Government). However, as it is critical to be able to decide on the economically optimal solution (including third-party and non-transmission solutions), an independent arbiter may be needed to overcome private interests.

3.58 The choice of who is best placed to take on the role depends on a combination of:

- the historical context (i.e. who traditionally held the planning role as the market was liberalised);
- the availability of information and resources (i.e. who has the best access to reliable information and can act on that information with minimal conflicts of interest); and
- policy decisions (i.e. who is best placed to identify and select a solution that will deliver Government objectives).

3.59 Investment tests can also be undertaken by third parties (such as potential third-party owner/operators, developers of new generators or incumbent or neighbouring transmission operators) particularly with regards to interconnectors or connection assets which can be relatively distinct from the existing networks.

3.60 A significant amount of input into investment tests rely on information provided by the incumbent TO due to the depth of knowledge on the existing network. However, there is a potential risk that policy makers may perceive the incumbent TO to be incentivised to provide information that is biased towards greater transmission solutions so that it might benefit from the regulatory regime. As it is difficult for the party carrying out the investment test to verify this information, this gives rise to potential asymmetric information challenges.

3.61 To address this issue, the role of the regulator or the SO are as centralised bodies, *inter alia*, to extract as much information as possible from the TOs and third parties and, in so doing, to minimise the risk of inefficient investments being undertaken. The inefficiency could result either from:

- ‘too much’ investment being undertaken, resulting in network redundancy or excessive costs. This could be the case where the investment is undertaken within a price zone and is included in the owner’s RAB, enabling the owner to earn a regulated rate of return on such investment; or
- ‘too little’ investment being undertaken, which could in turn increase the cost of congestion on the network (in excess of the cost of the foregone transmission investment) ultimately paid for by the consumers. This could be the case where a particular TO seeks to protect a degree of market power (for example, by choosing not to increase the volume of further interconnection to a neighbouring price zone in order to increase the congestion revenues earned on the existing interconnectors).

3.62 The regulator or the SO can discharge this role in two ways:

- Direct involvement in the investment test; or
- Through a ‘design and administer’ approach, such as used by the AER, whereby the regulator simply sets the rules, but does not conduct the test.

3.63 As transmission investments typically require a long lead-time, the timeframe of investment tests is an important design parameter and, in particular, the frequency of any investment test (i.e. at what stages/how often a proponent can initiate a new investment test); and the duration of such test (i.e. how long it may take from the initial proposal to the final approval of the test by the relevant authority).

3.64 Additionally, the process of the investment tests often allows for a set-up of a disputes resolution process (which may in turn impact the timelines of the investment test). While policy makers do not typically intend for investment tests to lead to this outcome, it is a fall-back mechanism through which any disagreements on the CBA (or other matters) may be resolved. The presence of a disputes resolution process could enforce greater accountability but could result in greater delays in investment.

The identification of options to reflect system needs

3.65 The different network context (or system ‘need’) might require specific options. This can be illustrated by comparing the revenues that may or may not be earned by inter- and intra-zonal transmission assets.

3.66 First, assets that connect different price zones enable the transmission owners to export electricity from the low-price zone to the high price zone.[50] In doing so, the transmission asset generates an arbitrage profit – known as the congestion rent. Allocation of this rent, resulting from by an inter-zonal investment among market participants, may vary as follows:

- **Merchant.** The developer of a cable retains the congestion revenue over the asset's lifetime and uses it to fund the cost of the development and construction of the asset. This, in essence, is the merchant model of transmission (see ¶2.10 – ¶2.15 for a discussion of the role of merchant transmission investment).
- **Regulated.** Alternatively, the asset can be developed as a regulated, rather than merchant, investment. In this case the congestion revenues are subject to a revenue control mechanism. In this case any shortfalls in congestion revenues (relative to the costs of constructing the asset) are recovered from the generality of grid users and, conversely, any extra congestion revenues are returned to grid users.
- **Hybrid.** 'Blended' approaches that combine regulated and merchant features, such as the Cap and Floor regime in GB, are also possible.

3.67 Second, assets that connect two points within a single price zone (e.g. the first two transmission network asset types in Figure 3-2) cannot earn congestion rent – for the simple reason that there is no price differential to arbitrage. Hence, such assets can only be funded under some form of regulation and the costs recovered through a fee levied on users of the network. As a result, these investments are typically undertaken by incumbent TOs although third parties may also own and operate these assets.

3.68 Investment in transmission assets within a single price zone is driven primarily by the need to resolve intra-zonal congestion, but also by service quality, regulatory requirements and/or connections to new load.[51]

50 For example, AC and DC interconnectors (asset types 4 and 5) in Figure 3-2 above.

51 In the NEM, the AEMC and the Reliability Panel set the relevant guidelines and standards for the power network reliability. These may relate, for example, to the frequency operating standard and wider security and safety rules. Source: AEMC – Developing electricity guidelines and standards, accessed at: https://www.aemc.gov.au/our-work/developing-electricity-guidelines-and-standards.

3.69 In addition, in the NEM, intra-regional transmission investments could remove a congestion constraint in order to allow previously constrained off generators to generate more frequently and, in turn, lead to reductions in the electricity price (at the regional reference node) in that zone, at certain points in time, by enabling a lower marginal cost generator to produce.

3.70 In GB, the benefits of reduced congestion may include reduced compensation payments. This is because the GB approach to resolving congestion is different from the NEM. In GB, the market first clears "as if" there were no congestion constraints (a 'first best' outcome). The SO then clears the market with the system constraints taken into account, which typically leads to some generators being constrained 'on' and others 'off'. Both of these generators are compensated for their costs relative to the 'first best' outcome. [52]

3.71 <u>Third, connection of remote renewable generation</u>, or generation more generally, (Type 3 in Figure 3-2) can be seen as a standalone driver of investment, motivated by the resource availability for low-carbon generation. As set out in ¶2.2, some types of generators in some jurisdictions have limited discretion over their siting decisions, which may in turn, drive the need for specific transmission investments.

3.72 For each type of system need, there may be a range of non-transmission solutions that could potentially meet an identified need. Feasible and credible alternatives should be considered in an investment test in tandem with the transmission options to ensure that the most cost-effective solution can be selected. Non-transmission solutions might include facilitating new generation to be located at existing transmission networks, better utilisation of existing networks, demand-side and/or storage solutions, or distribution network solutions.

Design of the Cost-Benefit Analysis

3.73 Investment tests typically adopt a variant of cost-benefit analyses ("CBA"). These analyses compare the costs and benefits over a pre-determined period (often, but not always, over a period shorter than the whole life of the asset) with a discount rate applied to identify the net present value of the net benefits.

[52] The US approach is fundamentally different due to the use of locational pricing, which means that the SO is able to clear the market without any separate compensation for congestion (which is directly priced into the LMPs).

3.74 In general, the challenge therefore is to use a CBA to identify investments for which the present value of future benefits (which are uncertain due to imperfect foresight, and often estimated based on assumptions and probability-weighted scenarios) sufficiently exceeds the present value of expected costs of the investment (which typically tend to be somewhat more certain – although not always). A CBA could also allow potential investment proposals for the same need, including non-transmission solutions, to be ranked and compared. Different criteria can be used to select the preferred option, for example highest 'value-for-money', 'least-worst regret', or simply least-cost.

3.75 In some cases, where a transmission asset must be built (e.g. a connection line to an offshore wind farm), the methodology is primarily focussed on minimising cost recovery through a competitive tender process.

3.76 The range of costs assessed as part of a transmission investment test tends to be similar across jurisdictions. Costs include design and construction costs, operating and maintenance costs, tax and other non-controllable costs, and financing costs.

3.77 As explained above in Section 2.A, the benefits of a transmission investment include socio-economic welfare benefits, operational and strategic value benefits, some of which are considerably harder to quantify than costs. Each of these three categories is summarised below in turn:

- The socio-economic welfare value of transmission investments refers to the benefits and costs to different parties from the change in flows and prices as a result of the investment. This includes the distributional impact as different parties would be affected differently. A key question on this source of value is whether to consider total social welfare when evaluating an assessment, or to place greater importance on consumer welfare.[53]
- The operational value of transmission investments refers to the impact of investments on reliability and security of supply. This is driven mostly by an engineering view of the existing network, although some elements may be measurable due to changes in the electricity wholesale price.

[53] From a strict economic efficiency perspective, a cost-based approach would be used to assess the welfare impact from a socio-economic perspective. However, alternative approaches, such as price-based assessment can be used to carry out an assessment that is focused more on consumer welfare (i.e. the impact on the price changes that consumers are likely to experience as a result of the investment).

- The strategic value of transmission investments refers to the long-term strategic benefits of investments. This includes building a transmission line to incentivise greater renewables generation to 'cluster' around the asset, or to facilitate greater harmonisation between two distant areas.

3.78 Transmission planning frameworks differ in terms of which of the categories of benefits described above are included in the CBA, the importance attributed to them, and whether they are included in a quantitative or a qualitative manner. The decision on which of these benefits to include in the evaluation criteria could impact the outcome of the evaluation significantly.

3.79 The outcome of the CBA largely depends on how the CBA uses the selection of scenarios developed in Stage 1 (see ¶3.19). The approach to using these scenarios could be set by the SO or based on another pre-determined centralised process. It might also be based on a probability-adjusted scenario or a more deterministic calculation such as a 'least-regret analysis'.

3.80 Externalities[54] are not usually considered quantitatively in either the costs or benefits when assessing transmission investments due to the difficulty in calculating them. However, they may be considered qualitatively to form a holistic view on the proposed investment (e.g. Ofgem in assessing Strategic Wider Works with network companies).

54 Externalities may relate, for example, to the impact of the development of a transmission asset on the local economic (e.g. catering, housing), or to the price change impact in a particular zone (e.g. the construction of an interconnector may reduce the energy costs in a zone, which may in turn increase the competitiveness of energy-intensive industries relative to other regions).

3.81 The amount of information required to carry out a CBA means that there is a significant challenge with imperfect information which relates to uncertainty over the future.[55] Hence, investment tests may sometimes consider the option value and/or strategic value of proposed solutions. Option value refers to the value of utilising the investment when the market evolves over time (for example, an interconnector might be able to provide an additional source of flexibility if the market becomes more volatile). Strategic value refers to a wider set of values that are intended to achieve certain objectives, for example, transmission assets to facilitate greater 'harmonisation' between states or to facilitate greater renewables investment to meet decarbonisation targets. In the NEM context, this might relate to the value of designing a transmission network that is resilient to extreme weather events such as cyclones and bushfires.[56]

3.82 To calculate the net present value from the CBA, a discount rate is usually applied. There is no consensus on the appropriate approach and quantum for the discount rate. Possible options include a 'social discount rate', different discount rates on a case-by-case basis and a comparable private sector discount rate among others.[57] For competitive tenders, bidders may be able to select their own discount rate to reflect their risk profile and financing structure.

55 For example, over-sizing a given transmission line that is developed to connect the main grid to a new source of generation may provide an option value to later use the same line to connect additional plants in the region.

56 The Finkel review noted that in the NEM, the *"power system will need to be robust"* to *"emerging threats"* such as extreme weather events. As an example, AEMO discounted one option for an interconnector because it was adjacent to an existing interconnector which means that both would be susceptible to the same weather risk (e.g. a bushfire). Commonwealth of Australia, Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, June 2017 (also known as "the Finkel Review"), pp. 32 - 33.

57 The social discount rate aims to capture the time value to society of costs and benefits. It is the rate at which society values the present compared to the future, and considers the time preference of consumption and the wealth effect of expected growth in per capital consumption. In GB, it is labelled as the HM Treasury STPR, and has been set at 3.5% in real terms since 2003.

D. Stage 4: Funding the delivery

3.83 After the preferred solution is delivered by a designated party (e.g. a TO or, in some cases, a third-party developer), a further stage involves determining the arrangements to fund the delivery of the transmission investment. This includes the approach to cost recovery, cost allocation and other incentive arrangements for the delivery of the transmission investment.

3.84 While this stage occurs after the transmission plan is formed, the approach to funding the delivery plays a key role to inform the transmission planning framework in the first instance.

3.85 The **cost recovery** of transmission investments refers to the approach to determining the revenue profile for the investor and the procurement approach, taking into account the risk of the investment. Different approaches are possible, including:

- **Recovery through connection charges.** New generators typically pay connection charges to connect to the transmission system. There are two broad types of connection charges – shallow vs deep charges. Shallow charges cover the cost of connecting to a point (typically the nearest point) to the transmission network. Deep charges cover the shallow charges plus additional network costs 'triggered' by the investment, including network reinforcements.

- **Recovery through use of system charges.** For transmission investments that are not recovered from a particular generator, costs are typically recovered through the generality of grid users (both generators and demand users), by regulating the revenues that the investor can recover through the use of system charges. This approach is often used for investments undertaken by incumbent TOs (or for example offshore wind transmission operators in GB), when relating to within-single-price-zone investments.

- **Direct recovery (merchant investments).** For investments that connect different price zones, the investor may be able to retain sufficient revenues from operating the asset such that costs do not need to be socialised with the generality of grid users ('merchant' investments). This approach can (but does not have to) be used for interconnector development.

- **Other variants.** There are also other variants of cost recovery mechanisms which may include competitive tendering, or which determine some form of risk-sharing mechanism (such as a cap and/or floor on the socialisation of costs).

3.86 Policy makers may choose to apply a cost recovery mechanism that is appropriate, cost-effective and does not lead to any unintended consequences (such as undermining the competitive procurement of assets).

3.87 **Cost allocation** refers to how the costs of the transmission investment are allocated among market participants in the different regions affected by the investment. Similar to the cost recovery issues discussed above, it is important to distinguish between investments that take place within or between price zones.

- Within price zones, the cost of transmission assets may simply be smeared across transmission grid users through charges on load or on generators, with only limited considerations given to different categories of system users. Grid charges may (but do not have to) have a locational element (for example, to incentivise new generation to be built in proximity to demand centres), which creates some cost allocation impact among different market participants.
- Between price zones (or nodes), the cost allocation approach may seek to allocate the risk and rewards appropriately among relevant parties to account for the distribution effects of an investment. The distribution effects can take place both between the connecting price zones (as wholesale prices will typically increase in one zone and decrease in the other zone as a result of the investment), but also within each of the connecting zones (as producers and consumers are impacted differently and typically in an opposite direction to each other).

3.88 Between price zones, the cost allocation approach may seek to ensure that the costs of an investment are placed on the party (or parties) that benefits from the investment and that the risks of an investment are allocated to those most incentivised (and therefore best placed) to manage them. This is often referred to as the 'beneficiary-pays principle'.[58] We explore in this report that although this is the preferred principle in theory, its practical application in the context of transmission planning is often challenging.

3.89 During the operation of the asset, the allocation of benefits remains a key design issue for the planning framework. For example, any congestion revenue earned by an interconnector linking two different price zones, or any associated welfare impacts (such as changes to consumer and producer surplus at either end of the interconnector) may need to be monitored and potentially re-allocated among parties over the life of the asset.

---

58 Hogan (January 2018) A Primer on Transmission Benefits and Cost Allocation.

a) *Key issues and challenges*

3.90 The cost allocation approach may seek to address 'winners and losers' created from the investment as well as potential 'free-rider' problems where participants take advantage of the new investment. In general, there are two broad approaches to cost allocation – the beneficiary-pays principle and cost socialisation:

- The beneficiary-pays approach is based on the principle that the costs and risks of an investment should be allocated commensurately to those most incentivised (and therefore best placed) to manage them.[59] However, the application of this principle can, in practice, be complex (for example as the quantum of benefits is unknown on an ex ante basis).
- The cost socialisation principle, on the other hand, is commonly adopted due to the ease and transparency of the approach (even though the benefits are unlikely to be evenly dispersed among the payers). It also provides value when the investment is required for strategic purposes (such as providing greater 'option value') or if the investment will produce significant positive wider unquantifiable externalities (such as large renewable energy zones).

3.91 The costs of transmission investments that take place within a single price zone typically follow the cost socialisation principle.

3.92 When the costs of transmission investments take place between price zones, either of two approaches (or a combination of both) can be used:

- **Full socialisation.** Connecting TSOs may agree to socialise the costs across all grid users (e.g. by increasing the use of system charges at both ends of the interconnector).
- **Full beneficiary-pays approach.** Connecting TSOs may agree on a specific allocation of costs to individual grid users who benefit from the investment, and develop a detailed beneficiary-pays cost allocation mechanism (either based on actual benefits, or based on the benefits expected as at the time of making the investment). In addition, compensation mechanisms for the 'losers' from the investment may also be incorporated.

59 Hogan (January 2018) A Primer on Transmission Benefits and Cost Allocation.

- **Mixed approach.** Connecting TSOs may agree that one of the two regions is the net beneficiary of the investment, such that costs would be allocated to one region only (and then socialised among all grid users in that region). Inter-TSO compensation schemes may also possible that allow regions to compensate each other (while retaining cost socialisation within the individual regions).

3.93 Additionally, once the asset has been built, it is important for there to be an appropriate degree of **accountability and monitoring** of operating costs to ensure that any cost-overruns (or underruns) are appropriately allocated.

b) Design parameters

3.94 The SO or regulator plays the key role in designing and implementing the funding approach. This may be designed differently for different types of assets. The regulatory regime should also support competition, stimulate innovation, balance flexibility/robustness in the face of uncertainty and provide credibility and assurance to investors.

3.95 Three design parameters as part of the funding approach need to be considered when designing the transmission planning framework. These are:

- First, **who should build and operate** the transmission asset. While the incumbent operator might have an advantage due to the inherent knowledge of the existing network, some transmission assets that are separable can be built and operated by third-parties. Third-party ownership may be feasible for specific types of assets (particularly for DC interconnectors which do not require deep knowledge of existing incumbent networks). There is also scope for third-party ownership for long-distance and distinct network expansion assets within a price zone.[60] These transmission assets can be procured through competitive processes which might lead to lower cost outcomes.

60 For example, in GB, Ofgem has been considering competitive tender arrangements for new, large and separable onshore networks known as Competitively Appointed Transmission Owners ("CATOs").

- Second, **who should pay** for the transmission asset. The cost of a transmission investment can be paid by either generators or developers (which in turn are levied to some or all consumers through transmission tariffs).[61] While consumers ultimately pay for the cost, the method of payment has distributional effects.
- Third, **which party should bear the risks** associated with the transmission asset. Generally accepted good regulatory practice is that risks are allocated to the party best placed to manage them. In a transmission lifecycle, there are various types of risks which may or may not be allocated to the same party. These risks include planning, design, financing, constructing, owning and operating risks. The choice on which party should bear each type of risk depends on the design parameters above (for example a party that builds an asset should be incentivised to minimise cost with minimal delays, and a party that operates an asset should be incentivised to maintain availability). There is also often a trade-off between how much risk a party should take versus the risk a consumer should take (through higher transmission tariffs).

3.96 The **cost recovery** approach should determine the type of funding arrangement (e.g. a fully regulated regime based on a bottom-up cost analysis or a partial regulation by setting a cap and/or floor).[62] The choice of the funding arrangement might be driven by the physical characteristic of the asset and the wider market design. For example, the presence of clear price signals might mean a simple cap and floor may be seen as appropriate for an interconnector relying on price arbitrage. Additionally, the regulatory regime should ensure that the level of risk borne by each party should be commensurate with the rewards.

---

[61] In the NEM, generators do not pay use of system charges although they pay connection charges. Transmission use of system charges are levied on direct users and DNSPs. AEMC (2017) 'Fact Sheet: How transmission frameworks work in the NEM'.

[62] See ¶2.10 – ¶2.15 for the challenges to merchant transmission investments.

3.97 The transmission planner could also consider user-commitment rules, i.e. requiring generators to fund a portion of the network costs upfront. This could help resolve some of the coordination issues between generation and transmission. Generators can contribute to the cost either by an *ex-ante* financial commitment, or through paying an upfront portion of transmission charges.[63]

3.98 **Cost allocation** mechanisms for transmission investments that take place between price zones have a key role in mitigating the negative effects on some parties. In theory, as long as the costs were allocated, proportionately, to the beneficiaries of the investment (and provided the NPV of the welfare impact was positive), then all parties could be made better off as a result of such investment. However, as explained in ¶3.90, the practical challenges in identifying and allocating the benefits are significant and often prohibitive (in particular on an ex-ante basis). Examples of approaches to partially overcome this challenge include:

- using a portion of congestion rent to reduce the transmission charges on negatively-affected parties (i.e. passing through some of the congestion rent earned by the TSO to lower transmission charged levied on consumers in the exporting region);[64] or
- cross-border arrangements between neighbouring TSOs aiming to compensate each other for hosting 'transit' flows (the European inter-TSO compensation scheme is an example of this approach being used in practice, see ¶4.62).

63 In some jurisdictions with capacity markets, generators can only receive capacity payments if they have firm access to transmission capacity. This may be another driver for jurisdictions with capacity markets to incentivise generators to fund transmission investments.

64 This approach of cost allocation, while broadly accepted as a useful approach to mitigate negative cost distribution effects, can be complex. The difficulty in predicting flows across the transmission asset over a certain period means that it is different to commit an ex-ante reduction in transmission tariffs. One option is to implement an ex-post adjustment based on actual flows at various intervals over the life of the asset; however, it is unclear if this might result in unintended distortionary incentives. Another option would be to allocate costs on the expectation of the benefits distribution that formed the basis of the investment decision itself (regardless of how the benefits ended up being distributed).

3.99 On **accountability and monitoring** of the delivery of the investment, the challenges presented can be addressed by central authority, typically a regulator, who would determine the framework for a party to operate the transmission asset as well as the rules and incentives to ensure the transmission asset is operated as efficiently as possible.[65]

3.100 Inevitably, the costs of the projects tend to differ from the initial expectations (for example due to a change in their size, technology, routing or supplier costs). Some of those changes may be economically efficient (e.g. increase in costs due to an increase in the scale of the asset due to an increased need for the asset), but others may not be.

3.101 To the extent that the authority seeks to incentivise the developer to only incur efficient economic costs, it may be appropriate to complement the ex-ante (and highly uncertain) assessment with an ex-post review of the costs, to verify whether (or to what extent) those costs have been incurred efficiently. This is referred to as an ex-post 'efficiency review test'.

3.102 In addition to an ex-post efficient review test, incentives must be designed to deliver efficiency. The incentives to be considered include both an availability incentive, as well as for open access.

Box 3-2: Incumbent TOs vs third-party developers to design and deliver solutions

To design and deliver transmission investment, one key design element is to identify who is best placed to manage the risks of a transmission investment – typically either the incumbent TOs or third-party developers.

Transmission investment that relates to physical upgrades of the incumbent TO's network, maintenance, or other investments that cannot be easily

[65] Additional incentives can also be placed on the SO in its role on balancing the system. These incentives are typically linked to the procurement and dispatch of ancillary services to utilise generation and transmission assets more efficiently. Incentives can either be financial, management or reputational incentives with financial incentives more common for for-profit SOs and other types of incentives for not-for-profit SOs.

identified/separated from the rest of the network are typically undertaken by the existing owners of the network.[66] Third parties are not well placed to deliver these investments efficiently for the following reasons:

- **Accountability.** There might be less accountability due to the allocation of roles and responsibilities at the interface between assets owned by different parties.
- **Practical challenges**. It is impractical to design suitable contracts for third parties to deliver physical assets deeply embedded ('meshed') within a much larger network, such that the contracts would achieve appropriate incentives for an optimal development, maintenance and responsibility for the asset. The allocation of capacity rights between the incumbent and the developer of 'deepened' capacity is also likely to be complex.
- **Information asymmetry.** Third-party prospective developers have considerably less knowledge about the existing network, constraints and future demand compared to the incumbent TOs. They are therefore poorly placed to propose and implement efficient investments.
- **No capturable economic profit**. Some investments undertaken by the TOs relate to mandatory investments to maintain certain power quality, frequency and other technical parameters, and therefore do not deliver identifiable monetary benefits to the owner. Third-party developers, to the extent that they would not be able to identify and capture the economic profit resulting from their investment, would not be in a position to undertake this type of investments.

As a practical matter, it therefore appears that certain types of investments are most efficiently undertaken by the incumbent TOs. However, such investments also face practical challenges and require a careful design of the regulatory arrangements to overcome the following issues:

- **Monopoly rent**. Economic theory shows that for unregulated monopolies, which are free to set their prices, there will be a failure to maximise social welfare; prices will be set too high and this will extract too much rent from consumers. This means that although unregulated monopolies will benefit

66 Joskow and Tirole (2005) refer to these types of investments as 'network deepening'. They set out several examples of this type of investments, including: "*adding capacitor banks, phase shifters, reconductoring existing transmission links, new communications and relay equipment spread around the network to increase the speed with which the SO can respond to sudden equipment outages and relax contingency constraints*" (pp 238).

from not being regulated, consumers will be worse off. Moreover, total social welfare, which is usually defined in economic terms as the sum of monopoly's profits plus consumer surplus (i.e. the value that consumers derive from consuming the good or service), is lower when monopolies' pricing is set freely. Economic regulation therefore focuses on addressing the optimal allocation of costs and benefits between different parties (for the risk incurred) and setting the price that monopolies are allowed to charge consumers for the provision of their goods or services.

- **Information asymmetry.** The TO has a private and superior information set about its own network compared to all other parties in the market. As a result, while the TNSP is best placed to know the optimal investments required on its network, it is also best placed to exploit its information advantage. Regulatory regimes continually grapple with the design of a regime that overcomes the information asymmetry through a combination of information disclosure rules (the 'mandatory' approach) and incentives to reveal private information (the 'incentive' approach).

Therefore, the transmission planner or the regulator will need to determine which party is best placed to design and deliver the solution (in some procurement models, the design, build and operate phases can be separated). To an extent, these issues are lessened when the transmission investment is new, separable, and large.

E. Summary of key design parameters to address transmission investment challenges

3.103 The design of a transmission planning framework needs to select appropriate design parameters to address the issues and challenges highlighted above. This is summarised, from a theoretical perspective, in Table 3-1 below. We explore the actual international experience of transmission planning and the different approaches to meeting these challenges in Section 4.

Table 3-1: Summary of key design parameters to address transmission investment challenges

	Key issues and challenges	Design parameters
Stage 1: Scenario development	▪ Difficult to forecast (uncertain market, policy and multiple stakeholder views) ▪ Imperfect coordination among generation and transmission developers ▪ Overreliance on deterministic scenarios may lead to significant over- or underinvestment	▪ Time horizon ▪ Approach to using scenarios (attribute probabilities, one set of central scenarios, least-regret analysis) ▪ 'Weight' of scenarios in investment decision-making (mandatory vs advisory)
Stage 2: Identify need(s)	▪ Rapidly changing world/increasing uncertainty of need (where, when, how much) ▪ Different drivers of transmission investment (network deepening vs intra-regional/interregional/REZ expansion) ▪ Coordinating generation and transmission investments (especially with REZ) ▪ Proactive vs reactive investment	▪ Multiple parties able to identify system needs (TO, generation/user, third-party developer, SO, regulator, Government) ▪ Extent of transmission planner (local vs national, types of investments) ▪ Depth of transmission planner role (advisory vs binding) ▪ Coordinating REZ generation and transmission (no coordination, top-down mandate, bottom-up cost recovery, hybrid)
Stage 3: Identify options and select solution	▪ Reflecting different system needs ▪ Selecting appropriate sources of 'value' or benefits for the CBA assessment. Monetary benefits often incomplete, but additional security of supply and strategic benefits hard to measure ▪ Uncertainty on costs and benefits (even more than costs) and addressing this through discounting and scenario analysis	▪ Process and application of investment tests (roles of third-parties, TO, SO and regulator, dispute resolution process) ▪ Design of the CBA (use of scenarios, inclusion of difficult-to-measure impacts such as option value, discount rate)
Stage 4: Funding the delivery	▪ Risk and responsibility allocation among parties ▪ The appropriate cost recovery approach that is commensurate to the risk incurred ▪ The approach to cost allocation (beneficiaries-pay vs cost socialization principle) and other distributional impacts ▪ Accountability and monitoring of costs ▪ Incentives to provide access, avoid undue market power and increase availability	▪ The type of cost recovery approach or regulatory regime (fully-regulated, partially-regulated or merchant models) ▪ The ability of generators to fund a portion of network costs ▪ Cost allocation arrangements and the resolution of distributional impacts (e.g. cross-border compensation) ▪ Role of the regulator in monitoring (+ ex-post efficiency review) ▪ Availability incentives/rules

4. International case studies on transmission planning

4.1 This section sets out a summary of selected international precedents for transmission planning practice, focusing on the rules and tools used by the policy makers, and the asset options considered throughout the transmission planning process. The full details of each of the case studies presented in this section can be found in Appendix 1. This section is structure as follows:

- In Section A, we set out the key aspects of transmission planning following the key stages of transmission solution development.
- In Section B, we summarise and compare the US ISO models to the European model and highlight their key characteristics.

A. Transmission planning: international evidence

4.2 We have examined transmission planning in four key regions:

- Great Britain: where transmission planning is led by the SO and approved by the regulator depending on the asset type, and where the SO is independent in some areas (Scotland) but not in others (England and Wales);
- United States (NYISO and PJM in particular): where transmission planning led by an independent system operator ("ISO"), sometimes across multiple states;[67]
- Europe: as a 'supra-national' planner intended to coordinate cross-border transmission investments;[68] and

[67] In this report, we refer to the 'United States' case studies as a shorthand for the selected jurisdictions that we have reviewed, notably PJM and NYISO. This analysis should not be interpreted as relating to all of the jurisdictions across the US territory, as they may differ from those included in the analysis.

[68] In this report we refer to 'Europe' case studies as a shorthand for the 28 Member State European Union (i.e. prior to Brexit). We also include Great Britain and Germany as two case studies reflecting the approaches of two of the European Union Member States.

- Germany: where there are four transmission system operators (with transmission operation and system operation as a single entity), each leading on transmission planning in separate regions.

4.3 In GB, we have focussed on four transmission planning processes:

- The Strategic Wider Works ("SWW") process which allows the incumbent GB TOs to propose large transmission investments;
- The Network Options Assessment ("NOA") which is run by National Grid annually to select preferred transmission investment options to meet identified needs. The recommendations of the NOA process are non-binding;
- The Offshore Transmission Operator ("OFTO") process is a competitive tender to assign a transmission operator and connect offshore wind farms to the GB network; and
- Interconnectors between GB and Europe are proposed and developed by third parties, and are subject to Ofgem's Cap and Floor regime.

4.4 In the US, we have considered on the transmission planning process in:

- NYISO;
- PJM;
- Specific case studies focusing on interregional coordination;[69] and
- Specific case studies on renewables generation and transmission coordination.

4.5 In Europe, we have focused on transmission planning processes of ENTSO-E, which plays an important coordination role of national TSOs and oversees the transmission planning assessments for cross-border transmission investments to develop the biennial Ten-Year Network Development Plan ("TYNDP").

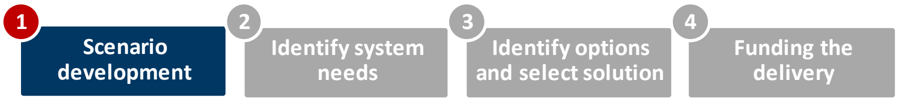
4.6 In Germany, we have considered the four TSOs which, in collaboration with (and oversight from) the regulator Bundesnetzagentur ("BNetzA"), produces the German Grid Development Plan ("GDP") which plans the onshore networks.

---

[69] In the US, as discussed in FN36, nodal pricing means that any onshore transmission line that connects two different price nodes can be thought of as an "interconnector", even lines within states, while, in practice, "interconnectors" in Europe and the NEM tend to refer to transmission lines connecting different countries or different states. Lines that cross ISO boundaries (e.g. a line connecting the PJM and NYISO networks) in the US are therefore referred to as "interregional" lines.

4.7 The remainder of this section sets out the key features of transmission planning in the selected jurisdictions. Each of the subsections covers one of the main stages of the process: development of scenarios, identification of system needs, selection of a preferred solution, and the funding of the delivery of a solution.

Stage 1: Scenario development



4.8 Long-term planning scenarios develop a view of the expected generation and demand evolution over a period of time. This allows them to be used as a mechanism to coordinate the baseline views of multiple market players in terms of expectations of future market outcomes. The scenarios are typically developed by the SO (or SOs in Europe as ENTSO-E), with some jurisdictions taking input from other parties or explicitly considering a broad range of stakeholder views.

4.9 Long-term scenarios can be used differently across jurisdictions – in some cases they are developed with the intention of only playing an advisory and coordination role, but in other cases authorities may require specific long-term scenarios to be used by market participants when assessing the economic merits of a particular transmission option.

Great Britain

4.10 In GB, the National Grid SO annually publishes Future Energy Scenarios (FES) for the next *circa* 40 years (the recent 2018 FES includes forecasts up to 2050). FES sets out four different scenarios, or states of the world, that represent different combinations of decentralisation (extent to which assets are linked to local networks and processes) and decarbonisation (carbon emissions reduction and increasing sustainability).[70] There are no probabilities attached to these scenarios as they are intended to represent an envelope of plausible outcomes for the economy.

4.11 The FES development process undertaken by National Grid is described below and summarised in Figure 4-1.[71] This process is undertaken annually to ensure that the FES are reflective of the current energy landscape.

70 National Grid, FES 2018.

71 National Grid, Stakeholder Feedback Document Future Energy Scenarios, January 2018.

Figure 4-1: FES development and engagement lifecycle

Source: National Grid.
Note: Bi-lateral meetings with stakeholders occur throughout the year.[72]

4.12 At a high level, the main three stages of the process include stakeholder engagement, data and intelligence gathering and, finally, high-level scenario creation, modelling and analysis.

- Stage 1: National Grid **engage with stakeholders**, such as industry experts, consumer groups and business, to gather feedback on suggested inputs that will inform the basis of its analysis. Following the engagement process, National Grid creates a scenario framework that details the assumptions and levers to be used. The framework includes scenario worlds, which illustrate pathways to the future and describe assumptions about the political, economic, social, technological and environmental landscapes.
- Stage 2: National Grid **gathers data and intelligence** that will be used within the scenario framework.
- Stage 3: National Grid undertakes **analysis** by applying levers to the assumptions, and feeding them into their various models. The models produce scenario outputs that are included in the FES publication.

72 National Grid (January 2018) Stakeholder Feedback Document – Future Energy Scenarios, pp. 25.

4.13 In addition to the above, National Grid continually engages with stakeholders through written communications, surveys and a number of other methods. During 2017, National Grid engaged with a total of 430 organisations, including 187 in the energy industry, 77 customers, as well as a variety of small businesses, supply chain participants, investors, media, communities, consumers groups and the regulator.

4.14 The FES play different roles in the cost benefit analyses of the various GB transmission assets, but often represent 'core' scenarios, with additional sensitivities developed to stress test project viability beyond the core scenario envelope.

- The NOA process makes explicit use of the FES to perform its 'Least-Worst Regret' analysis of outcomes (considering the least bad outcome across all four scenarios);
- The assessment of GB interconnectors is more flexible, as both developers and Ofgem can tailor the scenarios as appropriate to the particular assessment being carried out (i.e. they are not explicitly required to use the FES scenarios). However, the FES scenarios are often used to determine a baseline set of assumptions, from which any divergence is justified by the entity running the scenario.
- The SWW and OFTO approaches explicitly rely on the FES scenarios.

United States

4.15 In the US, long-term scenarios are used more explicitly in transmission planning, as the SOs that undertake the forecast also tend to be the parties responsible for conducting the cost benefit analyses for investment tests. However, they are not centrally determined; each SO performs its own individual forecasts and studies to estimate future energy outcomes for the purposes of its transmission planning. Moreover, scenario development is often in the form of a single base case, with ad hoc sensitivity analysis when appropriate. These base case forecasts are typically formed with input from, or are reviewed by, a variety of stakeholders. This can include various state authorities, utilities, and TOs.

4.16 Due to the more active role of SOs in the US (relative to GB, discussed above) and the fact that they run the cost benefit analysis with only technical input from solution proponents, the long-term scenarios carry more importance in the US than in GB. The ISOs in the US typically mandate that specific long-term scenarios be used in identifying and assessing potential transmission options, while this is not the case in GB.

Europe

4.17 In Europe, the ENTSO-E develops three TYNDP scenarios, which are developed as a joint planning exercise between ENTSO-E, ENTSO-G (the "ENTSOs") and member TSOs.[73]

4.18 The three scenarios are:[74]

- **Sustainable Transition**: this scenario assumes targets are reached through national regulation, emission trading schemes and subsidies.
- **Distributed Generation**: this scenario assumes high decentralisation, i.e. considerable small-scale generation, batteries and fuel-switching and 'active consumers'.
- **Global Climate Action**: this scenario assumes a significant large-scale renewables development in both electricity and gas sectors towards global decarbonisation.

4.19 The ENTSO-E scenarios are designed to be representative of at least two of the following time horizons:[75]

- **Mid-term** (5 to 10 years): Mid-term analysis should be based on forecasts for this period, and may be based on long-term analysis from previous publications of the TYNDP;
- **Long-term** (10 to 20 years): the ENTSO-E scenarios developed will lie in this period, and the realised future pathway should fall in the range of these scenarios with a high level of certainty; and
- **Very long-term** (30 to 40 years): should be based on the ENTSO-E 2050-reports.

[73] From 2018 onwards, ENTSO-E and ENTSO-G have begun to jointly develop the TYNDP scenarios with the objective of creating a consistent view of the possible evolution of the energy system in Europe.

[74] An extra scenario has been developed by the European Commission. This scenario assumes 2030 targets being met, but includes an energy efficiency target of 30%.

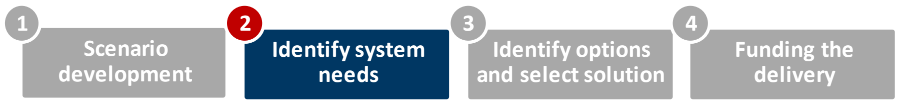
[75] ENTSO-E, Guideline for Cost Benefit Analysis of Grid Development Projects, Draft for public consultation, 25 April – 31 May.

4.20 These scenarios are used in assessing the merits of cross-border investments, such as interconnectors – for example, in deciding which of potential investments should be awarded a ‘Project of Common Interest Status’, each of the four Visions is considered and evaluated.

Germany

4.21 The TYNDP scenarios developed at the European level do not translate into country-level scenarios. For example, the four German TSOs are responsible for jointly developing four scenarios which are reviewed and approved by BNetzA. The 2017 scenarios consider the level of innovation, and rate of transformation towards a secure, low-carbon, affordable energy sector.

Stage 2: Identify need(s)



4.22 Most jurisdictions rely on a coordinated effort from several parties to identify system needs. The SO tends to take on the lead role in identifying where transmission investments might be required (i.e. the system need). However, Government, regulators, or third parties (via public consultation) can also identify system needs that are more strategic from a public policy perspective. TOs can also identify system needs through the price control process with the regulator up to a certain size threshold. Some TOs are obligated to build a connecting transmission line which means that system needs are generation-led. This may involve several processes depending on the different types of transmission investment requirements.

Great Britain

4.23 In GB, the TOs, SO and offshore wind generators are each responsible for identifying a particular type of system need. These are:

- Smaller-scale transmission investments which are known as wider works outputs, are proposed by TOs (and the regulator provides an allowance, subject to uncertainty mechanisms and delivery of the outputs) as part of the standard price control process.

- Large, uncertain onshore transmission requirements are identified by the TO through the SWW process. SWW reflects the uncertain need to make a significant transmission investment outside those provided for in its standard price control. This jurisdiction is limited to the area under the control of the given TO.[76]
- System needs under the NOA process, which relates to projects across system boundaries (defined by the SO), are identified by the SO, which is able to propose needs for the whole of GB. Unlike SWW, these are non-binding.
- The need for OFTO investment is led by the developer of the offshore windfarm as by building the offshore wind farm, as Ofgem is required to connect it to the onshore network.

4.24 In GB, the development of interconnectors is market-driven; they may be merchant or regulated under a cap and floor regime set by Ofgem. Rather, the prospective interconnector developers assess a 'need' based on their assessment of expected future arbitrage revenues from the asset. Thus, there is no formal process to identify a 'need' for this type of investment need. The NOA, however, does include a view on the 'optimal' volume of interconnection in GB, but this is in a purely advisory role and does not comment on specific projects.

United States

4.25 In both NYISO and PJM, reliability and economic needs for transmission are identified by the ISO, based on the scenario development approach described in the previous sub-section. Each ISO's authority is limited to its region, and their decisions are binding. Hence, NYISO may only recommend system needs for the State of New York, while PJM may only recommend system needs for its control area.[77] Additionally, in the US, state regulators may propose specific transmission projects for evaluation by the ISOs, and may work with ISO through the transmission planning and decision process.

---

76 National Grid Electricity Transmission plc covers England and Wales, while Scottish Hydro Electric Transmission plc and Scottish Power Transmission Ltd cover Scotland. The cost thresholds that differentiate 'smaller' and SWW investments also vary across the three regions.

77 These are the states of: Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia, and the District of Columbia.

4.26 Transmission investments required to meet so-called 'public policy' needs are usually identified by a party other than the ISO:

- In the NYISO area, the New York Public Service Commission ("NYPSC"), a local utilities regulator, is responsible for identifying public policy needs.
- In the PJM area, entities authorised by the individual states are responsible for identifying public policy needs, in a process called the State Agreement Approach that is largely independent of the SO's planning process.

4.27 'Public policy needs' can be loosely defined as those electricity transmission assets that are required by any local and/or federal action. This could include, for example, connection of generation that had been built to meet environmental targets. The need to consider (but not necessarily mandate) public policy requirements in the US was introduced by FERC Order 1000.[78]

4.28 To coordinate transmission requirements between ISO jurisdictions, FERC Order 1000 has mandated that neighbouring ISOs must, *inter alia*:

- exchange transmission planning data and information at least annually;
- share information on interregional investment needs with each other; and
- identify and jointly evaluate potential solutions to those needs.

4.29 This has led to the formation of cross-regional committees that coordinate interconnector investment (referred to as "interregional" assets in the US) between neighbouring regions. Two examples of this are described below:

[78] FERC considered that this *"supports rates, terms, and conditions of transmission service…that are just and reasonable and not unduly discriminatory or preferential."* FERC Order 1000, ¶166.

- The **Northeastern ISO-RTO Planning Coordination Protocol** is integrated into the planning processes of the member regions (PJM, NYISO and ISO-NE). Members annually review the regional needs and solutions identified in individual regions' planning processes. They then identify needs and propose solutions that can be met or replaced by an interregional asset. Where this is the case, members will propose interregional assets in accordance with the respective regions' planning processes. Upon identifying proposed solutions in the individual regions' transmission plans that would be more efficient or cost effective if replaced by an interregional asset, *"the corresponding existing regional transmission projects shall be displaced".*[79]
- The **MISO-SPP JPC**[80] is not integrated with the individual planning processes of MISO and SPP, unlike the Northeastern ISO-RTO process set out above. Instead it runs an annual Transmission Issues review which separately evaluates if any transmission needs have arisen for reliability, economic and/or public policy reasons that could be addressed with an interregional asset.

4.30 Different approaches have been adopted to coordinate large-scale renewables generation and long-distance transmission investments. Examples include:

- In 2005, the Public Utilities Commission of Texas ("PUCT"), the regulator, and the Electric Reliability Council of Texas ("ERCOT"), the SO, began to develop Competitive Renewable Energy Zones ("CREZ") and a transmission plan to deliver the power generated from CREZ sites to customers. This was an example of proactive transmission investment whereby renewable zones were sited and transmission lines committed before any physical generation plants were built. While this has spurred significant transmission investment, other commentators have noted that customer bills have risen considerably as well,[81] with an uncertain balance of benefits between consumers and producers.

---

79 Northeastern ISO/RTO Planning Coordination Protocol, 10 July 2013.

80 Joint Planning Committee ("JPC") pertaining to the Midcontinent Independent System Operator ("MISO") and Southwest Power Pool ("SPP").

81 E&E News (2015) Rising costs in Texas challenge retail market, accessed at: https://www.eenews.net/stories/1060022490.

- The MISO Regional Generation Outlet Study ("RGOS") developed plans for renewable energy zones by coordinating renewables targets between its member states. The RGOS intended to design a transmission plan that would enable individual MISO member states to meet their Renewable Portfolio Standards ("RPS") at the lowest wholesale cost to the region.[82] Some combination of local generation (meeting RPS with resources located within the same state as the load) and regional generation (meeting RPS with resources located in renewable energy zones with high resource availability, which required additional transmission investment) was found to be the most cost effective.[83]

Europe

4.31 ENTSO-E's Regional Investment Plans identify system needs at a regional level, taking into account the Pan-European view as well as the views of individual Member States within the regions. The plans are separated into six geographical regions (North Sea, Baltic Sea, Continent Central East, Continental South East, Continental Central South and Continental South West), shown in Figure A1- 10 in Appendix 1. For example, the North Sea Regional Group includes GB, Ireland, Benelux, France, Germany, Norway and Denmark.[84]

4.32 The Regional Investment Plans identify potential projects based on the needs identified in the Common Planning Study (produced jointly by the European regions). The TYNDP includes the projects in the Regional Investment Plans,[85] but explores the options at greater depth (for example, a CBA is performed) and takes a pan-European, rather than regional, perspective.[86] However, full decision-making responsibility for specific investments lies with the respective TSOs upon approval of the national regulators.

---

[82] The challenge was to balance lower transmission investment to deliver wind from low availability areas (typically closer to load centres), against higher transmission investment to deliver wind from higher availability areas (typically further from load centres). Source: MISO (2012) Multi Value Project Portfolio.

[83] MISO (2010) Regional Generation Outlet Study.

[84] Some countries belong to more than one region: for example, Norway belongs both to the North Sea region and the Baltic Sea region.

[85] Other options can also be submitted by TSOs and third parties for consideration in the TYNDP.

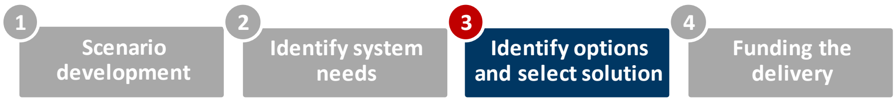
[86] ENTSO-E, Regional Investment Plan 2015 North Sea region, Final version after public consultation, 30 October 2015.

Germany

4.33 In Germany, the TSOs are responsible for identifying system needs based on the scenarios approved by BNetzA. The GDP aims to use a combination of AC and DC transmission lines to optimise how needs are met in each of the scenarios.

4.34 For offshore transmission assets in Germany, the TSO undertakes a proactive offshore Grid Development Plan and identifies offshore sites where it intends to build a transmission line. This is overseen by the regulator who sets the cost recovery mechanism. By proactively determining where the transmission asset will be built, offshore wind farms are able to build around the proposed transmission line in 'clusters'.

Stage 3: Identify options and select solution



4.35 Jurisdictions in GB, US, Europe (at the EU level) and Germany apply different tests for different asset types.

4.36 The SO and/or regulator tend to be significantly involved, seemingly to facilitate greater information coordination, to provide an independent view on transmission planning, and for additional/complementary verification of the costs and benefits. Most CBAs are typically run by the SO (with oversight by the regulator, particularly if the TO and SO are a single entity), but some CBAs are run directly by the regulator, for example interconnector assessment in GB.

Great Britain

4.37 In GB, investment tests vary across asset types such as onshore assets, interconnectors, and offshore transmission assets.

4.38 For onshore transmission investments assessed under the SWW, as described earlier, the TOs identify the investment need. For this need, they propose solutions and run a CBA, based on the costs and benefits over a 40-year lifetime of the assets and using a discount rate set at the regulated level of the WACC. The recommended solution identified by the CBA process is then assessed and approved by the regulator.

4.39 In parallel, for onshore transmission investments assessed under the NOA, the SO collects potential technical solutions proposed by the TOs, and may also add its own solutions. The SO then runs a CBA using the same 40-year lifetime, but the methodology uses a single year 'least-worst regret' approach. The discount rate is based on the published Social Time Preferential Rate ("STPR") which is 3.5% in real terms. However, the solutions recommended by the NOA are non-binding and the ultimate responsibility for investment decisions stays with the TOs.

4.40 For interconnectors in GB, the regulator sets regulated cap and floor levels such that any revenues above the cap are then returned to consumers; whilst consumers 'top up' any revenue shortfalls if in a particular year the congestion revenues are low. The cap and the floor levels are linked to the cost of debt and a notional cost of equity. Ofgem conducts the CBA (over 25 years using a social discount rate) by assessing the likely GB net consumer welfare from the interconnector investment. Ofgem does not consider consumers in other countries or the generators in both countries. Ofgem takes into account, qualitatively, option value and other non-monetisable benefits of interconnectors.

4.41 For OFTOs, Ofgem designs a regulatory regime for competitive tendering where bidders select a 20-year revenue stream that covers the cost of owning and operating the asset, based on bidders' own discount rate (which is not made public).

United States

4.42 In the US, different investment tests are designed for economic, reliability or public policy investment needs. The ISOs, as fully independent entities, are generally strongly involved in the selection of the preferred solution, while the federal regulator, FERC, is relatively weakly involved. Importantly, the ISOs typically make an explicit effort to involve third parties in identifying potential transmission need solutions. ISOs can also identify and propose their own solutions. The decision on the preferred solution can be made by ISO stakeholder vote (e.g. in PJM), but this can also be made by state appointed regulators and committees (this is the case for example in ERCOT and CA).

4.43 NYISO runs three separate investment tests; one for each type of need: reliability, economic and public policy. The same discount rate is used to assess all assets – an average of each of the weighted average costs of capital of all the incumbent TOs in the NYISO region.

- For reliability needs, NYISO evaluates the technical viability and the cost-efficiency of potential solutions over a 10-year timeframe, and gives preference to market-based solutions over regulated solutions.

- For economic needs (e.g. to relieve congestion), NYISO first assesses which type of solution (generation, transmission or demand-response) is most likely to produce the greatest net benefit. NYISO then requests and evaluates specific transmission network solutions over a 10-year horizon. A voting approach is used whereby beneficiaries of the project (identified based on the relative load savings) vote on the proposed transmission project. Overall, NYISO retains a relatively passive advisory role by running models and providing results, and allowing potential beneficiaries to vote on assets.
- For public policy needs, identified by the New York Public Service Commission ("NYPSC"), NYISO requests and evaluates potential generation, transmission and demand-response solutions, which is subsequently reviewed by NYISO stakeholders and the NYISO Board may select a solution.

4.44 PJM runs two separate investment tests, for reliability and economic needs. The tests are interrelated in that a reliability asset can be considered an economic asset if it meets certain criteria. The same discount rate is used to assess all assets – a weighted average of the costs of capital of all the incumbent TOs in the PJM region.

- For reliability assets, PJM first evaluates if the proposed solution meets the identified need, and then evaluates the cost (the present value of the revenue requirement over 15 years).
- For economic assets, PJM assesses the costs and benefits of the projects. An economic asset is constructed if its benefit-cost ratio is above 1.25. In comparison to NYISO, PJM has a more active role and can recommend specific network upgrades.

4.45 Public policy assets in PJM are assessed via a State Agreement Approach, which is a separate process from PJM's cost benefit assessment. This contrasts with the NYISO approach, in which a state body proposes a public policy need, but NYISO runs the investment test and ultimately decides on the preferred solution.

4.46 FERC Order 1000 requires neighbouring ISOs to co-operate in planning interconnector (known in the US as "interregional") investments. As such there are various agreements in place between neighbouring ISOs that address cross-regional needs.

- The Northeastern ISO-RTO Planning Coordination Protocol serves to identify needs that could be met by interregional assets, or if the proposed solutions individual regions' transmission plans would be more efficient or cost effective if replaced by an interregional asset. If such needs are identified, proposals for specific solutions are then subject to the relevant evaluations in the respective ISO regions.
- The MISO-SPP JPC runs an annual Transmission Issues review, which evaluates if any transmission needs have arisen for reliability, economic and/or public policy reasons that could be addressed with an interregional asset. Unlike the Northeastern JIPC process, the Transmission Issues review is not integrated with the individual planning processes of MISO and SPP.

Europe

4.47 In Europe, investment tests are applied on a regional basis via ENTSO-E's TYNDP, supported by Common Planning Study and Regional Investment Plans:

- The Common Planning Study is produced jointly by European regions and considers the system needs based on ENTSO-E 'Visions'. It is a means for the ENTSO-E member TSOs to coordinate the identification of needs for example by using common methodologies. The output of the Planning Study is a series of potential infrastructure projects that may be included for consideration in the TYNDP.
- Each of the six European regions (see Figure A1- 9) builds on the needs identified in the Common Planning Study by identifying needs at a regional level. Again, the outputs of this Regional Investment Plan can be included for consideration in the TYNDP.

4.48 Every two years, the ENTSO-E opens a one-month application window, during which time TSOs or third parties may submit projects for consideration (i.e. to be included in the TYNDP), including based on the Common Planning Study and Regional Investment Plans as set out above. The identification of a 'need' is therefore carried out by the individual project 'promoters' rather than by centralised European authorities.

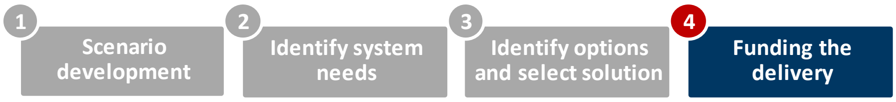
Germany

4.49 The identification of a transmission system need is different from the wider European processes within a country: in Germany, this is carried out via the TSO and regulator's plans, which may be informed by the TYNDP. The four German TSOs identify system needs based on the four scenarios as part of the GDP. This details the optimisation, expansion, and reinforcement measures required to address the needs of the electricity grid.

4.50 Following the decision of TSOs in GDP 2012, the GDP focuses on developing an optimal combination of AC and DC transmission lines in each of its scenarios. Based on long run scenarios, the recommended transmission investments typically include a combination of:

- Reinforcing existing AC transmission networks;
- Building new AC transmission networks; and
- Building long-distance 'ultra-high voltage' DC transmission lines (often serving as North-South 'corridors').

Stage 4: Funding the delivery of the asset



4.51 The funding of the delivery of the transmission solution varies across jurisdictions in terms of the approach cost recovery, and in terms of the distributional impact of the investment reflected in the cost allocation mechanisms. Jurisdictions allow for varying degrees of third-party involvement at this stage.

Great Britain

4.52 In GB, Ofgem is responsible for designing and implementing the regulatory regime which varies for different asset classes.

- Onshore transmission networks are fully regulated. The associated transmission investment costs are socialised across the users of the network, and are split between consumers and generators, with consumers paying a higher proportion.

- OFTOs follow an innovative approach to regulation whereby the regulatory regime for OFTOs allows for third-party developers through a competitive bidding process.[87]
- Interconnectors can be developed either as regulated assets under the Cap and Floor regime, or as merchant assets (subject to a regulatory approval). Merchant interconnectors bear all the costs of the project, but may be required by the regulator to share some of the upside benefit (e.g. return above a certain rate of return threshold) with customers. Cap and Floor regime allocates the majority of the costs and benefits to the developer of the interconnector, and the owner is able to earn merchant revenues within the cap and floor "band" set by Ofgem. However, when revenues rise above the cap or fall below the floor, the difference in revenues is socialised with consumers.

4.53 There is an increasing trend in GB to encourage greater third-party involvement to increase competition. Aside from interconnectors, Ofgem has also been considering competitive tender arrangements for new, large and separable onshore networks known as Competitively Appointed Transmission Owners ("CATOs"). This process has been put on hold due to an uncertain timing of the necessary legislation, but in the meantime Ofgem is proposing to use alternative approaches (Competition Proxy or Special Purpose Vehicle models), for example for the Hinkley Seabank project.[88]

4.54 Finally, GB regulation includes a specific approach to ensuring appropriate incentives are in place for transmission operators to maximise their availability (and benefits) to consumers over their operational lifetime. For example, Ofgem sets availability incentives for interconnectors and OFTOs. These incentives are linked financially either through the price control or the cap and floor licences.

---

87 However, to date, all OFTOs have been built by the wind farm developer before being transferred to a third party owner and operator.

88 Ofgem (2018) Update on competition in onshore electricity transmission (23 January 2018).

United States

4.55 Unlike its GB and EU equivalents, FERC does not impose specific cost allocation methodologies on transmission investments, although it must approve the cost allocation. Distributional impact of transmission investments may be reflected, with varying degrees of success, in the cost allocation methodology. For example, following FERC Order 1000 the US jurisdictions are required to adopt a beneficiary-pays principle for regulated assets, although the effectiveness of this principle remains uncertain (merchant assets will receive funding from equity, debt, etc.). In practice, the allocation of costs to different zones or parties varies across jurisdictions and asset types, and includes a combination of calculations based on ex-post flows,[89] simple cost socialisation,[90] changes in load energy payments, or other methodologies proposed by parties that FERC considers reasonable.[91]

4.56 However, there is no consensus as to the merits of the cost allocation methods applied:

- The Argentinian "Public Contest" model implemented in 1992 is widely regarded to be a successful example of a beneficiary-pays system. The NYISO investment test and cost allocation for economic assets is loosely based on this model. For a given proposed transmission investment, the SO identifies the parties that would benefit from the proposed expansion ("the beneficiaries") and each beneficiary's estimated monetary benefit from the new line. This estimated benefit determines both the weight of each beneficiary's vote and the proportion of total costs allocated to it.
- SPP's cost allocation methodology is another example of a 'beneficiary-pays' cost allocation approach. Costs of transmission investments are initially socialised among zones, but are then adjusted such that each zone's benefit is greater than the cost it has been allocated. This is facilitated by the fact that LSEs and generators are vertically integrated and are therefore able to jointly optimise the total benefits to generators and consumers (i.e. there are no consumer "winners" and producer "losers", or vice versa, as may otherwise be the case due to the price effects of transmission investment). This is therefore of limited relevance to the NEM.

---

89 In PJM this is known as the Distribution Factors ("DFAX") methodology.

90 Also known as the postage-stamp method, based on load-share ratios.

91 See ¶A1.113 and Table A1- 1 for full details.

- Cost allocation approaches in the US based on ex-post flows have faced criticism in the past. This is because such an approach effectively allocates costs based on the technical characteristics of the transmission line flows, rather than on its monetary benefits to different parties, which leads to incorrect results. In 2014, Con Edison argued that the costs that had been allocated to them for the Bergen-Linden line using the DFAX methodology did not take into account the benefits to PJM customers of fixing short-circuit violations[92] and argued that the DFAX methodology allocated an inappropriately high proportion of the costs to Con Edison because the transmission improvements would have been required even if they terminated their use of the PJM system.
- Some cost socialisation approaches in the US have been successful in delivering large volumes of transmission investment. In developing the CREZ transmission plan, PUCT and ERCOT agreed on a cost socialisation methodology before beginning the tender process. This was seen as one of the key reasons for the success of the project.[93] However, the primary purpose of policy makers was to deliver renewable energy in a cost-effective manner, in order to meet a particular policy goal. While some cost-benefit analysis of transmission paths (and specific renewable zones) was undertaken, this was not a holistic generation-*cum*-transmission optimisation process. As a result, this approach demonstrates the 'effectiveness' (but not necessarily 'efficiency') of the cost socialisation approach in ERCOT.

4.57 Implementing a 'beneficiary pays' approach in the US has been, in practice, challenging. Highly accurate beneficiary-pays approaches may not always be workable, particularly when the quantum and allocation of benefits must be estimated *ex ante*.[94] The main challenge is to develop an approach that approximates the allocation of costs to those who benefit from the investment, while also remaining simple, transparent and practicable.

---

92 Which, Con Edison argued, was the main purpose of the Bergen-Linden line in the first place.

93 ERCOT (August 2014) The Competitive Renewable Energy Zones Process – presentation by Warren Lasher, pp 10.

94 In the NEM, the interregional transmission charges are calculated ex-post on an annual basis.

4.58 Additionally, while transmission investments are assessed in the US over a period of time that is shorter than the typical useful life of a transmission asset, their costs are typically recovered over their full useful life.

4.59 There is a strong preference for third-party involvement in the transmission planning process in the US. For example, in choosing preferred solutions to meet reliability needs, NYISO will only consider regulated solutions if market-based (merchant) solutions are insufficient to meet the given need. Moreover, FERC Order 1000 removed the Right of First Refusal of Regional Transmission Organisations ("RTOs")[95] and ISOs for transmission planning, which related to the incumbent TO previously having the right to build and operate the transmission asset. The FERC Order 1000 prevents ISOs from intentionally excluding third parties from the transmission planning process and supports non-TO parties building and operating transmission projects.[96]

4.60 Finally, regulatory treatment (i.e. investment cost recovery) varies between individual states, so there is no consistent approach across all US jurisdictions.

Europe

4.61 As in GB, national regulatory authorities in Europe determine the price control and the cost recoverable by TSOs for transmission investments (typically from customers but also, depending on the Member State, from generators).

4.62 For the EU as a whole, the cross-border cost allocation ("CBCA") arrangements are in place for interconnector investments, in order to allocate cost of transmission investments efficiently between Member States. Projects developers (or promoters of the projects) can refer a specific project to the regulators involved with the investment to decide on how the costs should be allocated.

4.63 If the regulators are unable to reach an agreement, they will refer the project to the ACER to decide on the cost allocation. In general, ACER will allocate the costs to the entities who are responsible for the area that the project is sited in (this is the EU's approximation of the 'beneficiary-pays' approach). ACER may also, in some cases, allocate costs to a region where the asset is not physically located, but where the infrastructure makes the region a net beneficiary.

[95] These are the incumbent TOs in the US.

[96] FERC Order 1000, Summary.

4.64 While transmission planners can promote efficient cost allocation through a beneficiary-pays principle, there are examples of interconnectors where this principle emerges directly from the participants themselves (i.e. without planners' involvement). This occurs where beneficiaries of potential interconnectors find routes to provide financial support to underpin the construction of interconnectors that they believe will be in their economic interest. For example, NorthConnect (a planned link between Norway and Scotland) is likely to facilitate greater exports from Norway and is being developed by Nordic generators, while Piemonte Savoia (a France-Italy link) is promoted by a group of Italian energy-intensive industrial customers that would be likely to benefit from increased imports of low cost electricity from France into Northern Italy. Indeed, arguably, in GB, the regulator, Ofgem, sanctions customer support of interconnector projects if it considers that GB consumers will benefit on account of increased imports.

4.65 A separate mechanism known as the inter-TSO compensation ("ITC") is designed to mitigate the adverse impact on stakeholders following the re-distribution of benefits between consumers and producers within or between regions following the construction of a new interconnector. The ITC enables TSOs in neighbouring countries to partially compensate each other for hosting 'transit' flows, and specifically for:[97]

- the costs of losses incurred by national transmission systems as a result of hosting cross-border flows of electricity; and
- the costs of making infrastructure available to host cross-border flows of electricity.

Germany

4.66 In Germany, transmission costs are socialised to consumers via transmission charges. This applies to both onshore and offshore assets.

4.67 Third parties may submit projects for consideration in the ENTSO-E's TYNDP. In Germany, third parties could also propose changes to projects, or new projects, but the decision to incorporate the submission is at the discretion of BNetzA.

[97] ACER (2017) Report to the European Commission on the implementation of the ITC mechanism in 2016.

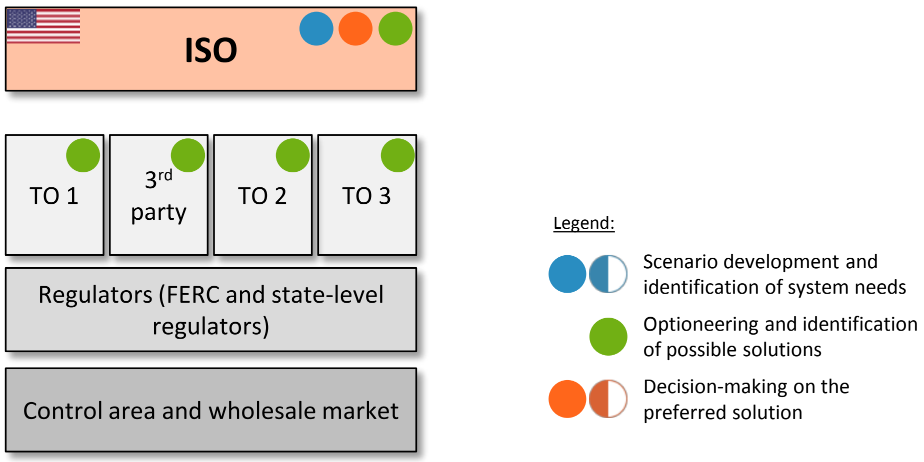
B. Transmission planning: comparison and assessment

4.68 All jurisdictions assessed in this report follow, in broad terms, the transmission planning lifecycle – i.e. they all undertake development of long term (and short term) planning scenarios, identify need(s) for transmission solution(s) to be implemented, apply a process to identify and select a particular solution, and have arrangements in place to fund the final solution that has been chosen.

4.69 However, the details of how this transmission planning process is undertaken differ between jurisdictions. Based on the analysis in the previous sub-section, we have identified two overarching types or 'models' of transmission planning.

4.70 First, we identified the "**US ISO model**" where a single ISO covers (in geographic terms) multiple TOs, and may in some cases span several States. The key roles of the SO, TOs and regulators in relation to other market participants are illustrated in Figure 4-2 below. This particular stylised version of the US ISO model has been developed in line with the PJM case study (rather than other US-based ISOs).

Figure 4-2: US ISO model: summary of key roles

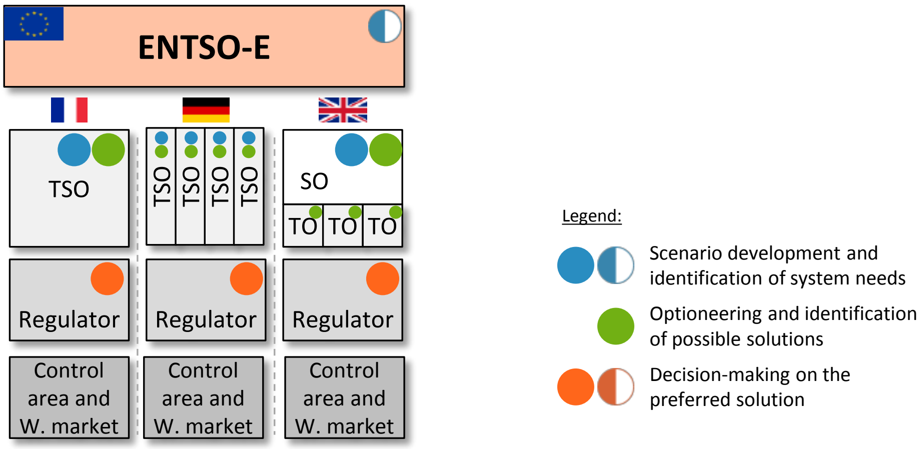


Source: FTI-CL Energy analysis.

4.71 As shown in Figure 4-2 above, in the US ISO model the ISO is responsible for the development of long-term scenarios and the identification of the system needs. Different parties can propose solutions to the identified system needs, including TOs, third party developers as well as ISOs themselves. In this model, the decision on the preferred transmission solution lies with the ISO.

4.72 Second, we identified the "**European model**", where multiple SOs and TOs interact within a Europe-wide framework. In this model, we consider that the transmission planning approaches used in Germany and GB are the constituent parts of the overall European model. In the European model, ENTSO-E as the pan-European entity representing national SOs covers (in geographic terms) multiple TSOs, SOs and TOs[98] across different countries. The key roles of the SO, TOs, regulators and other market participants are illustrated in Figure 4-3 below.

Figure 4-3: European model: summary of key roles



Source: FTI-CL Energy analysis.
Note: "W.market" stands for "wholesale market".

4.73 As shown in Figure 4-3, in the European model the national TSOs (or SOs) lead the development of long-term scenarios and the identification of system needs. However, ENTSO-E plays an advisory role in developing its own scenarios, and also by advising on cross-country transmission needs. Potential transmission solutions are typically identified by the TSOs or TOs, although SOs (e.g. in GB) can also propose solutions. Third parties are also able to propose new projects (notably interconnectors). In this model, the decision on the preferred transmission solution lies with the national regulatory authorities (without any formal role for the supra-national ENTSO-E).

98 Some European countries have a single TSO such as France; while others have multiple TSOs (e.g. Germany), and in other countries there is a separation between SO and TO functions (e.g. Great Britain).

4.74 We compared the two overarching models (the US ISO model and the European model) in terms of the roles played by different parties in transmission planning, and set out their key advantages and disadvantages below.

4.75 One of the key benefits of the US ISO model is that the decision-making regarding transmission solutions is consolidated at ISO level, and this is done with high level of transparency and independence of the SO. In addition, based on the analysis in the previous section, it seems that ISOs such as PJM are effective at delivering transmission investments that link multiple TO footprints (which is not necessarily the case in the European model). Finally, the US ISO model uses an approach whereby different asset needs (notably reliability and economic needs) are integrated into a "seamless" transmission plan that enables the different needs to be assessed in a holistic manner.

4.76 However, the US ISO model faces its own challenges. In particular, while FERC has significant legislative powers, transmission planning is often left to the individual ISOs whose mandate is to plan for their own respective jurisdictions. ISOs plan to meet their own reliability requirement in their respective jurisdictions and are unable to rely on the availability of resources outside their geographical footprint. Hence, the development of interregional assets (i.e. between different ISO footprints) is relatively complex, and relatively uncommon, unless there is a strong economic case to be made. One of the aims of FERC Order 1000 (issued in July 2011[99]) has been to provide supporting rules, but these have yet to drive significant volumes of new interregional investments. Finally, it is notable that the regulatory treatment (i.e. investment cost recovery) varies state by state and there is no single consistent approach used by all ISOs.

4.77 In the European model, ENTSO-E plays an advisory role, eliciting information from national TSOs, and aims to coordinate cross-border investments between independent jurisdictions (which are, in this model, sovereign states). Similarly to the US ISO model, there are country-level regulators (corresponding to the state-level regulators in the US), but there is no FERC equivalent in Europe.

99 United States of America Federal Energy Regulatory Commission 18 CFR Part 35, Docket No. RM10-23-000; Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities (Issued July 21, 2011).

4.78 In this model each country functions as an individual control area (in terms of the SO balancing, albeit with some coordination between TSOs at the day-ahead stage) and a wholesale market. National authorities (often TSOs and/or regulators) retain the ultimate responsibilities for investment approvals, which complicates, and, in turn, probably deters, investment in cross-country interconnections.

4.79 While ENTSO-E is relatively active, it inevitably lacks the political power to enforce a transmission plan – its plans are merely advisory. Furthermore, we see little evidence that EU countries have been willing to cede too much control to a pan-national planning organisation (as observed, for example, in the development of individual capacity mechanisms by each EU country).

4.80 In addition, ENTSO-E, in its advisory role for cross-Europe coordination, does not currently have any system operation role(s). This is different from the US ISO model, where a single ISO covers an area that corresponds to a single control area and wholesale market. In other words, the European model represents a fragmented market, where the function of the system operator (and wholesale market operator) is disjointed from the transmission planning role. Similar to the US ISO model, the regulatory treatment (i.e. investment cost recovery) in the European model varies by country and there is no single ‘best’ approach applied by different European countries.

5. Transmission planning in the NEM

5.1 This section provides an overview of transmission planning in the NEM.

5.2 In turn, we set out:

- the history and organisation of the market, including roles of different entities in transmission planning, as well as the emerging challenges facing the electricity system (Section A); and
- a summary of the NEM's transmission planning framework in the context of the transmission planning lifecycle (Section B).

A. Overview of the NEM

5.3 The NEM is the wholesale electricity market that operates across the southern and eastern states of Australia. It operates as a regional market with the potential for different wholesale prices in each region. Each price region maps to each of the five states: Queensland, South Australia, Tasmania, Victoria and New South Wales (including the Australian Capital Territory ("ACT")). Figure 5-1 below shows the overall geographic footprint of the NEM.

Figure 5-1: Map of NEM

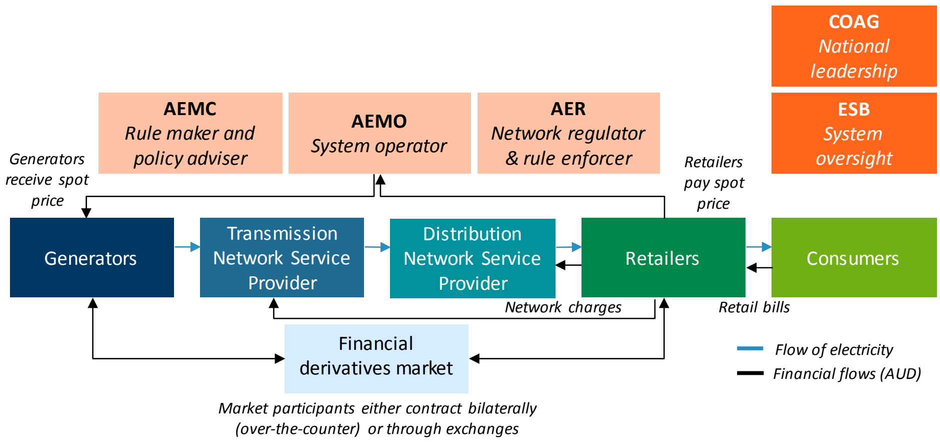
5.4 In this subsection, we set out at a high-level, the history and design of the NEM, and the emerging trends and challenges in the NEM.

a) The history and design of the NEM

5.5 The NEM was created in 1998, as part of the process of liberalisation of the sector, to create a single electricity market connecting five states and the ACT.

5.6 As with many other liberalised electricity sectors across the globe, the NEM is split into four main elements of the value chain. There are also a range of regulatory and government bodies that oversee the operation of the sector. Figure 5-2, below, summarises the organisational structure of the NEM.

Figure 5-2: Overview of the NEM organisational structure



Source: FTI-CL Energy analysis.

5.7 As illustrated in Figure 5-2 above, the generation and retail sectors are competitive markets while the transmission and distribution networks are local monopolies.[100] The networks are regulated by a national regulator – in Australia this is the Australian Energy Regulator ("AER").

5.8 The NEM is governed by the National Electricity Rules, with changes overseen by the AEMC and typically enforced by the AER.

5.9 AEMO is both the system operator and the market operator – and has a key role in transmission planning. It operates the NEM to deliver a range of market, operational and planning functions. This includes information provision, system balancing and market facilitation.

100 This assumes 'traditional' power flows of generators connected to the transmission network. Increasingly, more generation are being connected at a local level.

5.10 The NEM is an energy-only market with a mandatory spot market (also known as a gross pool market) where generators must sell all of their electricity output. AEMO determines the demand in the gross pool market for each five-minute period based on the expected demand in each region. A different spot price is set in each region based on the RRN.

5.11 There is also an ancillary services market run by AEMO that provides the SO with the capabilities to ensure demand and supply is balanced on a second-by-second basis. AEMO utilises a range of ancillary services products which are procured through a combination of bilateral contracts and market-based mechanisms.

5.12 The NEM also has a financial derivatives market which allows market participants, including retailers and third-parties, to hedge against the volatility of the spot price.

b) Emerging trends and challenges in the NEM

5.13 In line with the experience of global energy markets, the NEM is transforming rapidly through a combination of technology advancements, changes to consumer preferences, and Government policy.

5.14 The main areas of transformation include:

- Flat or decreasing peak and total demand for electricity from the transmission grid owing in part to the proliferation of rooftop solar[101] and improved energy efficiency.[102,103]

---

101 AEMO (March 2018) AEMO observations: Operational and market challenges to reliability and security in the NEM, pp 10.

102 Commonwealth of Australia, Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, June 2017, pp 30.

103 Based on the data from the AER website (accessed at https://www.aer.gov.au/wholesale-markets/wholesale-statistics), between financial year 2008-09 and financial year 2016-17, total NEM electricity demand decreased from 211 TWh to 197 TWh, or a decline of 6.7%. Additionally, between summer 2008-09 to summer 2016-17, peak demand decreased from 35.8 GW to 34.8 GW, or a decline of 2.8%.

- Increased investment in large-scale renewables generation capacity with intermittent and volatile production, which increases unpredictability of the supply/demand balance, reduces system inertia and may require significant investment in transmission capacity to connect resource-rich renewables areas to demand centres;[104]
- Falling coal-fired generation as those assets approach the end of their useful lives, reducing the amount of dispatchable capacity on the system;[105] and
- Continued uncertainty over long-term environmental policy which, in turn, impacts the investment dynamics of both renewable and non-renewable energy sources.[106,107]

5.15 These trends, and the underlying uncertainty on how fast these trends will develop over time, have presented significant challenges in the NEM, particularly in terms of the potential risk of decreasing energy reliability and increasing the cost to consumers.

5.16 To navigate these challenges, it is widely anticipated that transmission planning will play a key role. Some of the key questions that a transmission plan would need to consider includes:

- How will demand change over time, especially in view of potential electrification of transport (i.e. electric vehicles)?
- How long will existing thermal generation be maintained, and which generation technology (or technologies) will be most cost-effective to replace them? How will the need for flexibility and reliability be met?

---

104 "*Older baseload units find it increasingly difficult to compete in the current environment…their business model will be further challenged by increasing variability in the system and falling costs of competitive sources of energy*." AEMO (March 2018) AEMO observations: Operational and market challenges to reliability and security in the NEM, pp 16.

105 AEMO (March 2018) AEMO observations: Operational and market challenges to reliability and security in the NEM, Figure 10.

106 Similar issues are now commonplace across the globe, as increasing renewables penetration affects the structure and dynamics of electricity markets.

107 "Central to Australia's strategic energy plan must be a credible, stable emissions reduction policy…Stakeholders have identified the absence of such a policy as the critical challenge". Commonwealth of Australia, Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, June 2017, pp 31.

- How can the existing transmission network be “configured” in view of changing demand and supply fundamentals?
- How should REZ be valued and identified to facilitate required investments at least cost to consumers?
- How will distributed energy resources be considered in generation and transmission planning?
- What are the technical requirements of the system, given the ongoing changes in the NEM, how can energy security be improved?

B. Transmission planning in the NEM

5.17 This subsection summarises transmission planning in the NEM in the context of the transmission planning lifecycle. In turn, we set out:

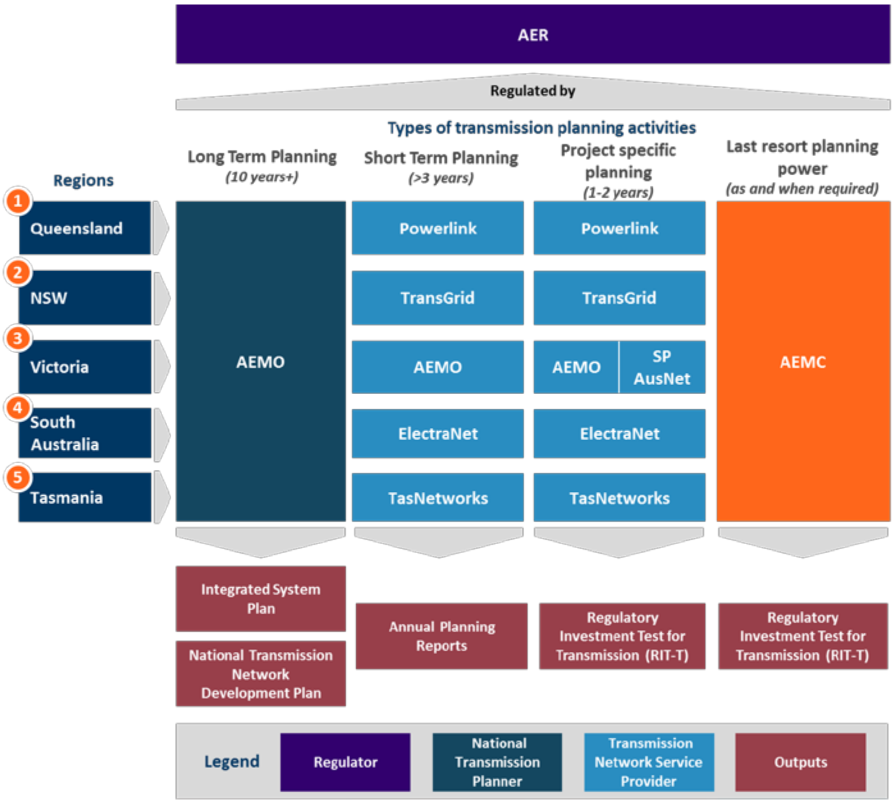
- the main regulatory objectives and key roles played by different parties in the NEM;
- the current transmission planning framework in the NEM;
- the practical constraints that complicate transmission planning in the NEM; and
- a review of the recent assessments and changes to transmission planning that have been proposed by various market participants in the past.

a) Regulatory objectives, roles and responsibilities of transmission planning

5.18 Transmission planning in the NEM involves a coordinated effort from various parties. The AER, AEMO, TNSPs and the AEMC have specific roles in transmission network planning for the NEM. In addition, some transmission investments require approvals from the Federal Government and/or State Governments.

5.19 These roles are illustrated in Figure 5-3 below.

Figure 5-3: Current arrangements for transmission planning in the NEM



Source: FTI-CL Energy analysis.
Note: While COAG, AEMC and state governments are not typically involved in the detailed planning for each project, they provide important input in the development of the overall process.

5.20 AER regulates transmission networks to ensure that "*consumers pay no more than necessary for the safe and reliable delivery of energy services*".[108] This role is determined by the National Energy Objectives "*to promote efficient investment in, and efficient operation and use of, energy services for the long-term interests of energy consumers with respect to price, quality, safety, reliability and security of supply*".[109]

108 AER (2016) Statement of Intent 2016-17, pp 6.

109 AER (2016) Statement of Intent 2016-17, pp 2.

5.21 AEMO undertakes long-term transmission planning across all states, while the planning of specific transmission investments is undertaken by the individual TNSPs via the RIT-T. The exception to this is in Victoria, where AEMO shares the project specific planning role with SP AusNet.

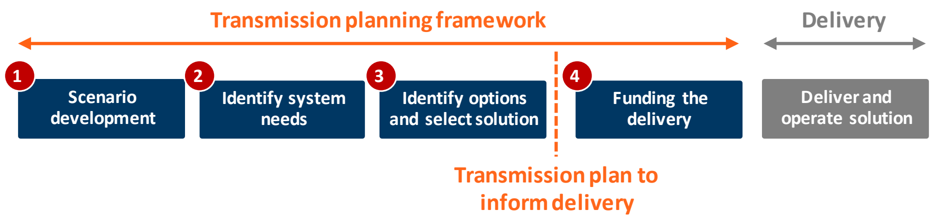
5.22 The TNSPs are the incumbent owners and operators of the transmission network in the NEM. The TNSPs also hold the transmission planning role in their jurisdiction, including by having the responsibility for undertaking the RIT-T. They therefore have a dual role as planners and owners of the transmission networks.

5.23 The AEMC is the expert energy policy advisor to the Australian governments. It is responsible for making and revising the market operation rules and for the market design of the NEM. For the purposes of transmission planning, the AEMC acts as the planner of last resort as and when required.[110]

b) Current transmission planning arrangements in the NEM

5.24 Based on the various transmission planning roles illustrated in Figure 5-4 below, this subsection sets out the transmission planning arrangements in the NEM.

Figure 5-4: Transmission planning lifecycle



Source: FTI-CL Energy analysis.

5.25 We discuss each stage in turn below.

[110] To date, AEMC has not exercised its last resort planning power. AEMC (2017), 'Last resort planning power – 2017 review'.

Stage 1: Scenario development

5.26 A key source of information for the purposes of scenario development in the NEM has been, until the introduction of the ISP, the annual NTNDP produced by AEMO. This gave an *"independent, strategic view of the efficient development of the NEM transmission grid over a 20-year planning horizon"* and contained forecasts of generator capacity, load and other metrics necessary for the planning of transmission investment.[111] The NTNDP also took into account the Annual Planning Reports ("ARPs") of the TNSPs.

5.27 The long-term scenarios continue to be developed by AEMO. Specifically, the:

- Integrated System Plan ("ISP") includes a range of scenarios and sensitivities over a 20-year period to "*assess how efficient generation and transmission development may be impacted by a range of uncertainties*";[112,113] and
- Electricity Statement of Opportunities ("ESOO") which "*provides technical and market data that informs the decision-making processes of market participants, new investors, and jurisdictional bodies as they assess opportunities in the National Electricity Market (NEM) over a 10-year outlook period*".[114]

5.28 Individual transmission system network providers ("TNSPs")[115] publish annual planning reports and undertake the investment tests for project-specific planning ("RIT-T"). These shorter-term planning documents typically rely on the longer-term projections published by AEMO. However, TNSPs are not obliged to adopt AEMO's scenarios in their planning processes.

---

111 AEMO (2015) National Transmission Network Development Plan.

112 AEMO (December 2017) Integrated System Plan Consultation.

113 Before the ISP was developed, AEMO published an annual National Transmission Network Development Plan ("NTNDP") "*provides an independent, strategic view of the efficient development of the National Electricity Market (NEM) transmission grid over a 20-year planning horizon*".

114 AEMO website, NEM Electricity Statement of Opportunities, viewable at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

115 This report refers to transmission operators in the NEM as TNSPs. These are referred to interchangeably with TOs.

5.29 This first ISP, released in July 2018, considers the development of renewable energy zones in the NEM and corresponding transmission development options. This subsumes some of the previous activities and objectives of the NTNDP.

5.30 The information in both these documents will be used to form "reasonable scenarios" across which those proposing transmission investments must estimate expected benefits for the RIT-T. TNSPs performing the RIT-T are free to set their own scenarios, but in practice most use scenarios set out by the NTNDP.[116]

Stage 2: Identify system needs

5.31 In the NEM, system needs are identified by TNSPs. A given need may represent a reliability corrective action,[117] or an expected increase in the net economic benefit to consumers and producers in the NEM. Transmission needs may be suggested by TNSPs in their Annual Planning Reports ("APRs"), which feed into AEMO's scenario development.

5.32 AEMO also identifies long-term system needs via the NTNDP/ISP. In particular, AEMO has a role where the need relates to system security under the Network Support and Control Ancillary Services ("NSCAS") framework and recent system strength and inertia rules changes.[118]

5.33 It is intended that the publication of the ISP will provide a more reliable and robust integrated view of the entire system. The ISP 'identifies a need' by modelling the combination of generation and transmission investments required in each scenario that "*delivers reliable and secure electricity supply at the least cost to consumers".*[119] This model utilises a series of input assumptions such as the resource mix, weather patterns, and system constraints, as well as a range of investment options in generation, transmission and other technologies through an iterative approach.[120]

---

116 Productivity Commission (April 2013) Electricity Network Regulatory Framework Review, Volume 2, pp 633, FN6.

117 A "reliability corrective action" is an action that assists the TNSP in meeting any of the service standards linked to the technical requirements of Schedule 5.1 of the National Electricity Rules or other applicable regulatory rules.

118 AEMO (March 2018) Power system requirements.

119 AEMO (2018) Integrated System Plan, p. 24.

120 To an extent, the ISP reverts the transmission planning lifecycle – the modelling approach identifies investment options, and then determines the investment need through an iterative process.

5.34 Notably, system needs are not identified by state governments, AEMC, or the AER. This contrasts with the approach in NYISO and PJM in the US, where needs are identified by the respective states' SOs and/or state governments.

Stage 3: Identify options and select solution

5.35 This step is also performed by the TNSPs in the form of the RIT-T. The RIT-T is only applicable to projects with an expected cost exceeding AUD 6 million.[121] This threshold is reviewed by the AER once every three years.

5.36 Credible options to meet an identified need can be tabled by the TNSP or a third party. For each credible option, the TNSP calculates the present value of the costs of the option and compares this to the expected present value of benefits. The benefits can include the respective changes in: fuel consumption, load curtailment, involuntary load shedding, and a number of other factors.[122] The calculated benefits cannot include: transfers of surplus between consumers and producers or any indirect benefits (such as positive externalities).

5.37 The present value of the option's benefits must be recalculated for each reasonable scenario and weighted by an appropriate probability (determined by the TNSP) to give the expected present value of benefits.

5.38 The discount rate applied to the estimated costs and benefits is a commercial discount rate, which the TNSPs can vary between the credible options being assessed.[123] This is currently under review.[124] The credible option with the greatest net benefit is selected as the preferred option.

5.39 The ISP, to an extent, plays a role in the identification of options. This is used in its modelling to determine the 'optimal' generation, transmission and storage investment requirements in each scenario to meet reliability requirements at least cost to consumers. This then sets out the investment need, which could then be used to in this stage to determine a solution to invest in and deliver.

---

121 AER (2017), 'Regulatory investment test for transmission application guidelines'. AER must review this threshold every three years.

122 Including changes in: costs to parties other than the TNSP; timing of transmission investment; network losses; ancillary services costs; competition benefits; additional optionality values; and penalties avoided.

123 The exception to this is in the RIT-T in Victoria which relies on the social discount rate (the latest recommendation for this is 7%).

124 AER (February 2018) Review of the RIT-T application guidelines, Section 5.7. In practice, all TNSPs use a similar commercial discount rate in the RIT-Ts.

Stage 4: Funding the delivery

5.40 In general, the party that proposed the preferred option that is selected will be responsible for delivery of the asset. If the preferred option was one proposed by a third party, the TNSP will contract with it to provide the service and deliver the asset (this could include operation, construction, etc.). However, the TNSP retains ultimate responsibility for meeting the identified need.

5.41 On **cost recovery**, costs submitted as part of the RIT-T consultation are not directly linked to the regulatory asset base of the TNSPs. This is run separately through the price control process led by the AER.

5.42 On **cost allocation** in the NEM, transmission costs are allocated to transmission tariffs at:

- 50% to the locational component; and
- 50% to the non-locational component.[125]

5.43 The cost of transmission investments is predominantly recovered from end-user consumer tariffs. Generators pay for the TNSP's costs to connect them to the nearest appropriate point on transmission network, but do not need to pay for the portion of transmission costs that they might 'trigger' across the network, including network reinforcements. Different jurisdictions have varying levels of how 'deep' or 'shallow' transmission charges are. The 'deeper' the transmission charging regime, the more cost-reflective the charges are for each generator based on the use of the transmission network. Conversely, the 'shallower' the regime, the less cost-reflective the charges are, and the more 'socialised' transmission charges are across generators or end-users.

[125] AEMO (May 2015) Approved Amended Pricing Methodology for Prescribed Shared Transmission Services for 1 July 2014 to 30 June 2019, ¶3.3.2.

5.44 There is no requirement for TNSPs to adhere to the cost proposals that underpinned the investment decision made during the RIT-T process. Currently, all Capex incurred in developing new transmission is included in the respective TNSP's RAB (if it does not significantly exceed the allowance set through the price control), regardless of whether a RIT-T took place for said Capex. This may create a concern for policy makers that TNSPs might be allowed to earn revenues on assets whose costs have overrun those identified in the RIT-T, or if TNSPs took unilateral action to build an asset without undertaking a RIT-T (even when one was required).[126] This creates the risk that had costs been correctly assessed in the investment test, the investment might not proceed.

c) Practical constraints complicating transmission planning in the NEM

5.45 There are several practical constraints that complicate transmission planning in the NEM. These include:

- the electricity wholesale market design within each NEM region;
- generators not paying transmission charges, and the lack of firm access;
- the historical preference for a single test for all asset types; and
- the development of REZs in the NEM.

The electricity wholesale market design within each NEM region

5.46 The NEM's electricity wholesale market design is different relative to other jurisdictions. There are two key differences, namely:

- the use of the RRN to set the price across the entire region; and
- the lack of firm access for generators (i.e. generators will not receive compensation payments if they are unable to dispatch due to a constraint).

5.47 In turn, the combined effect of these two market design approaches mean that the NEM is affected in the following three ways, which in turn would affect transmission planning:

- First, there is a lack of locational signals within each NEM region;
- Second, the NEM's congestion management approach could impact the wholesale price within each region; and

---

126 The COAG (February 2017) RIT-T Review (pp 30) notes that *"A project's costs can be rolled into a transmission network business' asset base even though business proceeded with the project without a RIT-T (and one was required) or where there is a substantial increase in the project costs identified in a RIT-T"*.

- Third, the potential distortions in generator bidding incentives may further diminish efficient price signals.

5.48 First, on locational signals, the NEM features a zonal pricing regime, where a different wholesale electricity price is set in each of the five regions. This contrasts with nodal pricing, where wholesale prices can vary at each node (a key feature of the US electricity market), and a single price zone, where the wholesale price is set based on the entire system (a key feature of the GB electricity market).

5.49 The use of zonal pricing, as opposed to nodal pricing, means that the observable impact on prices from transmission investments within each region is limited. Intra-regional transmission investments might therefore not be able to produce the measurable change in prices at either end of the asset. This creates further complexity on how these benefits can be quantified when evaluating the investment.

5.50 Second, on the NEM's congestion management approach, the impact of congestion on wholesale prices means that the economic impact of specific transmission investments can be observed and monetised despite the lack of locational pricing.[127] This is because a constraint that prevents a lower marginal cost generator to export electricity to the RRN might result in a higher clearing price than would have cleared absent of a constraint.[128]

5.51 The economic value of such investments is considered further in Box 5-1 below.

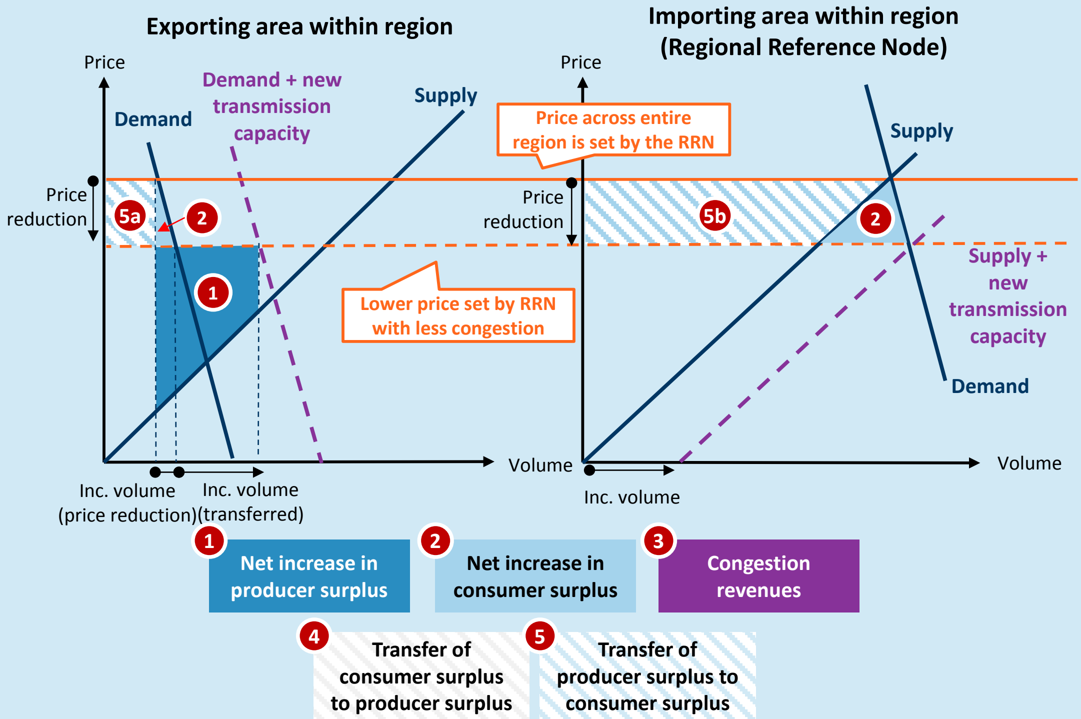
---

[127] There are two potential caveats. First, intra-regional constraints that are not at the RRN might not have an observable impact on prices. In these cases, it might be more difficult to identify and quantify the transmission need. Second, the lack of constrained-on or off payments might affect the bidding behaviour of generators, which in turn, may mask the investment impact of a transmission asset.

[128] Additionally, this generator would not receive constrained-off payments. This might result in inefficient short-term operating decisions on bidding and dispatch, but might also affect long-term investment decisions on generation investment.

Box 5-1: Economic value of intra-regional transmission investments in the NEM

In the NEM, the RRN sets the electricity wholesale price across the entire region based on the clearing price at the node. If there is congestion, and the import-constrained area is the RRN, a higher marginal cost generator that sets the clearing price would do so for the entire region, thereby increasing producer surplus export-constrained area. The impact of a new transmission asset to relieve congestion within a region is illustrated below.



The economic benefits from the transmission investment include an increase in consumer surplus (Area 2) and a transfer of producer to consumer surplus (Area 5b) in the RRN region. In the exporting area, there is an increase in producer surplus as congestion is relieved (Area 1), an increase in consumer surplus (Area 2), plus another transfer of producer to consumer surplus (Area 5a) due to the price reduction. There are no congestion revenues as both areas are in the same price zone.

A pure 'economic efficiency' approach would consider areas 1 + 2 (i.e. ignore the distributional impact). However, this fails to recognise that the producer surplus in the exporting area (before the new transmission investment), is pushed up by the market design itself, as the exporting region's price is set at the RRN clearing price. In these circumstances it may be reasonable to include Area 5a in the welfare assessment (in addition to areas 1 and 2), even though it is a transfer rather than a newly created surplus.

5.52 Third, the lack of firm access might create potential distortions in bidding incentives. Two low marginal cost generators competing at an export-constrained area within a region might have an incentive to bid as low as possible to avoid being constrained-off (which, as a consequence of the market design, results in no financial payments). This might result in a 'race to the bottom' towards the NEM bid floor of negative AUD 1,000, which we understand is known as 'disorderly bidding'. Additionally, if a constraint expected by these generators is later found out to not exist, this might cause the regional reference price to fall, potentially significantly.

5.53 Conversely, higher cost constrained-on generators at the RRN that have the ability to set the price across an entire zone, rather than receive a separate constrained-on payment might have the incentive to increase bid prices.

5.54 These disorderly bidding incentives might therefore further diminish wholesale price signals to an extent that prices do not reflect supply and demand dynamics in the market accurately. In turn, this might impact transmission planning as it would be less clear:

- where transmission investment might be needed to relieve a constraint;
- how much value the transmission investment might provide to the system;
- if and where generation investments will be made, which will inform transmission investments; and
- if and how much generators should pay for connecting to and using the transmission network, commensurate to the benefits they receive (i.e. deep vs shallow pricing on connection charges, see ¶5.43, and use of system charges, which generators do not pay).[129]

[129] Generators are only pay a 'shallow' connection charge as well as a component of the marginal loss factor which affects the outturn price it receives for generating electricity. AEMC (2018) Coordination of generation and transmission investment, pp.18.

The historical preference for a single test for all asset types

5.55 The RIT-T has historically been a single test for all asset types. This approach was decided on in 2009, combining the two 'limbs' of what was previously called the Regulatory Test. These two 'limbs' used different tests for investments driven by reliability needs and investments driven by market benefits. The current approach seeks to identify a 'preferred option' defined as the credible option that "*maximises the net economic benefits to all those who produce, consume and transport electricity in the market compared to all other credible options*".[130] We understand that this makes it difficult to justify transmission investments that have high strategic value that may not manifest as quantifiable economic benefits.

5.56 The RIT-T's prescriptive approach means some have noted that it might not have sufficient flexibility to evaluate the strategic or pro-active investments. This means that the test might not capture the full strategic value of an investment – such as multi-purpose investment or one that requires more significant coordination of transmission and generation.

The development of REZs in the NEM

5.57 The Finkel Review proposed the creation of REZ in the NEM. Many stakeholders, via ISP Consultation responses, acknowledged that REZs could bring forward new generation and transmission development and investment to the benefit of consumers.

5.58 Additionally, the Finkel Review found that there is a coordination issue between generators and TNSPs under the current regulatory framework.[131] This may result in an underinvestment in generation and transmission.

5.59 To address these coordination issues, the success of REZs is likely to require effective coordination not only between generators and transmission owners/investors, but also between the various states or zones over which transmission lines may cross, to form an *integrated* view of the optimal generation and transmission build.

---

130 AER, Regulatory Investment Test for Transmission, June 2010.

131 Commonwealth of Australia, Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, June 2017, pp.125.

d) *Recent assessments and proposed changes to the transmission planning framework in the NEM*

5.60 Given the increased importance of transmission planning, there have been several assessments of the transmission planning framework, with some focussing on the RIT-T in particular. We discuss five notable examples below:

- The Productivity Commission Inquiry Report on Electricity Network Regulatory Frameworks ("The Productivity Commission Report");
- The Council of Australian Government's ("COAG") review of the RIT-T;
- The Finkel Review;
- The AER February 2018 consultation; and
- ISP consultations.

5.61 The AEMC and AER are also currently reviewing the NEM's planning process:

- the AEMC is reviewing the NEM framework for the coordination or generation and transmission investment (including through REZs); and
- the AER is currently reviewing its RIT-T guidelines.

The Productivity Commission Report

5.62 In 2013, the Productivity Commission was instructed to assess the NEM's current regulatory framework. In particular, it was to make recommendations on benchmarking methodologies and whether the current regulatory regime was delivering economically efficient outcomes with respect to interconnectors. The Productivity Commission Report recommended that the RIT-T should:

- continue to be performed by the TNSPs, but should be accompanied by independent analysis from AEMO;
- be used by the AER for revenue determinations for those projects;
- apply to all large transmission projects above a threshold value, irrespective of whether they are augmentation, replacement or new build;
- be triggered when a project exceeds a threshold value that is indexed over time to reflect its real value;
- assess a project's effect on reliability as a component of net benefits, and not as a separate criterion;
- include a publicly available probabilistic reliability assessment; and

- continue modelling the costs and benefits within the power market only, and not include any externalities.

The COAG Report

5.63 In 2017, the COAG Energy Council published a report assessing if the RIT-T remained fit for purpose in the context of the changing Australian electricity market ("COAG Report"). It made the following recommendations:

- The AER should review the RIT-T guidelines, and consider how the quantification of net benefits could better reflect optionality (including in relation to system security, and climate policies and objectives);
- Information on transmission networks should be more transparent and accessible, notably in respect of third parties who may put forward non-network solutions; and
- The merits of increased AER oversight of the RIT-T process should be explored.[132]

The Finkel Review

5.64 Transmission planning in the NEM as a whole has recently been assessed by the Finkel Review,[133] which was commissioned to provide an overall assessment of its current security and reliability, and to provide advice to governments on a blueprint for coordinated national reform. Transmission planning was not the sole focus on the Finkel Review, but was a key feature.

5.65 The Finkel Review highlighted three areas with regards to transmission planning where changes are required to meet national energy objectives on increased security, future reliability, protecting consumers and lower emissions:

- an orderly transition towards achieving an agreed emissions reduction trajectory;
- improved system planning; and
- stronger governance.

---

132 COAG (2017) Review of Regulatory Investment Test for Transmission (also known as "the COAG Report").

133 Commonwealth of Australia, Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, June 2017 (also known as "the Finkel Review").

5.66 On improved system planning, the Finkel Review made the following recommendations:

- A long-term, integrated plan for the grid that establishes the optimal transmission network design to enable connection of renewable energy resources, including through interregional connections.
- Improved coordination of generation and transmission planning and investment.

5.67 The Finkel Review notes that *"enhanced system planning will ensure that security is preserved, and costs managed, in each region as the generation mix evolves. Network planning will ensure that new renewable energy resource regions can be economically accessed".*[134]

5.68 The Finkel Review notes that, at present, there is limited guidance on prospective zones for solar, wind, or pumped hydro storage in AEMO's current transmission planning. Moreover, TNSPs generally only discuss the location of renewable energy resources at a high level in their annual planning reports.

5.69 The Finkel Review recommended that AEMO, TNSPs, and other relevant stakeholders collaborate in determining the optimal transmission network design to enable the connection of renewable energy resources, including through interconnector investment. The result would be an integrated grid plan for the NEM transmission network. Any transmission network plan should be made publicly available to allow investors to make informed decisions about generation investment.

5.70 The Finkel Review notes that the integrated grid plan would ideally:

- Identify and map prospective REZs in the NEM, including (but not limited to) wind, solar, pumped hydro, and geothermal resources;
- Identify transmission network routes that efficiently connect REZs to the existing network, including routes for interconnectors that pass through these areas; and
- Include a high-level assessment of the relative economics of different zones, taking into account the quality of the resource, approximate cost of connection, network impacts, and other relevant factors.

[134] Commonwealth of Australia, Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, June 2017 (also known as "the Finkel Review").

The AER February 2018 consultation

5.71 In February 2018, in accordance with the recommendations of the COAG Report, the AER undertook a large-scale review of the RIT-T application guidelines. Stakeholders were invited to comment on the:[135]

- role of the RIT-T (and RIT-D) in promoting the long-term interests of consumers;
- process of the RIT-T (and RIT-D), including the timing, level of consumer engagement, and consideration of non-network options;
- application of the RIT-T (and RIT-D), including the identification of needs; and
- additional guidance stakeholders would find useful from the ISP.

5.72 Responses have been received, and the AER is due to publish its summary of these in September 2018.

5.73 On promoting the interests of consumers, the AER considers that the RIT-T achieves this by promoting competitive neutrality and efficient network decision making.

5.74 On the RIT-T's process, the AER expresses the view that greater attention needs to be given to promoting consumer engagement, noting that there is currently limited guidance in the RIT-T application guidelines on how to pursue this.

5.75 On the application of the RIT-T, the AER considers that greater clarity should be given on the identification of transmission needs to meet specific objectives (e.g. to connect generation), scenario analysis, and calculation of option values. The AER also wishes to explore the possibility of specifying a standard discount rate for RIT-T assessments.

ISP Consultations

5.76 In accordance with the Finkel Review's recommendations, AEMO has prepared an inaugural ISP for the NEM, which provides an integrated view of development needs over the next twenty years. This focuses on identifying:

- the determinants of a successful REZ and, once identified, how to develop it; and
- transmission development options.

---

135 AER (February 2018), Review of the RIT application guidelines.

5.77 In late 2017, AEMO ran a public consultation on the ISP.[136] In general, there was overwhelming support for the development of a long-term strategic approach to coordinated generation and network planning in the NEM, in the form of the ISP. Moreover, most respondents were of the view that the current process for approving regulated network investments needs to evolve to reflect changing market dynamics.

5.78 In their responses to the consultation, stakeholders recognised the need for strategic planning to manage the transformation of the power system, and supported the use of a least regret approach and staged decision making. Stakeholders were also supportive of a scenario approach to modelling that considers least regret developments that are robust under a range of scenarios, and that can be undertaken through staged implementation.

5.79 Also identified in responses to the consultation, was the need for robust planning processes that manage the integration of large amounts of utility scale variable renewable energy projects.

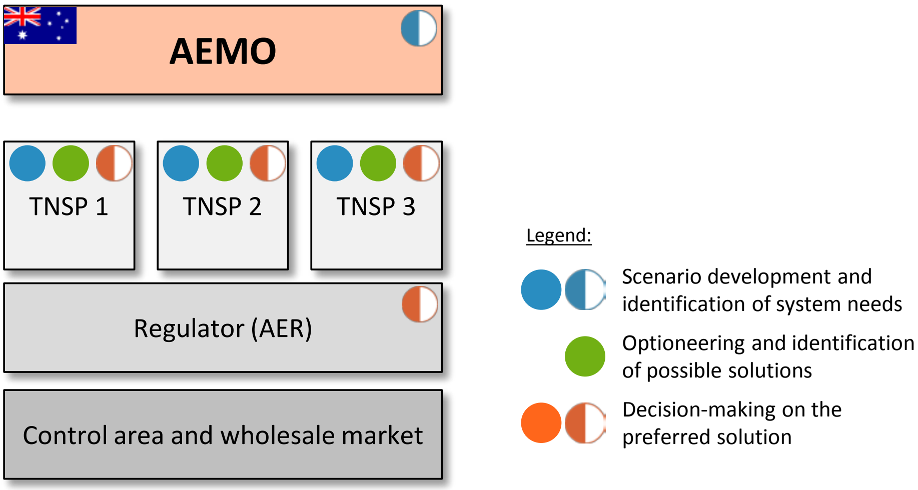
5.80 The idea of REZs elicited a wide range of views from consultation respondents. Many acknowledged that REZs could be an effective way to coordinate new generation and transmission development, thus delivering value to consumers through scale efficiencies.

C. Comparison of the NEM approach to international precedents

5.81 The NEM model is different from the transmission planning models in the US and/or Europe both in terms of the geographic coverage and the roles undertaken by different market participants. The main roles of AEMO, TNSPs and other parties are shown in Figure 5-5 below.

136 AEMO (2018) ISP Consultation – summary of submissions.

Figure 5-5: NEM model: summary of key roles



Source: FTI-CL Energy analysis.

5.82 The scenario development roles in the current NEM model are broadly similar to the European model (see Figure 4-3 in Section 4) in that the TNSPs in individual states have responsibility for developing scenarios and the identification of system needs (akin to the role played by European state-level SOs and TSOs). In addition, a central entity (AEMO) plays a key role in developing a common set of long-term scenarios through the ISP (and previously through different publications such as the NTNDP). This is akin to the role played by ENTSO-E in terms of seeking to coordinate multiple European countries.

5.83 The optioneering and identification of possible solutions are broadly similar across all three models (the NEM, the US ISO model and the European model) in that each model seeks to leverage the local knowledge (which often resides within the TO) by requiring the TOs to propose options which are then taken into account when assessing the potential transmission solution options. However, an important difference lies in the participation of third party solution providers: the US ISO model provides for a more formal (and mandatory) consideration of third party involvement in developing transmission solutions, compared to the NEM model. Similarly, some jurisdictions in Europe (e.g. GB) are considering the introduction of mechanisms to support third party provision of transmission assets (see, for example, ¶4.53).

5.84 The decision-making in the NEM is "split" between the TNSPs and the AER in the sense that the RIT-T process is run by TNSPs but it uses AER-defined processes. However, AEMO and AER's role have been mostly advisory.[137] While this process is seen as relatively effective at delivering investments within individual TNSPs' footprint, it differs from the US ISO and European models. In particular, the final decision-making resides with the ISO in the US ISO model, whereas it resides with the national regulators in the European model.

5.85 The difference between the US ISO model and the NEM means that, in the absence of a central entity with visibility over the entire NEM footprint, investments linking different TNSPs tend to be uncoordinated and therefore inevitably challenging to deliver. Finally, one difference between the NEM model and the US ISO and European models is that the regulatory treatment (i.e. investment cost recovery) is consistent across states, driven by the AER.

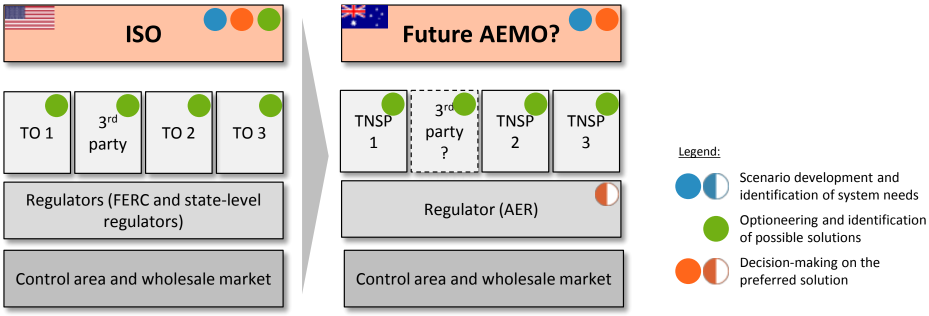
5.86 Despite the differences between the three models we have assessed, there are important parallels between the NEM model and the US ISO model in that both models:

- feature an independent system operator (ISO / AEMO);
- serve to operate within a single country (but multiple states) and in both cases a single system operator oversees multiple transmission operators (TOs/TNPSs); and
- feature a single wholesale market covered by the ISO/AEMO jurisdictions. This means that in the NEM case, the legal "infrastructure" for a cross-state entity already exists and, in principle, could be extended to include a NEM-wide transmission planning role.

5.87 Moreover, the US ISO model 'blueprint' appears to be the closest framework that the NEM could draw relevant lessons from. In Figure 5-6 below, we compare the US ISO model to a theoretical "future AEMO" model, where AEMO takes on a more coordinated system-wide transmission planning role. In this "future AEMO" model, the functions of the SO, TOs/TNSPs and the regulator are aligned more closely to the US ISO model.

[137] This is somewhat analogous to the EU – with national state TSOs (and /or regulatory bodies) undertaking the planning function with an advisory role for ENTSO-E.

Figure 5-6: Future AEMO model: summary of key roles



Source: FTI-CL Energy analysis.

5.88 The theoretical "future AEMO" model seeks to benefit from several attractive features of the US ISO model (and in particular from the specific characteristics of PJM). These attractive features include the following:

- Independence and transparency of the PJM ISO helps ensure that the transmission solutions are objective, credible and in the consumer interest;
- There is a balance between local planning[138] and PJM-wide planning for networks where the benefits are more widely distributed, but all transmission planning, including local assets, is integrated into a single PJM-wide plan;
- The role of a regional transmission planner is combined with the responsibility for balancing over the same footprint – potentially enabling better assessment of trade-offs between different solutions;
- The model supports effective delivery of transmission investments that connect multiple TO footprints (i.e. in terms of investment across TO boundaries);
- Scenarios are developed in a consistent and transparent manner which helps align the market participants' expectations;
- Multiple asset needs (notably the linkages between reliability and economic needs) are rolled into a single integrated plan;
- Appropriate checks and balances are in place (through various committee roles) to validate the overall transmission plan; and

---

138 Local planning is led by TOs, e.g. for assets below 100kV where benefits accrue to physically proximate customers, but must be introduced to the PJM regional planning process.

- Possible solutions from third party developers are considered by the transmission planner (FERC Order 1000 prevents ISOs from intentionally excluding third parties from the transmission planning process).

5.89 Despite these attractive features, the US ISO model cannot be directly transposed to the NEM context. Rather, it is important that the NEM-specific features are appropriately reflected in the design of the "future AEMO" model.

- Giving AEMO a stronger role in identification of system needs and making ultimate decisions about prospective investments seems likely to enable better coordination of investments among TNSPs. Our analysis of the US ISO model indicates that consolidated decision-making and planning based on a consistent set of assumptions across ISO footprint level is an attractive feature, as long as it is supported by well-developed processes to ensure stakeholder buy-in. This could be a helpful precedent to consider in the "future AEMO" model.
- Linkages between AEMO and the insight from individual TNSPs would need to be strengthened (and possibly mandated/incentivised) to ensure that the local knowledge of the networks is appropriately leveraged at NEM level. In other words, TNSPs would need to retain a critical role in identifying options for transmission network solutions based on their local knowledge.
- To ensure AEMO can deliver on a single national plan, AEMO would need to be independent and transparent (and also to be seen as such).
- AEMC would need to retain a critical role of designing the rules that AEMO and other market participants would need to follow in delivering their new roles and responsibilities.
- AER would also need to retain a strong role in determining the regulatory treatment of the cost recovery process (including, for example, assessing the reasonableness of costs and how cost overruns are handled).

5.90 On balance, it seems to us that Australia has a greater opportunity for national transmission planning in contrast to the EU (where decision-making is fragmented) and the US (where between-ISO coordination is complex). Although Australia's energy markets still have much emphasis at the state level, the fact that all NEM regions are part of a single nation with much of the electricity market infrastructure (such as the wholesale market) already undertaken at the NEM level means that there is a greater opportunity to create a model of national planning. This would enable the transmission planning model to determine the investment requirements and enforce the delivery of these investments more easily – rather than being advisory as is currently the case.

5.91 We have also considered whether any of the international precedents could serve as a ‘blueprint’ for the NEM to follow. Based on the analysis of the various jurisdictions in Section 4, and the NEM framework set out in Section 5, it seems that the European model may not be appropriate for the NEM. By contrast, given the parallels between NEM and PJM, it seems reasonable to explore further how some of the attractive features and elements of the PJM ISO transmission planning model could be applied in the NEM, while ensuring that the key features of the NEM are retained. By considering the potential lessons from the US ISO model, the NEM appears to have a good opportunity to move towards a more coordinated transmission planning approach, particularly between TO footprints.

6. Lessons for transmission planning in the NEM

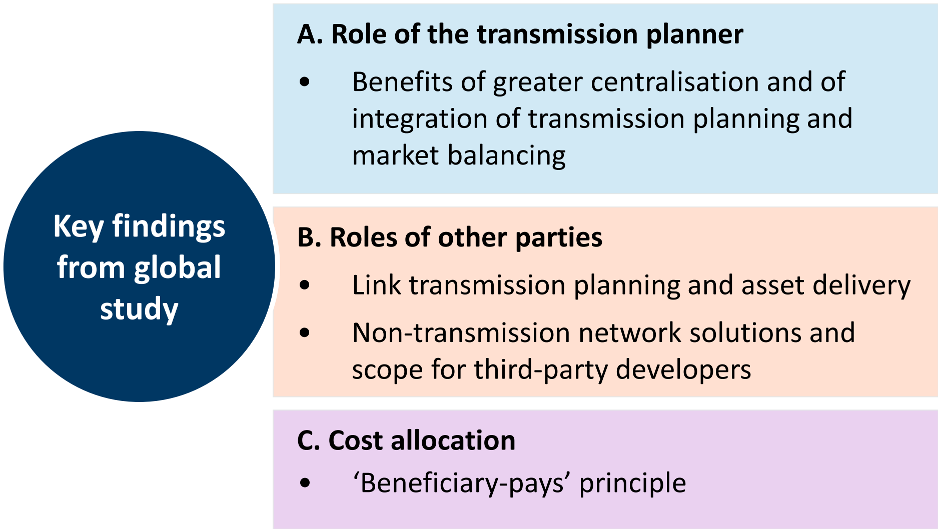
6.1 As shown in the previous sections, the challenge of transmission planning is a global phenomenon. No jurisdiction has been able to resolve fully the issue of how best to plan a transmission network and integrate it with renewables investment, new technologies and the rapid decentralisation of generation. Instead, all jurisdictions are facing to a lesser of greater extent two main issues.

6.2 First, there is an issue of **co-ordination** which exists in two dimensions. One dimension is the difficulty in coordinating "vertically" - between transmission investments and generation investments - given different lead times, and different commercial and regulatory drivers. Emerging technologies such as storage and enhancements in demand-side response will complicate this vertical co-ordination problem further. The other dimension is the difficulty in coordinating "horizontally" - between transmission investments that connect or impact multiple networks - such as investments between neighbouring transmission systems or between higher voltage transmission networks and lower voltage distribution networks.

6.3 Second, the issue of how to **assess** whether it is appropriate to undertake an investment. Transmission assets have long lead times, are relatively costly and might be operational for 40 years (or longer). Furthermore, the inherent network properties of transmission investments mean that benefits are typically dispersed unevenly across network users. Hence, the decision on whether to proceed with an investment now that might still be operating in the second half of the 21st century in an environment where technology, consumer preferences and government policies are evolving rapidly and where benefits are unevenly dispersed is extremely difficult.

6.4 In our report, we examined the approaches adopted in other jurisdictions – mainly the US, GB, Germany and Europe – to these issues. Different jurisdictions take various approaches to this challenge and, to date, there appears to be no single 'best practice' in developing transmission networks. However, as shown in Section 5, the US ISO model 'blueprint' appears to be the closest framework that the NEM could draw relevant lessons from.

Figure 6-1: Areas of recommendations



Source: FTI-CL Energy analysis.
Note: In a separate FTI-CL Energy report, we also suggest additional areas of analysis related to (1) the pros and cons of restricting the evaluation criteria to consumer surplus, and potentially congestion rents, rather than a pure social welfare; (2) the use of a social discount rate in investment tests; and (3) whether investment tests for transmission networks in the NEM should distinguish between asset needs and/or asset types. These suggestions are not repeated in this report.

A. Role of the transmission planner

6.5 When we examined the approach to the NEM transmission planning, we found that a key issue under discussion was the extent to which the transmission planning and decision-making roles should be undertaken at a 'local' or state-wide level or whether it was a better to have a wider geographical remit.[139] This issue has emerged particularly in transmission planning in the US and in Europe.

[139] This issue of at what level to undertake the planning function is also likely to become increasingly relevant between transmission and distribution networks. The impact of the decentralisation of energy means that distribution networks are likely to become increasingly active. An implication of this is that there is likely to be increasing potential for substitutability between investments in the transmission and distribution networks – meaning there is a greater need to co-ordinate and/or integrate planning functions.

6.6 We find that there may be benefits to giving the market operator a centralised transmission planning role such that the planning footprint and the balancing footprints are the same (NEM-wide). This is because the changes in the energy markets increasingly make a case for considering a more centralised planning of transmission than has historically been the case. Centralising the transmission planning function over the same footprint as the existing wholesale market may also enable greater coordination of transmission and generation development.

6.7 In network planning in general, there is an inevitable tension between local planning and national planning. A more local transmission planner (for example a regional TO) has the advantage of having a more in-depth understanding of the network within its jurisdiction and is likely to be better at stakeholder management. However, such a local planner will, by design, concentrate on planning the network within its geographic scope and is less likely to divert its planning resources to planning how the network might interact with neighbouring networks. Often commercial and political pressures encourage this behaviour – if it is seen as responsible for "keeping the lights on" in its geographic footprint, then it will invest accordingly in its area. Equally, many regulatory regimes reward a greater roll out of assets – this increases a transmission planner's tendency to build more within its 'patch' with less consideration of a system-wide view.

6.8 Historically, in an environment where large-scale thermal generation is being deployed to meet growing demand (with broadly similar cost drivers across regions), a more localised transmission planning approach would probably be more beneficial, given the clear transmission requirements.

6.9 However, changing energy demand and supply fundamentals, driven by greater renewables generation, aging thermal generation and slowing demand growth – together with advances in cable technology that lower the costs of transmission – means the benefits of greater integration across networks are potentially higher now than they were previously. In this purview, therefore, a transmission planner with a wider geographic scope might be a better approach to account for the cost and benefits across a system-wide view.

6.10 The potential downsides of less localised planning would need to be mitigated to ensure that the local knowledge of the TNSPs is not inadvertently lost. In particular, we envisage that the linkages between AEMO and the insight from individual TNSPs would need to be strengthened (and possibly mandated and/or incentivised) so that the local knowledge of TNSPs is appropriately leveraged at NEM level.

Recommendation #1: Consider the potential for a system-wide transmission planning function with a mandatory rather than advisory role.

6.11 Coordinating between generation and transmission investments is intrinsically challenging. First, generation and transmission investments have different lead times (with generation investments being typically shorter relative to the latter). Second, generation and transmission investments are brought forward by different drivers – generators attempt to make siting decisions in response to price signals and the availability of transmission assets (as well as subsidies if available), while transmission investments are typically regulated and require more coordinated and intensive planning efforts.

6.12 To overcome these coordination issues, the system operator, in its function of a transmission planner, could become more 'proactive' in terms of coordinating generation and transmission investments. In other jurisdictions, ERCOT (Texas) and MISO, there are precedents in coordinating transmission and generation investment, with a view to delivering a particular policy (new wind generation in ERCOT through the development of Renewable Energy Zones) or with a view to minimising overall costs (MISO's Regional Generation Outlet Study). In Germany, an offshore Grid Development Plan is used to coordinate multiple offshore wind farms as a 'cluster' to be connected to the onshore grid via a single link.

6.13 It appears that the joint oversight of both wholesale market operation and balancing, together with the transmission planning function, enables a more holistic, coordinated and efficient approach to transmission and generation development.

B. Stakeholder involvement

6.14 If the existing transmission planning framework in the NEM were to be adapted and shifted closer to the US ISO model, we consider that the roles of various would need to be clarified and refined, such that Australia-specific features of the framework are preserved.

6.15 There are two main areas that would need to be considered: first, the roles of the SO (AEMO) and the regulator (AER) in ensuring that the delivery of a transmission asset (or transmission solution) is clearly linked to the transmission plan may need to be refined. Second, the provision of non-network solutions (including by non-TNSPs, i.e. third parties) would also need to be considered. These two areas are discussed in turn below.

Link between transmission planning and delivery of asset

6.16 In the NEM the costs used in the assessment of a transmission investment at the planning stage are not necessarily linked to the actual costs that are ultimately recovered from consumers. Compared to the NEM, other jurisdictions tend to have a stronger link between the transmission plan and delivery of the asset. In the US, the cost recovery process is led by the ISO which sets the cost recovery as part of the planning process (although investment cost recovery varies state by state and there is no single consistent approach used by all ISOs). In Europe, this is typically led by the regulator, which determines the costs as part of a regulatory regime (although, again, investment cost recovery varies by country).

6.17 The SO and/or regulator tend to be significantly involved in the assessment and approval of transmission investments, seemingly to facilitate greater information coordination, to provide an independent view on transmission planning, and for additional/complementary verification of the costs and benefits.

6.18 The SO and/or regulator also tend to continue monitoring the transmission project (for example Ofgem would hold the developer to the original cost estimates – with any ex-post divergence requiring robust justification from the developer). Overall, the ex-post involvement of a regulator or the SO needs to balance a trade-off between accountability (e.g. to incentivise developers to accurately estimate costs) and preventing undue delays to investment.

6.19 The transmission planning process in the NEM could benefit from establishing a stronger link between the outcomes of the transmission plan and the actual delivery of the transmission asset. This would ensure that the proposed transmission asset will be built according to the expected timings and cost as per the plan. In this respect, we consider that AEMC would retain a critical role of designing the rules for AEMO and other market participants to follow in delivering their new roles and responsibilities.

Recommendation #2: Consider how transmission planning is linked to the actual delivery of the asset.

Non-transmission network solutions and scope for third-party developers

6.20 As the role of the transmission planner changes in tandem with the energy sector, the transmission planner should also consider alternatives to transmission solutions led by incumbent TNSPs. This may be utilising non-transmission solutions and/or relying on third-party developers.

6.21 First, the transmission planner should also consider credible alternatives to transmission investments such as generation, distribution network investments, or demand-side response.

6.22 Second, third-party developers may be able to provide innovative and efficient solutions to transmission needs, which may ultimately be at a lower-cost and/or higher quality than incumbent solutions. This may be encouraged by the transmission planner through competitive procurement processes, or to facilitate more regulated or partially-regulated interconnectors.

6.23 In the US, FERC Order 1000 has been key in enabling non-TO parties to submit proposed solutions (which may be both transmission and non-transmission solutions) to identified needs and to build and operate such assets. In GB and in Europe, independent developers can act as 'promoters' of cross-country interconnectors, and develop, construct, own and operate the assets.

6.24 As transmission planning improves in the NEM, this might open the scope for more third-party developers to add greater competitive pressure on the identification of alternative solutions and/or on cost-reductions.

Recommendation #3: Ensure non-network solutions are considered, particularly when evaluating options for meeting an identified need.

Recommendation #4: Consider how third-party developers should be included in transmission planning, to encourage lower cost solutions.

C. Cost allocation

6.25 Transmission planning has had to evolve, in part because of 'diluting' price signals which have obscured efficient siting decisions of network users. This means that any improvements to the electricity market design that result in more efficient price signals could better inform transmission planning – by incentivising market participants to make more efficient decisions, and to more accurately reveal the need and value of potential transmission investments.[140]

---

[140] The analysis undertaken in this report takes as given the current wholesale market design used in the NEM (e.g. a single price area across each region and non-firm access for generators to the grid). Changes to wholesale market design could affect market participant behaviour – for example, more accurate locational price signals to generators (such as those operated in the US markets) have the potential to result in more optimal siting decisions and therefore more efficient transmission network investments. However, a discussion of potential changes to the NEM wholesale market design is beyond the scope of this report.

6.26 In this respect, the beneficiary-pays principle is seen by many economists to be the most appropriate approach to allocating costs among stakeholder groups. This is because it places the costs of an investment on the party (or parties) that benefits from the investment and allocates the risks of an investment to those most incentivised (and therefore best placed) to manage them, and also because it makes the cost allocation consistent with the operations of the rest of the market. However, the application of this principle can, in practice, be complex.

6.27 In the NEM, the cost of transmission investments is predominantly recovered from end-user consumer tariffs. Generators only pay for the TNSP's costs to connect them to the nearest appropriate point on the transmission network. This might potentially limit the effectiveness of how transmission costs are allocated to the relevant beneficiaries.

6.28 Indeed, the FERC Order 1000 mandates a beneficiaries-pay approach to be used for all regulated assets. Examples from Argentina ("Public Contest"), SPP and ERCOT illustrate the complexity and trade-offs involved in allocating costs and benefits among market participants. However, there is no single 'best' approach that could be replicated across all jurisdictions.

6.29 There are also examples of interconnectors where the beneficiary-pays principle emerges directly from the participants themselves (i.e. without planners' involvement). This occurs where beneficiaries of potential interconnectors find routes to provide financial support to underpin the construction of interconnectors that they believe will be in their economic interest.[141]

Recommendation #5: Explore how the beneficiary-pays principle should be reflected in the cost allocation arrangements, so the costs and benefits of transmission investment are allocated fairly.

141 For example, NorthConnect (a planned link between Norway and Scotland) is likely to facilitate greater exports from Norway and is being developed by Nordic generators , while Piemonte Savoia (a France-Italy link) is promoted by a group of Italian energy-intensive industrial customers that would be likely to benefit from increased imports of low cost electricity from France into Northern Italy. Arguably, in GB, the regulator, Ofgem, sanctions customer support of interconnector projects if it considers that GB consumers will benefit on account of increased imports.

Appendix 1
International case studies on transmission planning

A1.1 This Appendix sets out the international experience of transmission planning, and where relevant, highlights common practice.

A1.2 We have also identified potential areas where precedent from other jurisdictions may provide informative lessons for the NEM transmission planning.

A1.3 The following case studies have been considered as part of this appendix:

- GB – Strategic Wider Works/NOA, Interconnectors and OFTOs;
- US – NYISO, PJM, interregional transmission assets and renewable zones;
- Europe – ENTSO-E's TYNDP; and
- Germany.

A. GB transmission planning

A1.4 This section summarises the key features of transmission network planning across different types of assets in GB.[142]

A1.5 A single SO, the National Grid System Operator ("NGSO") operates across the whole of the GB transmission network. There are three TOs that own and operate the transmission network in their respective regions: National Grid Electricity Transmission ("NGET")[143] covers England and Wales, Scottish Power Transmission ("SPT") covers southern Scotland, and Scottish Hydro Electric Transmission covers northern Scotland and the Scottish islands. A single body, Ofgem, regulates the electricity system in GB.

---

142 The United Kingdom comprises England, Wales, Scotland and Northern Ireland. England, Wales and Scotland together make up Great Britain ("GB"). Northern Ireland's electricity network is separate from that of GB. The electricity network described in the following subsection focuses on the GB electricity network only.

143 In England and Wales, the SO and TO are integrated but are functionally separated (and are due to be legally separated in 2019).

A1.6 Figure A1- 1 sets out an overview of the main roles and responsibilities of the main parties in relation to transmission planning, and lists some of the key outputs produced by different parties at each stage.

Figure A1- 1: Overview of key roles and responsibilities in GB

Project Development Framework		1 Scenario development	2 Identify system needs	3 Identify and select solution	4 Funding the delivery
GB - SWW	ROLE	NGSO	TO identifies a need, reviewed by Ofgem	TO creates a project plan, and provides required information. SO performs CBA. Ofgem oversees process and reviews submissions	TO
	OUTPUT	FES	Needs case submission (TO); Needs case assessment (Ofgem)	Detailed project submission by TO; Following selection of preferred option, TO submits Project Assessment and Ofgem publishes statutory consultation	Independently verified report after construction
GB - NOA	ROLE	NGSO	NG SO	NG SO works with TO to identify options and performs 'least-worst regret' analysis; NG SO publishes non-binding findings	n/a
	OUTPUT	FES	ETYS	NOA Report	n/a
GB - OFTOs	ROLE	n/a	Generator – reviewed by Ofgem	Generator build: generator designs project and Ofgem runs competitive tender OFTO build: OFTO designs project and Ofgem runs competitive tender	Generator Successful OFTO bidder
	OUTPUT	n/a	Notification of Qualifying Project	Tender process where Successful Bidder selected	Transfer Agreement
GB - Interconnectors	ROLE	Ofgem	3rd party developers	Ofgem; 3rd parties; SO	3rd party builds asset and Ofgem reviews & finalises c&f values
	OUTPUT	Opens application window	n/a	System impact assessment produced by SO, third parties consulted at various assessment stages and C&F regime granted by Ofgem	n/a

Regulator | SO | TO/3rd party | Generator | Load Serving Entity

Source: FTI-CL Energy analysis.

A1.7 In this section, we discuss four transmission planning processes in GB:[144]

144 In GB, most transmission planning and investment is assessed during the price control period for the regulated TOs, and this sits outside of these four planning processes. These are largely network deepening investments and tend to include a large number of smaller-scale individual investments undertaken by the incumbent TOs, subject to standard regulatory processes. For the purposes of identifying international precedents in relation to the RIT-T and the NEM, it is more relevant to focus on specific large-scale investments, as opposed to small-scale investments that occur as part of the regular price control cycle.

- The **SWW** process allows the incumbent GB TOs to propose large transmission investments. The SWW process, led by TOs, has been developed to allow for the uncertainty around the timing and cost of large transmission projects that may be required during a price control period;[145]
- The **NOA** is run by National Grid System Operator ("NGSO") to select preferred transmission investment options to meet identified needs. The recommendations of the NOA process are non-binding. Unlike SWW, the NOA happens annually. The introduction of the NOA process is a relatively recent change to the GB transmission planning regime recommended by Ofgem's ITPR project. The ITPR is summarised in Box A1- 1 below.
- The **OFTO** process is a competitive tender to assign a transmission operator and connect offshore wind farms to the mainland GB network. Like the SWW, it is developer-led, as Ofgem is mandated to connect any new generators to the GB network.
- **Interconnectors** between GB and the rest of Europe are proposed and developed by TOs or third parties, and are subject to Ofgem's Cap and Floor regime. Like the OFTO process, this is developer-led.

A1.8 Ofgem has also begun to introduce competitive procurement of onshore transmission, focusing on new, separable and high value investments. Ofgem developed various models for Competitively Appointed Transmission Owners ("CATOs"), but this development was put on hold in early 2017 owing to uncertain timing of the necessary legislation. This model would remove the monopoly of the three current Transmission Operators over onshore GB transmission investment.

[145] The SWW process was intended to assess proposals for new transmission assets within the RIIO-T1 price control period (1 April 2013 to 31 March 2021).

A1.9 In the absence of the CATO legislation, Ofgem has proposed alternative (temporary) models, known as Competition Proxy[146] and Special Purpose Vehicle ("SPV") models, and in 2017 consulted on applying these models to one specific project (Hinkley-Seabank). Ofgem has confirmed that it intends to "*consider the Competition Proxy and SPV delivery models for all future SWW projects that are subject to a needs case assessment*" during the current price control.[147]

Box A1- 1: Integrated Transmission Planning and Regulation ("ITPR") Project

In 2012, Ofgem began to consider the interaction between the existing GB onshore, offshore and interconnector regulatory regimes via the ITPR project.

The project's stated purpose was to meet two key objectives: (1) to ensure the transmission network as a whole is planned in an economic, efficient, and coordinated way; and (2) to ensure that asset delivery is efficient, and consumers are protected from undue costs and risks.

In 2015, the ITPR concluded that the following changes were necessary: the SO's role was expanded to include the NOA process described in this section. In addition, Ofgem expressed its intention to extend the use of competitive tendering from the OFTO process to onshore transmission assets. On interconnectors, Ofgem concluded that the current developer-led Cap and Floor approach was fit for purpose, and signalled its intention to open more Cap and Floor application windows in the future.[148]

---

146 In the Competition Proxy model, Ofgem would set TOs' allowed revenue in line with the "*outcome we consider would have resulted from an efficient competition for construction, financing and operation of the project*". In the SPV model "*the incumbent TO would run a competition for the construction, financing and operation of the project through a project-specific Special Purpose Vehicle*". In both models, the objective is to achieve benefits to consumers through reducing the transmission costs.

147 Ofgem (2018) Update on competition in onshore electricity transmission (23 January 2018).

148 The first Cap and Floor window, which invited developers to propose new interconnector projects, was opened in 2014 (Ofgem, Cap and Floor – first application window submissions, accessed at: https://www.ofgem.gov.uk/publications-and-updates/cap-and-floor-first-application-window-submissions), i.e. prior to the ITPR project being concluded. The second Cap and Floor window was opened in late 2015, with developers being invited to submit their proposals during 2016. (Ofgem, Decision to open a second Cap and Floor application window for electricity interconnectors in 2016, accessed at: https://www.ofgem.gov.uk/publications-and-updates/decision-open-second-cap-and-floor-application-window-electricity-interconnectors-2016).

The main results of the ITPR recommendations have, thus far, been an enhancement of the powers of the SO, though Ofgem retains the role of final decision-maker in transmission planning.

A1.10 The following sub-sections focus on each of the different transmission lifecycle stages in turn and describe the main activities undertaken by the relevant parties.

Scenario development

A1.11 This subsection explains the scenario development for the GB transmission planning processes.

SWW and NOA

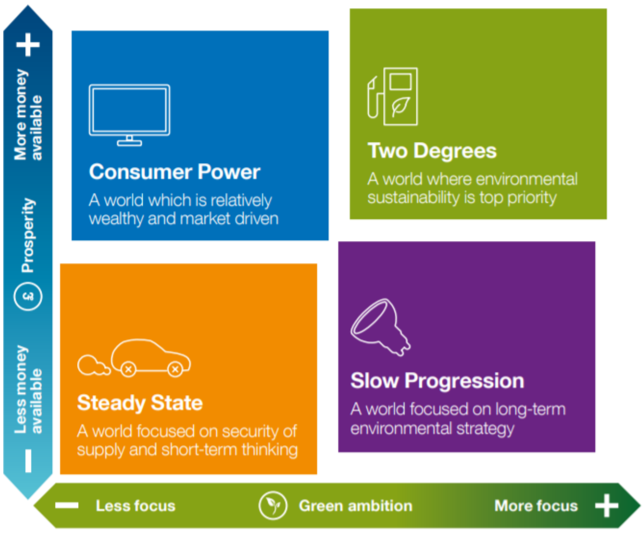
A1.12 The SWW and NOA processes make use of the system operator's Future Energy Scenarios ("FES") for scenario development.

A1.13 The FES are a set of four future states of the world, or scenarios, published annually by the NGSO.[149] The scenarios are not intended to identify the 'most likely' outcome for the GB energy market, but rather to articulate a credible range of outcomes that are plausible, depending on external factors such as policy and market factors. In 2017, the NGSO developed four scenarios, where each scenario considers the likely pathways if the economy was more prosperous (i.e. market factors) and/or had greater incentives and desires to be environmentally sustainable (i.e. policy factors) compared to the base case (where the current level of progress continues). The scenarios for FES 2018 published on 12 July 2018 will have different scenario 'matrix': one dimension of the 'matrix' will represent different combinations of energy decentralisation (instead of economic prosperity as was the case in FES 2017). The 'green ambition', or speed of decarbonisation, remains in the FES 2018. NGSO does not attach probabilities to these scenarios. These forecasts are developed for up to 2050.

[149] National Grid is GB's European Network of Transmission System Operators for Electricity ("ENTSO-E") representative. ENTSO-E facilitates the coordination of electricity transmission projects across Europe, and is further discussed later in this appendix. National Grid is not mandated to undertake projects published in ENTSO-E's Ten Year Network Development Plan ("TYNDP"). The TYNDP uses different scenarios to National Grid's Electricity Ten Year Statement ("ETYS") and NOA.

A1.14 The four FES in 2017 are illustrated in Figure A1- 2 below:

Figure A1- 2: National Grid Future Energy Scenarios 2017



Source: National Grid, Future Energy Scenarios, July 2017.

A1.15 The four FES in 2017 were:[150]

- **Steady state:** represents a state of the world where the current level of progress and innovation continues;
- **Consumer power:** represents a state of the world where consumers are not inclined to become environmentally friendly, there is high demand for innovation driven technology, and energy supply is focused on low cost generation;
- **Slow progression:** represents a state of the world where the economy wants to become more environmentally friendly and there is cost effective policy intervention, but low economic growth limits the money available to achieve these objectives; and
- **Two degrees:** represents a state of the world where consumers make conscious environmentally friendly choices, there is investment in low carbon energy, and the UK meets its carbon emission reduction targets.

150 These scenarios are subject to change, reflecting updated forecasts. For example, the 2016 FES were: "No progression"; "Consumer power"; "Slow progression"; and "Gone green".

A1.16 In producing the NOA, the main responsibilities sit with the SO, but TOs also have a range of responsibilities in supporting the analysis. These include, for example, the technical analysis of network boundary capabilities, responsibility for proposing reinforcement options, submitting cost information, providing system access requirements, as well as facilitating stakeholder and environmental engagement.

A1.17 It is not mandatory to use the scenarios outlined by the NGSO in FES in assessing whether an asset should be commissioned or a particular regime granted (e.g. such as the Cap and Floor regime for interconnectors), but the scenarios are commonly used by a range of stakeholders – i.e. they are part of the 'standard' scenarios that market participants refer to, or make use of, in their analysis. FES scenarios often represent 'core' scenarios used by market participants, with additional sensitivities developed to stress test project viability beyond the core scenario envelope (e.g. driven by high decentralisation of power generation, decarbonisation of transport or heat, etc.).

A1.18 However, adhering to a single set of scenarios enables a greater degree of coordination and the development of a common view of the potential pathways across the market. Such common views can in some cases support the development of business cases for transmission assets: for example if the NOA highlights a particular asset need, that asset is more likely to be viewed favourably in an SWW test.[151]

OFTOs

A1.19 As the need for OFTO assets is driven entirely by generators, and the selection of a preferred OFTO is largely a cost minimisation exercise, no scenario development is necessary.

[151] Ofgem lists NOA projects that have gained a "proceed" recommendation as potential SWW projects (Ofgem, Current and future potential SWW projects, accessed at: https://www.ofgem.gov.uk/electricity/transmission-networks/critical-investments/strategic-wider-works).

Interconnectors

A1.20 Interconnector developers, who choose to apply for the regulated Cap and Floor regime in GB,[152] select a set of plausible scenarios that reflect key economic drivers between the interconnected countries. Ofgem will then assess the developers' submissions against their own set of plausible scenarios. Ofgem guidance does not mandate what scenarios should be used, but states that scenario development should consider the latest national scenarios (FES in GB) as well as the scenarios set out in the European Network of Transmission System Operators for Electricity's ("ENTSO-E") CBA guidance.[153]

A1.21 In practice, Ofgem forms its own view on the most relevant scenarios to consider in its assessment of interconnector applications. For example, in the most recent assessment of Window 2 projects, Ofgem relied on a combination of Base, Low and High scenarios, but also assessed sensitivities to interconnector-specific factors such as changes to thermal generation in GB and policy changes (e.g. removal of carbon price support in GB).[154]

Identify system needs

A1.22 The entity responsible for identifying a system need differs across asset types. However, the regulator will often have oversight of the process.

A1.23 In the **SWW** process, the TO identifies a need for an investment in its own network by submitting an initial needs case assessment to the regulator, Ofgem, which details a high-level option, but this submission takes place before detailed development and planning consent applications are undertaken. This submission should also identify a need to improve existing capacity and/or security.

---

152 Merchant interconnectors are assessed through a separate process, and require exemptions from certain EU-wide regulations. The focus of this report is on regulated GB interconnectors under the Cap and Floor regime.

153 Ofgem (May 2014) The regulation of future electricity interconnection: Proposal to roll out a Cap and Floor regime to near-term projects.

154 Ofgem (June 2017) Cap and Floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors.

A1.24 As explained above in ¶A1.7, SWW assets are distinguished from other smaller-scale transmission investments which are known as wider works outputs, which transmission operators propose (and may receive regulatory allowance for) as part of the standard price control process. The regulator gives an allowance for smaller-scale transmission projects, subject to a range of uncertainty mechanisms and delivery of the outputs (e.g. boundary capacity increase). In England and Wales, assets costing below £500m fall outside of the SWW process:

- For assets that are smaller than £100m and no planning consent is required, an allowance is automatically adjusted by multiplying the increase in capacity by an agreed unit cost.
- For assets between £100m and £500m, an allowance will be calculated by the regulator if two conditions are met: first, there is a positive cost-benefit assessment against a majority of the scenarios and sensitivities, and, second, the transmission solution is supported by user commitment from more than one customer.

A1.25 SWW projects are defined as larger projects (above a certain cost threshold)[155] that face higher uncertainty around the timing and cost, and therefore cannot be identified and/or approved during the standard price control process. SWW projects are 'triggered' when more information has been revealed over the duration of a price control period, whereas wider work outputs are set by Ofgem as part of the regulatory settlement.

A1.26 The **NOA** process, unlike the SWW, is driven by the SO and is a relatively new process introduced in GB in 2015 (the first NOA Report was published in 2016). Under the NOA process, transmission needs over the next 10 years are identified via National Grid's Electricity Ten Year Statement ("ETYS"), which takes inputs directly from the FES. National Grid publishes the ETYS annually. The requirement to publish this document is driven by the European Commission's Third Energy Package (a set of EU regulations that aim to coordinate the energy legislation across Europe).[156] Needs are identified under the NOA in the form of future expected constraint costs across specific GB boundaries.

155 £50m in northern Scotland, £100m in southern Scotland, and £500m in England and Wales.

156 National Grid, Electricity Ten Year Statement 2017, November 2017.

A1.27 The investment needs for **OFTOs** are led by offshore generators, as Ofgem is mandated to connect all offshore generators with the GB network. The scale and type of the transmission investment need is also driven by the size of the wind farm and the applicable security of supply standards.

A1.28 **Interconnectors** in GB are primarily market-driven in the sense that private developers identify and develop business cases for each interconnector. The developers can be either entirely private entities, or they can be consortia linked to the incumbent TOs. Thus, there is no formal GB-specific process for identifying an investment need in interconnectors. In practice, potential developers seek to identify boundaries between GB and neighbouring countries by focusing on the congestion revenue potential (i.e. the arbitrage between the wholesale prices in GB and Europe). This has led to a large number of projects being proposed by a number of developers, including to Norway, Denmark, France, Belgium, Germany and Ireland.

A1.29 The NOA has, in its 2017 and 2018 reports, commented on the future need for interconnectors in GB. For example, in 2017, it sought to identify the 'optimal level of interconnector' under one of the FES scenarios, whereas in 2018, the NOA reported a level of interconnection capacity that would "*provide the lowest risk for GB consumers*".[157] Neither of those studies, however, has had a material bearing on the projects under development (and indeed, it is not intended to do so – as noted in 2018, the analysis "*does not provide any project-specific information and the output of the analysis does not determine or have any impact on a project's viability*").[158] For example, in the 2017 NOA, interconnection to Iceland was identified (a finding that was criticised by a number of commentators) – and yet no significant progress has been made in that respect. Conversely, other projects, including interconnectors to Germany and Norway, have progressed, seemingly above the level of 'optimal' interconnector volume.[159]

---

157 NOA 2016/17, section 6.5.1. NOA 2017/18, pp 104.

158 NOA 2017/18, Section 6.1.1

159 NOA 2016/17, Figure 6.2, Projects that have progressed are NeuConnect and NorthConnect.

A1.30 The NOA methodology for interconnectors has been updated every year since the first NOA publication in 2015/16, and is due to be updated again in the NOA 2019. The key changes in the draft methodology published in April 2018 include a stronger focus on ancillary services opportunities and system operability risks posed by interconnectors (over and above the socio-economic welfare, capital costs and reinforcement costs).[160]

Identify options and select solution

A1.31 In GB, different investment tests are designed for different asset types.

A1.32 For assets assessed under the **SWW**, a CBA is run by the TOs (and submitted to the regulator for assessment and approval). The CBA compares network reinforcement to several counterfactual options including a 'no-build' option. The costs and benefits are estimated over the lifetime of the investment asset. The expected project cost should be less than the cost to consumers relative to the 'no-build' option.[161] SWW projects are assessed purely from the perspective of consumers. This is consistent with Ofgem's first statutory duty, to *"protect the interests of existing and future consumers"*.[162] The discount rate is set at the regulated level of the WACC. Ofgem assumes all transmission assets considered under SWW have a useful life of 40 years, and uses this as its fixed time horizon.

---

160 Draft NOA Report Methodology, April 2018, Section 3.

161 *"The CBA will evaluate the economic net benefit to consumers of a network reinforcement compared to the counterfactual that no reinforcement is undertaken."* Ofgem (November 2017) Guidance on the Strategic Wider Works arrangements in the electricity transmission price control, ¶2.27.

162 Ofgem (2014) Our strategy, pp 4.

A1.33 For assets assessed under the **NOA**, the SO collects potential technical solutions proposed by the TOs, and may also add its own solutions. SO runs a CBA using a single year least-worst regret approach to select the preferred option.[163] The discount rate is based on the published Social Time Preferential Rate ("STPR") which is 3.5% in real terms (and has been since 2003). The NOA, in line with the approach of the SWW assessment, uses a time horizon of 40 years.

A1.34 While the NOA's recommendations are non-binding, there is a strong connection between the NOA and SWW. A project given a "proceed" recommendation in the NOA is considered by Ofgem as a "potential SWW project",[164] and Ofgem expects TOs to use the NOA alongside their own analysis when making an SWW submission.[165] In this sense, a recommendation via the NOA process makes an SWW application more likely to succeed. Moreover, if a particular transmission investment has been approved via the SWW process, it is subsequently removed from the NOA as a possible option (as the project has been 'approved', it is taken as a given by the NOA assessment).

A1.35 Ofgem runs a competitive tender for **OFTOs** to identify the lowest cost bidder (over a 20-year period) that meets all operational and financial requirements. These are triggered by the offshore wind farm developer, who requests Ofgem to run a tender to identify an OFTO. The winning bidder owns and operates the asset linking to the offshore wind farm. In the competitive tender, bidders select a revenue stream that covers the cost of owning and operating the asset. As this is a competitive tender for an asset that will be built independently of the cost of the winning bid (as this is 'generator-led' transmission investment), Ofgem does not consider the benefits. Bidders also select their own discount rate in their bids which are not made public.

---

163 This involves calculating, for each transmission investment option (including 'do nothing' option), the 'worst congestion costs' across four pre-defined scenarios, then selecting the option with the lowest 'worst congestion cost'. This approach avoids attributing a direct probability to each of the scenarios, but implicitly gives the greatest weight to the most 'negative' scenario in terms of total congestion impact.

164 Ofgem, Strategic Wider Works, accessed at https://www.ofgem.gov.uk/electricity/transmission-networks/critical-investments/strategic-wider-works.

165 Ofgem, Guidance on the Strategic Wider Works arrangements in the electricity transmission price control, RIIO-T1m 24 November 2017.

A1.36 For **interconnectors**, Ofgem allows potential interconnectors to apply for regulatory support, which involves setting a cap and a floor on revenues.[166] Under this regime, interconnectors are able to rely on customer support in case their annual revenue falls below a (regulator-determined) 'floor'. Conversely, interconnectors must return any excess revenues to consumers if their revenues exceed a 'cap'. In between the floor and cap levels, the interconnectors retain the revenue as earned, i.e. they effectively operate within a "merchant" band.

A1.37 Ofgem is responsible for determining the cap and the floor levels that apply to the interconnector revenues (including congestion revenues and any other revenues, such as ancillary services, that the interconnector may be able to earn). This assessment typically only takes into account 50% of the interconnector revenues as a proxy for the revenues attributable to the GB side of the interconnector[167] and none of the revenues in the connecting country. This is because Ofgem has no jurisdiction over, or obligation to, the non-GB country that is connected via the interconnector.

A1.38 Ofgem adopts a relatively mechanistic approach to setting cap and floor levels. The cap is set at an approximation of a reasonable return to shareholders (linked to a notional cost of equity) and the floor is set to approximate the cost of debt. The CBA is performed from a GB net consumer welfare perspective. A social discount rate is used, but a developer can provide a different rate with acceptable justification. The time horizon considered for interconnectors is the duration of the Cap and Floor regime, 25 years.

A1.39 In addition to determining the cap and the floor levels, Ofgem is also responsible for assessing whether or not an applicant project should be granted the regulated regime. Ofgem bases its decision primarily on the assessment of the GB consumer welfare impact, in line with its statutory duties: it takes into account the changes in the wholesale prices in GB (typically, they are reduced as a result of increased interconnection), as well as additional system costs (e.g. due to grid reinforcements, if any, needed as a result of the interconnector), and any extra revenues (or payments) expected from the design of the Cap and Floor regime itself. Ofgem also estimates the impact of the interconnector on GB overall (i.e. including the producer surplus), but this does not feature in its final decision process.

---

166 As noted in FN152 above, merchant interconnectors, i.e. without any regulatory underwriting, follow a different process.

167 However, the assessment can be based on a different percentage, when suitably justified by the applicant.

A1.40 The additional benefits associated with multi-purpose projects may also be considered in identifying an optimal solution. The FAB Link interconnector between France and GB is an example of a multipurpose project. Ofgem considered the option value of being able to connect to future tidal generation in the States of Alderney in its Initial Project Assessment.

A1.41 NOA's CBA analysis is linked to the FES. However, for the other GB regimes, it is not necessarily the case that the FES are used in the CBA. Instead a set of reasonable scenarios should be developed. It is often the case that these scenarios are founded from the FES, and that strong justification is required if the FES are not used.

A1.42 Ofgem plays a key role under each regime. This role includes for example being responsible for overseeing and implementing the investment selection process, approving investments, and monitoring project completion.

A1.43 In terms of the disputes resolution process, Ofgem typically opens each transmission project to multiple rounds of public consultations providing opportunities for debate.[168] Outside of public consultations, disputes can be referred to Ofgem, who will then determine an outcome.[169]

Funding the delivery of the asset

A1.44 The costs of transmission assets proposed via the SWW and OFTO processes are socialised, and recovered via transmission charges paid by customers.

- The cost of an approved SWW asset is included in the RAB of the respective TO, and recovered via the price control. However, there is a desire from Ofgem to introduce competitive processes into the delivery of SWW projects, for example through Competition Proxy and SPV models (see ¶A1.9 above).

---

168 For example, the SWW has three rounds of public consultations for each of the initial needs case, the needs case and the project assessment.

169 Ofgem (2017), Ofgem guidance on the determination of disputes for use of system or connection to energy networks.

- An OFTO's revenue is defined (separately from the price control) over its 20-year period (known as the Tender Revenue Stream), which is set as part of its tender process.[170] Any cost adjustments that OFTOs experience are closely monitored by Ofgem and are not necessarily approved. Ofgem seeks to ensure that only efficient costs are passed through to consumers and may refuse the OFTO to recover portions of costs that, in Ofgem's view, are due to the procurement or delivery inefficiencies.

A1.45 An interconnector earns revenues by capturing congestion rents, subject to its regulated cap and floor levels, and may also earn additional revenues (e.g. from the capacity market or from ancillary services). Typically, Ofgem expects interconnectors under the Cap and Floor regime to recover their costs from the congestion rent (i.e. without consumer support). However, the design of the regime enables consumers to benefit from any above-cap revenues (which are clawed back and returned to consumers via lower transmission charges), and it also exposes consumers to the risk of 'topping up' interconnector revenues through floor payments (again, this is recovered from transmission charges).

A1.46 Ofgem often plays an active role in monitoring the delivery of assets. Under the Cap and Floor regime, the regulator will first set indicative cap and indicative floor values (at the Initial and Final Project Assessment stages), but will only confirm the final values and update the interconnector licence revenues once the project has been delivered (when actual costs are known), through a Post-Construction Review. Any significant change between projected and actual costs must be justified and shown to be efficiently incurred.

A1.47 Ofgem also takes an active role under SWW after the approval of a project. During construction, Ofgem monitors incurred expenditure against permitted expenditure, and applies an efficiency incentive rate to the difference such that the TO is exposed to a proportion of overspend or retains a proportion of underspend. Following the completion of the project, Ofgem will compare the delivered output and time to delivery against the granted licence, and may impose a financial penalty if there is a significant difference.

---

170 Selected OFTOs' revenues (Tender Revenue Streams) are adjusted for, inter alia, availability bonuses or unavailability penalties, pass through of certain approved costs, inflation, capacity income, and certain market rates. Selected OFTOs must also share any gains made from the refinancing of debt with consumers. As a default, this is shared 50:50. Selected OFTOs are liable for any costs associated with decommissioning, which are determined by the legislation at the time of the tender. Should legislation change between then and the time at which the transmission asset is decommissioned, the selected OFTO may pass on any additional costs to consumers.

A1.48 Ofgem does not explicitly coordinate the development of cross-country transmission assets with other European countries, since it can rely on the independent development of projects which are then subject to the regulation of both connected countries. For example, new interconnectors between GB and France are subject to regulation by both Ofgem and the French regulators (CRE). Each of the two regulators set their own rules for the interconnector; so interconnectors can face a Cap and Floor regime in GB (e.g. for 50% of the link), and a fully regulated regime in France (for the remaining 50%). However, there are additional rules in place that enable cross-TSO cooperation post-delivery of the asset, such as inter-TSO programme enabling better compensation among TSOs within Europe.

A1.49 With respect to cost allocation, the options are limited in GB as there is no zonal (or nodal) pricing. The costs of most transmission investments (with the notable exception of interconnectors) are socialised among consumers. Ultimately, it is the consumer who bears the cost risk in GB through transmission usage charges, except when an interconnector is not part of the Cap and Floor regime.

A1.50 GB regulation also includes a specific approach to ensuring appropriate incentives are in place for transmission operators to maximise their availability (and benefits) to consumers over their operational lifetime. Ofgem provides ongoing availability incentives in the Cap and Floor licences. This mechanism financially incentivises interconnector operators to make interconnector capacity available. For example, National Grid North Sea Link Limited's ("NSL") licence includes Availability Incentive conditions that have implications for the levels of the cap and the floor. The licence conditions reward NSL with up to a 2% increase in cap revenue if actual availability exceeds the Availability Target,[171] and penalises by decreasing cap revenue by up to 2% if it does not meet the Availability Target. Additionally, for NSL to receive payment at the floor level, actual availability must have been greater than the Minimum Availability Target ("MAT").[172] If the MAT is not met, NSL is not eligible for any floor payment. However, where an Exceptional Event has occurred, an adjustment will be applied.[173]

A1.51 Some other notable examples of Ofgem's availability incentives are described in Box A1- 2 and Box A1- 3 below.

---

171 The Availability Target for NSL is 11.4TWh based on an availability factor of 93%.

172 MAT for NSL is 9.8TWh based on an availability factor of 80%.

173 Ofgem, Guidance on the Cap and Floor conditions in National Grid North Sea Link Limited's electricity interconnector licence, 30 January 2018.

Box A1- 2: IFA

The **IFA interconnector** between GB and France was built in 1986 at a cost of GBP 700 million, which was approximately half the cost of constructing an equivalent-capacity power station. Its development was justified on the basis that it was less costly and more efficient to source energy from France than it is to transport it the length of the UK.[174]

The interconnector has since recovered its Capex. The concern was that, having recovered its Capex, IFA would have less incentive to remain available.

The GB regulator decided that when the project achieves NPV neutrality (i.e. when the upfront costs of the project have been fully recovered), positive cash flows are to be shared equally between consumers and National Grid Interconnector Limited. Ofgem considered that IFA achieved NPV neutrality on 31 March 2016, approximately 30 years after construction.[175]

Allowing some proportion of positive cash flows to be retained by IFA incentivises ongoing availability in the long term, while sharing some of the upside with consumers.

---

174 London Business School, Cross Border Electricity Trading and Market Design: The England-France Interconnector, accessed at http://faculty.london.edu/mottaviani/IFA.pdf.

175 Ofgem, IFA Use of Revenue Framework, 22 August 2016, accessed at https://www.ofgem.gov.uk/system/files/docs/2016/08/publication_of_ifa_use_of_revenues_framework_20160822.pdf.

Box A1- 3: BritNed

BritNed is an HVDC interconnector between GB and Netherlands with a 1000MW capacity. Project costs (including a rate of return) have been estimated at around GBP 500 million.[176]

For BritNed, the regulator decided to introduce an effective 'cap' on the revenues earned by the interconnector, on the basis that it sought to return any extraordinary profits to consumers.

Specifically, with respect to the allowed rate of return, for the first 10 years, if the internal rate of return is more than one percentage point higher than the initial estimated internal rate of return, BritNed must increase interconnector capacity until the initial rate of return is met, or pay additional profits equally to the transmission operators in the UK and Netherlands.[177]

The decision to impose a cap (without a corresponding floor support) has been widely seen as unsuccessful insofar as it effectively froze further investment in interconnectors in GB until the introduction of the Cap and Floor regime.

A1.52 OFTOs are also subject to performance availability incentives and obligations. OFTOs are obliged via their licence agreements to maintain at least 80% asset availability in a year and at least 85% availability over two years. They are further incentivised to achieve an availability of 98%; they are financially rewarded for exceeding this target, and penalised for falling below it.[178]

---

176 Timera Energy, Interconnectors – a competitive source of new capacity for the UK power market, 9 June 2014, accessed at https://timera-energy.com/interconnectors-a-competitive-source-of-new-capacity-for-the-uk-power-market/.

177 Ofgem, Amendment to the exemption order issued to BritNed Development Ltd under condition 12 of the electricity interconnector licence granted to BritNed in respect of the BritNed interconnector, accessed at https://www.ofgem.gov.uk/ofgem-publications/41228/britned-amended-exemption-order-pdf.

178 OFTO (December 2016) Offshore Transmission Owner Revenue Report.

B. US transmission planning

A1.53 This section summarises the key features of transmission network planning across selected jurisdictions across the US.

A1.54 The US electricity network is divided into ten "regions".[179] Seven of these "regions" consist of a single Independent System Operator ("ISO") or a single Regional Transmission Organisation ("RTO"), which are non-profit organisations with functions similar to a traditional SO. These ISOs and RTOs also take the role of system-wide planners of their respective transmission networks. An ISO or RTO can cover a single or multiple states, and are subject to regulations at the federal level (via the Federal Energy Regulatory Commission, "FERC"). Outside the footprint of these ISOs and RTOs, the use of the US transmission system in the three remaining regions continues to be scheduled by individual vertically-integrated utilities operating a control area (or balancing area).

A1.55 In the 1990s, use of the transmission lines in the US was controlled by vertically-integrated utilities. FERC found that these utilities, incentivised to exploit their information asymmetries and control of access to transmission, were discriminating against others seeking access to transmission in order to benefit their sale of generation. FERC therefore implemented Order 888,[180] which required all utilities subject to FERC jurisdiction to: (1) commit to open access non-discriminatory transmission tariffs (these were later strengthened in scope and definition by FERC Order 890 in 2007); and (2) functionally unbundle wholesale power services. Under this functional unbundling, utilities using transmission lines to sell power in wholesale markets were obliged to: (1) pay the same tariff for transmission services as other competitors; and (2) rely on the same electronic information network that its transmission customers rely on. This was intended to eliminate the information asymmetries that allowed for discriminatory access and prevent transmission owning utilities from denying competitors access to the transmission grid. FERC expanded on this with Order 889, which prevented employees of a public utility from obtaining preferential access to transmission system information.

179 These are: California; the Midwest; New England; New York; the Northwest; PJM; the Southeast; the Southwest; SPP; and Texas.

180 FERC Order 2000, Section II: Background.

A1.56 In order to comply with these orders, regions that previously operated 'tight' power pools (e.g. PJM, the New York Power Pool, and the New England Power Pool)[181] had to transition to Independent System Operators ("ISOs") that were not controlled by the transmission owning utilities. These ISOs were to "*assure both electric system reliability and competitive generation markets*".[182] ISOs would function as the SOs of a given region and as independent transmission planners. This independence was intended to prevent the exploitation of information asymmetries of incumbent utilities. While FERC Orders 888 and 889 did not explicitly require the creation of ISOs, it was the only way the existing 'tight' power pools could continue to carry out an economic dispatch while complying with Order 888. Of these, PJM was the first to be recognised by FERC as a fully functioning ISO in April 1997.

A1.57 Outside the 'tight' power pools and California there was some interest in the development of ISOs and progress was slow. Open access continued to be provided by individual control areas. The benefits from coordinated use of the transmission system in the Midwest gradually led to the western expansion of PJM into West Virginia and Ohio, and the formation of the MISO and implementation of a regional market in 2005, followed by implementation of a regional market by SPP in 2007.

A1.58 FERC followed Orders 888 and 889 with Order 2000 in 1999, which encouraged the formation of Regional Transmission Operators. In practice, these organisations serve a similar purpose to ISOs, but some commentators have argued that the expectations of RTOs are better defined than those of ISOs.[183]

A1.59 The current system-wide planning processes are largely the result of FERC Order 1000, issued in 2010. This required ISOs (and RTOs) to:[184]

- Publish regular regional transmission plans that satisfy the open access requirements in previous FERC Orders;
- Consider public policy requirements in their regional transmission plans;

---

181 A 'tight' power pool is one where a "*single, centralised dispatch distributes the lowest-cost available generation to meet demand throughout the pool*". Castalia (2009) International Experience with Cross-border Power Trading.

182 FERC Order 2000, pp 21.

183 TransMissives, Restructuring: The effects of FERC Orders 888, 889 and 2000.

184 FERC website, Order No. 1000 – Transmission Planning and Cost Allocation, accessed at: https://www.ferc.gov/industries/electric/indus-act/trans-plan.asp.

- Coordinate with other regions to plan interregional transmission assets;
- Allocate costs on a 'beneficiary pays' principle;[185] and
- Consider 3rd party solutions to address any transmission needs.[186]

A1.60 In practice, the ISOs have developed different approaches to meeting these requirements, in terms of the process of transmission planning, and the roles of the ISO's, state and market participants in those processes.

A1.61 In the US, different processes are typically used to plan different types of transmission assets. Thus (this is especially the case for NYISO), within a given region, different parties may be responsible for different stages of the transmission investment lifecycle. The different asset types are as follows:

- Reliability assets – required to resolve reliability violations (e.g. thermal, voltage, frequency, etc.);
- Economics assets – which alleviate congestion costs and/or generate market benefits (e.g. improve dispatch and reduce wholesale costs); and
- Public policy assets – required to satisfy particular public policies determined by state governments (e.g. emissions targets).

A1.62 In addition to the above, local (low-voltage) transmission is led by the TOs, which must then be introduced into the overall PJM regional planning process.

A1.63 In this section we focus on the transmission planning process in NYISO and PJM.

A1.64 Figure A1- 3 sets out an overview of the main roles and responsibilities of NYISO and PJM in relation to transmission planning, and lists some of the key outputs produced by different parties at each stage.

---

185 In practice, different ISOs have implemented this requirement in varying ways, sometimes resulting in cost allocation methodologies that have been highly criticised. See ¶A1.121 below.

186 See ¶A1.99.

Figure A1- 3: Overview of key roles and responsibilities in NYISO and PJM

Project Development Framework		1 Scenario development	2 Identify system needs	3 Identify and select solution	4 Funding the delivery
NYISO – Reliability Planning Process	ROLE	NYISO	NYISO (with inputs from TOs)	TOs and/or 3rd parties; NYISO	Selected TO and/or 3rd party developer
	OUTPUT	Reliability Needs Assessment		Project proposals; Comprehensive Reliability Plan	n/a
NYISO – Economic Planning Process	ROLE	NYISO – inputs reviewed by ESPWG	NYISO	TOs and/or 3rd parties; NYISO; Load Serving Entities (retailers)	Selected TO and/or 3rd party developer
	OUTPUT	Base case including all assets proposed in the CRP	CARIS Phase 1	Project proposals; CARIS Phase 2	n/a
NYISO – Public Policy Transmission Planning Process	ROLE	NYISO – inputs reviewed by TPAS & ESPWG	NYPSC	TOs and/or qualified 3rd parties; NYISO – additional metrics supplied by NYPSC, review undertaken by TPAS & ESPWG	Selected TO and/or 3rd party developer
	OUTPUT	Most recent base case from RPP – and assumed fully reliable system	Public Policy Requirements	Project proposals; Public Policy Transmission Plan Report	n/a
PJM	ROLE	PJM – reviewed and assisted by TEAC	PJM and individual states (public policy assets)	TOs and/or 3rd parties; PJM	Selected TO and/or 3rd party developer
	OUTPUT	Baseline Assumptions	Reliability, economic and public policy needs	Project proposals; Regional Transmission Expansion Plan (RTEP)	n/a

Regulator | SO | TO/3rd party | Generator | Load Serving Entity

Source: FTI-CL Energy analysis.

A1.65 This section additionally describes the planning process for interconnectors (referred to as interregional assets in the US) between regions. In general, interconnectors in the US are planned via agreements between neighbouring regions. The following examples of such agreements are explored in this section:

- The Northeastern ISO-RTO Planning Coordination Protocol is an agreement between ISO New England ("ISO-NE"), PJM and NYISO.[187] The agreement created several committees and set processes for determining interregional investment needs. All the above ISOs are represented in each of the committees. The Joint ISO/RTO Planning Committee ("Northeastern JIPC") performs interregional system assessments and expansion studies (elaborated on further below). The Interregional Planning Stakeholder Advisory Committee ("Northeastern IPSAC") is responsible for matters relating to stakeholder engagement. In addition to representatives from the ISOs, the Northeastern IPSAC's members also include market participants, other government agencies, regional reliability councils, and any other interested parties.
- The Joint Operating Agreement between the Midcontinent Independent System Operator and Southwest Power Pool ("MISO-SPP JOA") is an agreement between MISO and SPP similar to the Northeastern ISO/RTO agreement specified above.[188] Committees are also formed of representatives of MISO and SPP, namely the Joint Planning Committee ("MISO-SPP JPC") and the Interregional Planning Stakeholder Advisory Committee ("MISO-SPP IPSAC").

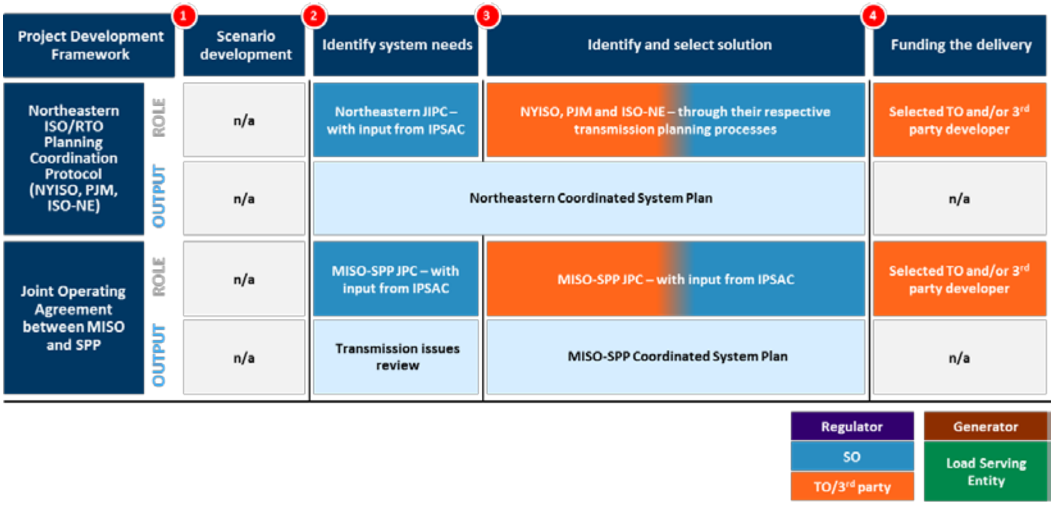
A1.66 Figure A1- 4 illustrates a similar set of roles and outputs for the various cross-regional bodies that plan US interconnector investment.

---

187 Information on the Northeastern ISO/RTO area in this subsection is obtained from the Northeastern ISO/RTO Planning Coordination Protocol.

188 Information on the MISO-SPP area in this subsection is obtained from the MISO-SPP JOA.

Figure A1- 4: Overview of key roles and responsibilities in interconnector planning for Northeastern and MISO-SPP regions

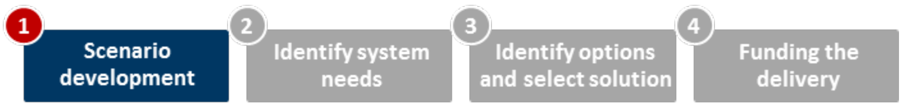


Note: There are some TOs that are part of the data sharing arrangements in the Northeastern ISO/RTO Planning Coordination Protocol, but they do not set system needs.
Source: FTI-CL analysis.

A1.67 Finally, this section also describes notable examples of transmission planning to support renewable energy zones in the US where relevant.

A1.68 The following subsections focus on each of the different transmission lifecycle stages in turn and describe the main activities undertaken by the relevant parties.

Scenario development



A1.69 In the US, scenario development is conducted as an intrinsic part of the main transmission planning process. This contrasts with the GB approach, where forecasting future scenarios is an exercise run independently of transmission planning. As such, scenario development in PJM and NYISO occurs with the same frequency as the overall transmission planning process for that region.

A1.70 In the **NYISO area**,[189] the ISO develops and publishes the NYISO Gold Book, which contains baseline forecasts of NYISO load and capacity data for the next ten years.[190] The forecasts in the NYISO Gold Book are the result of a two-stage process. In the first stage, NYISO performs econometric forecasts that take into account historical data and economic growth. In the second stage, these econometric forecasts are explicitly adjusted to reflect exogenous factors such as: energy efficiency programs and standards; building codes; distributed energy resources; and behind-the-meter solar PV generation. These adjustments are based on information received from a variety of New York state authorities.[191] Subsequent adjustments may be made to these baseline forecasts for the purposes of its biennial (once every two years) transmission planning process. Data shared with NYISO as per the Northeastern ISO-RTO Planning Coordination Protocol between NYISO, PJM and ISO-NE is also taken into account.[192] These adjusted forecasts (henceforth referred to as the "NYISO reliability base case") are used to determine NYISO's reliability needs.

A1.71 After reliability needs are identified, and preferred solutions selected (see ¶A1.101 below), the NYISO reliability base case is updated to reflect the chosen solutions. This updated base case forms the basis for the identification of economic needs. The identification of reliability and economic needs is therefore undertaken in a sequential manner to ensure mutual consistency.

A1.72 For public policy assets, the NYPSC is not obliged to use any particular sources of information for the development of scenarios to identify public policy needs.

---

189 Information on NYISO in this subsection is obtained from the following sources: NYISO Reliability Planning Process Manual; NYISO Economic Planning Process Manual – Congestion Assessment and Resource Integration Studies (CARIS); NYISO Public Policy Transmission Planning Process Manual.

190 The Gold Book takes into account the fact that purely merchant transmission may be built, as well as those planned through the system-wide planning process described in this report.

191 These include the New York State Department of Public Service ("NYDPS"), the New York State Energy Research and Development Authority ("NYSERDA"), power authorities, electric utilities and TOs. Source: NYISO (2017) Gold Book.

192 This is the agreement between NYISO, PJM and ISO-NE for the purposes of interregional transmission planning. See ¶A1.85 below for further details.

A1.73 In the **PJM area**,[193] the ISO develops a base case for use in assessing reliability needs. This is a 15 year forecast of load levels, base power flows, and other metrics necessary to assess compliance with reliability standards. In addition, the ISO develops a five year near-term reliability analysis. The assumptions that feed into both forecasts are vetted with stakeholder committees before the final outputs are reviewed and approved by the PJM Board. These stakeholder committees collectively form the Transmission Expansion Advisory Committee.[194] These reliability analyses are used to determine reliability needs.

A1.74 To assess economic assets, PJM uses the same base case that was used to identify reliability needs, updated to reflect the latest available information. As with NYISO, the identification of reliability and economic needs is performed sequentially.

A1.75 In general, no explicit scenario analysis is required to test the sensitivity of PJM's base case. However, if it considers it necessary, PJM will explore several different scenarios for the purposes of its transmission planning. For example, in 2015, three different scenarios examined adjustments to the baseline forecasts in the form of higher winter load, the retirement of specific plants, and an environmental policy requirement.

A1.76 In this sense, the use of PJM's scenarios is 'mandatory'. Additionally, scenario development is usually limited to a base case, and in the case of PJM, some 'alternative scenarios' if necessary.

A1.77 For both NYISO and PJM, proposed solutions are usually expressed by developers simply in technical terms. The cost benefit analysis is developed by the SOs or by developers themselves – for example in order to initiate the discussion of a particular project.[195] While third party analyses may not be relied on for the purposes of cost allocation, they can form part of the solution discussion.

---

193 Information on PJM is this subsection is obtained from the following sources: PJM Manual 14B; PJM (2015) RTEP Book 2.

194 Membership is open to *"(i) all Transmission Customers…; (ii) any other entity proposing to provide Transmission Facilities…; (iii) all Members; (iv) the agencies and offices of consumer advocates of the States in the PJM Region;…and (v) any other interested entities or persons"*. Source: PJM – TEAC Charter.

195 FTI-CL has supported parties in developing cost-benefit analysis in PJM.

A1.78 The planning process for interconnectors does not typically feature its own scenario development. For interconnectors in the Northeastern Region, and between MISO and SPP, the planning committees tend to rely on information shared between the ISOs responsible for the respective regions, rather than run their own scenario development.

A1.79 In general, when scenario development is based on a large number of parameters that are directly under the ISO's control, there is a risk that it may not be seen to be independent. The ISO may be perceived by some to:

- have an inappropriate influence over the outcome of the subsequent investment test;
- have an inappropriate influence over the cost allocation; and
- create political controversy.

A1.80 To address the perception of this risk, ISOs typically tend to have functional, legal and economic independence. In addition, the SOs seek to undertake their activities with sufficient transparency and rely on a consultative approach that takes into account feedback from a wide range of market participants. These activities lend greater perceived credibility to the SOs' activities and scenarios. ISO decisions are also subject to FERC review.

Identify system needs

A1.81 In the **NYISO area**,[196] both reliability and economic needs are identified by the SO, based on the base case forecasts discussed above (see ¶A1.70), while public policy needs are determined by the NYPSC. Reliability needs are communicated to the market via the Reliability Needs Assessment ("RNA") report. Specific sites and corresponding violations of reliability criteria are identified as 'needs to be resolved'. Economic needs are communicated via the CARIS Phase 1 report. These are expressed in the form of projected congestion costs for the most congested geographic areas over ten years and projected benefit-cost ratios for generic solutions for each of those areas. Public policy needs are expressed in the form of written statements from the NYPSC that are posted on the NYISO website.[197]

A1.82 In the **PJM area**,[198] reliability needs are also identified by the ISO and based on the forecasts discussed above (see ¶A1.73). Similar to NYISO, expected reliability violations for specific sites will be posted on PJM's webpage in the form of Problem Statements. Economic needs are identified using the updated base case forecasts discussed above (see ¶A1.74) and by assessing if any of the selected reliability solutions could be accelerated or modified to also meet economic needs. These needs are also posted on PJM's webpage and expressed in the form of expected congestion costs five years and eight years in the future. Public policy needs are determined via the State Agreement Approach. Entities authorised by their respective states (regulators, stakeholder groups, etc.), individually or jointly, propose such needs.

---

196 Information on NYISO in this subsection is obtained from the following sources: NYISO Reliability Planning Process Manual; NYISO Economic Planning Process Manual – Congestion Assessment and Resource Integration Studies (CARIS); NYISO Public Policy Transmission Planning Process Manual.

197 As per FERC Order 1000, public policy needs are not a 'mandate' to build a transmission asset, rather they are a different type of need that should be considered by ISOs. Exactly how those needs are considered by a given ISO will vary on a case by case basis.

198 Information on PJM is this subsection is obtained from the following sources: PJM Manual 14B; PJM (2016-2017) Problem Statement.

A1.83 In general, third parties themselves do not have a formal role in specifying asset needs, and must wait for the relevant authorities (SOs or state regulators) to specify them. However, they can proactively put forward specific projects (as solutions to 'needs' identified by the developers) in order to obtain regulators' and stakeholders' buy-in to the proposal. In addition, even if developers do not proactively suggest their own projects, transmission planning in the US happens with predictable regularity, so developers face limited risk of 'missing out'.

Interregional assets

A1.84 As mentioned earlier in this report, FERC Order 1000 requires neighbouring ISOs to co-operate in planning interconnector (known in the US as "interregional") investments. As such there are various agreements in place between neighbouring ISOs that address cross-regional needs. This report explores two such agreements below:

The Northeastern ISO-RTO Planning Coordination Protocol

A1.85 On an annual basis (or at the request of any of the three ISOs), the Northeastern Joint ISO/RTO Planning Committee ("JIPC") will review the regional needs and solutions identified in individual regions' planning processes. This includes all reliability, economic and public policy needs/solutions. They will aim to identify needs that could be met by interregional assets. In practice, this requires the sharing of data between the ISOs; this is mandatory as per FERC 1000. Ontario's Independent Electricity System Operator ("IESO"), Hydro-Quebec and New Brunswick Power have also agreed to voluntarily participate in this data sharing. The Northeastern Interregional Planning Stakeholder Advisory Committee ("IPSAC") will also provide input where necessary.

A1.86 Upon identifying needs in individual regions that could be met by interregional assets, the Northeastern JIPC will propose them in accordance with the respective regions' planning processes. These proposals will then be subject to the relevant evaluations in the respective regions.

A1.87 The Northeastern JIPC will also aim to identify proposed solutions in the individual regions' transmission plans that would be more efficient or cost effective if replaced by an interregional asset. If this can be proven, *"the corresponding existing regional transmission projects shall be displaced".*[199]

A1.88 The needs identified and assets proposed in this manner will be communicated via the Northeastern Coordinated System Plan ("NCSP"). This document is drafted by the Northeastern JIPC, with input from the Northeastern IPSAC.

---

[199] Northeastern ISO/RTO Planning Coordination Protocol, 10 July 2013.

Joint Operating Agreement between MISO and SPP

A1.89 The MISO-SPP JPC runs an annual Transmission Issues review, which evaluates if any transmission needs have arisen for reliability, economic and/or public policy reasons that could be addressed with an interregional asset. The MISO-SPP IPSAC provides input into this process where relevant. Unlike the Northeastern JIPC process, the Transmission Issues review is not integrated with the individual planning processes of MISO and SPP.

Renewable zones

A1.90 Transmission investment to connect renewable zones has sometimes been approached differently from the standard transmission investment processes. Below we discuss how transmission needs were determined for renewable zones in two regions – ERCOT and MISO.

ERCOT, Texas – Competitive Renewable Energy Zones

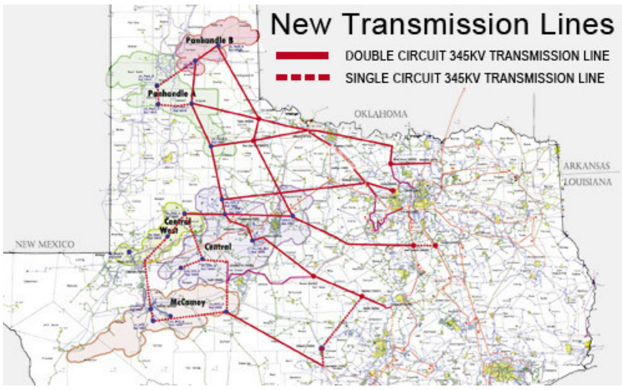
A1.91 By 2004, the Texas government recognised that a ‘chicken and egg’ problem had developed between wind development and transmission. TOs were unwilling to commit to investing in transmission lines without a commensurate commitment from wind developers to build new generation assets. Wind developers were similarly unwilling to commit to building new plants given the long lead time required to construct transmission lines. In response to this, the Public Utilities Commission of Texas (PUCT), the regulator, and the Electric Reliability Council of Texas (ERCOT), the ISO, began to develop Competitive Renewable Energy Zones (CREZ) and a transmission plan to deliver the power generated from CREZ sites to customers. Based on desktop studies, input from wind developers, and financial commitment from wind developers, the PUCT identified five zones in 2007 and began to develop an optimal transmission route.[200]

A1.92 These proposed transmission lines were in the form of new ‘backbone’ transmission lines, as opposed to extending existing lines, as illustrated in Figure A1- 5 below.

---

[200] Clean Energy Grid (October 2017) Texas as a National Model for Bringing Clean Energy to the Grid, accessed at https://cleanenergygrid.org/texas-national-model-bringing-clean-energy-grid/.

Figure A1- 5: Map of CREZ transmission lines



Source: Texas State Energy Conservation Office.

A1.93 Financial commitment by generation developers to a given zone was measured by the amount of existing or planned renewable generation, and the amount of capacity represented by signed interconnection agreements. Alternatively, wind developers could declare their financial commitment to a given zone by posting deposits of between USD 10,000 to USD 15,000 per MW.[201]

A1.94 This was an example of proactive transmission investment, whereby renewable zones were sited and transmission lines committed before any physical generation plants were built. A defining feature of this approach was the requirement for the developers to commit to the new generation build, which mitigated the risk of stranded transmission assets. Importantly, the transmission investment projects as well as the renewable zones were located entirely within Texas, which meant that the cost allocation was within-state (and avoided the more complex process of allocating costs and benefits between states).

A1.95 As of 2017, Texas had surpassed its original target of 18GW of wind capacity, and was on track to build 70% more than originally planned. The transmission lines have incurred construction costs of approximately USD 7 billion.[202]

---

[201] PUCT (2009) Project No 34577 – Order, accessed at https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.174/34577adt.pdf.

[202] Clean Energy Grid (October 2017) Texas as a National Model for Bringing Clean Energy to the Grid, accessed at https://cleanenergygrid.org/texas-national-model-bringing-clean-energy-grid/.

A1.96 This approach has been effective in delivering the stated public policy goal of developing new wind generation (and connecting it to the rest of the power grid). However, the primary purpose of policy makers was to deliver renewable energy in a cost-effective manner, in order to meet a particular policy goal. Some cost-benefit analysis of transmission paths (and specific renewable zones) was undertaken, for example by ERCOT.[203] However, this was not a holistic generation-cum-transmission optimisation process, but rather a cost-benefit analysis targeting a particular environmental policy goal. In this sense, this approach demonstrates the 'effectiveness' (but not necessarily 'efficiency') of the cost socialisation approach in ERCOT.

---

[203] In 2006 ERCOT performed a study that did explore the potential costs of alternative transmission options to service the CREZs. However, ERCOT acknowledged that this CBA was limited: "*This study was designed to provide cost and benefit comparisons of a large number of different alternatives. As a result, it was not possible…to fully characterize the system benefits associated with these improvements*". ERCOT (2006) Analysis of Transmission Alternatives, Section VI, Sub-sections E and F.
Subsequently, in 2008, ERCOT performed a more detailed study that examined 5 alternative transmission plans and weighed their costs against the fuel cost savings and total amount of wind generation that could be supported. ERCOT (2008) CREZ Transmission Optimisation Study.

MISO – Regional Generation Outlet Study

A1.97 The MISO RGOS developed plans for renewable energy zones by coordinating renewables targets between its member states.[204] The RGOS intended to design a transmission plan that would enable individual MISO states to build a sufficient volume of new renewables generation in order to meet their RPS at the lowest wholesale cost to the region.[205] In particular, the RGOS study proposed different permutations of locations for renewable generation (and subsequently the transmission required to facilitate that renewable generation) and focused on different options to deliver around 25GW of wind and other renewables.[206] This approach would help mitigate the risk that renewable developers may construct new assets in an uncoordinated (and potentially inefficient) manner, and that transmission investment would therefore need to 'follow' such inefficient investment, compounding the overall cost to consumers. RGOS considered it appropriate to assess the new build projects as a portfolio, rather than making investment decisions in respect of each asset individually. This was referred to as 'multi value project portfolio'.

A1.98 The analysis showed that a combination of local renewable new build (meeting RPS with resources located within the same state as the load) and regional renewable new build (meeting RPS with resources located in renewable energy zones with high resource availability) was deemed to be the most cost effective.[207] This is illustrated in Figure A1- 6 below. The plan has widely been considered a success, and has delivered benefits above initial expectations.[208]

---

204 The MISO area covers 15 states in the Midwest and the South of the US, extending from Michigan and Indiana to Montana, and from the Canadian border to Louisiana and Mississippi.

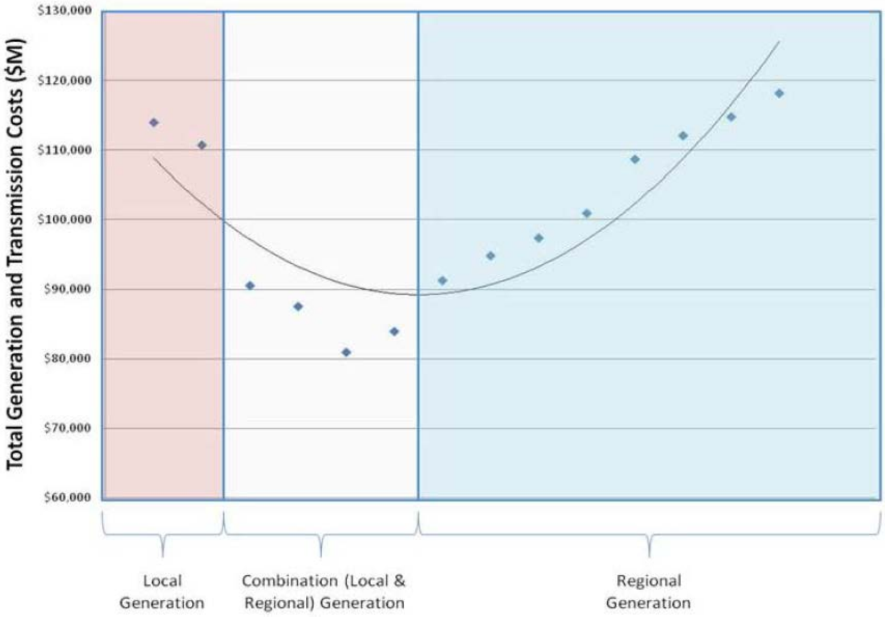
205 The challenge was to balance lower transmission investment to deliver wind from low availability areas (typically closer to load centres), against higher transmission investment to deliver wind from higher availability areas (typically further from load centres). Source: MISO (2012) Multi Value Project Portfolio.

206 MISO (2010) Regional Generation Outlet Study, Section 3.1.

207 Ibid.

208 Energy Collective (2017) MISO's Triennial Review of Regional Transmission Lines; MISO (2017) Multi Value Project Triennial Review Report.

Figure A1- 6: MISO RGOS generation and transmission cost comparison



Source: MISO (2010) Regional Generation Outlet Study, Fig 5.1-1.

Identify options and select solution

A1.99 Investment tests in the US typically consider the impact on consumers, producers, and congestion rents. FERC Order 1000 prohibits incumbent TOs from having any Right of First Refusal on transmission investment (this relates to the incumbent TO previously having the right to build and operate the transmission asset). As a result, non-TO parties must be (and are) allowed to submit proposed solutions to identified needs, as well as to build and operate such assets.[209] ISOs can also identify and propose their own solutions.[210]

A1.100 A detailed analysis of investment tests undertaken by the US jurisdictions can be found in a separate FTI-CL Energy report from September 2018.[211] This section summarises the most salient features.

A1.101 In the **NYISO area**,[212] TOs and 3rd parties must state the need specified by NYISO that they intend to address when proposing a solution. NYISO effectively runs three separate investment tests, one for each type of need. The same discount rate is used to assess all assets – a weighted average of the costs of capital of all the incumbent TOs in the NYISO region.[213] The individual test methodologies are briefly summarised as follows:

- ***Reliability need***: NYISO evaluates the technical viability and the cost-efficiency of market based and regulated solutions over a ten year horizon, which include generation, transmission and demand-response solutions.

---

209 FERC Order 1000.

210 The decision on the preferred solution to be implemented can be made by ISO stakeholder vote (e.g. in PJM), but this can also be made by state appointed regulators and committees (this is the case for example in ERCOT and CA).

211 See FN16.

212 Information on NYISO in this subsection is obtained from: Information on NYISO in this subsection is obtained from the following sources: NYISO Reliability Planning Process Manual; NYISO Economic Planning Process Manual; NYISO Public Policy Transmission Planning Process Manual; NYISO (2015) CARIS Phase 1 Report; NYISO (2017) CARIS Phase 1 Report; NYISO Open Access Transmission Tariff – Attachment Y.

213 This was 7.0% in 2017 and 6.8% in 2015.

- ***Economic need***: NYISO assesses the type of solution (generation, transmission or demand-response) most likely to produce the greatest net benefit. They then request and evaluate proposals for specific solutions over a 10-year horizon. NYISO checks that benefits are likely to be greater than costs. It then calculates the expected benefits to LSEs, and for each given proposed solution, assigns voting weights to each LSE equal to the proportion of project benefits it is likely to receive. Projects that receive a supermajority of 80% or over of LSE votes will be approved and can receive regulated cost recovery through tariffs.
- ***Public policy need***: The NYPSC identifies a need and NYISO requests and evaluates all potential solutions. If a transmission solution is required, NYISO evaluates the proposed solution and identifies the most cost-efficient solution. This evaluation is reviewed by stakeholders and the NYISO Board may select a solution.

A1.102 Disputes can be raised by any party participating in the NYISO planning process. Participants will first attempt to resolve disputes internally without raising formal complaints. If this is not successful, the dispute will be referred to the NYPSC for resolution. The NYPSC's judgements will be binding, subject only to judicial reviews by courts of law. There are no set time limits by which disputes must be resolved informally before they are automatically referred to the NYPSC. For public policy assets, where disputes may be raised against the NYPSC, if the matter cannot be resolved informally it will be subject to judicial reviews by courts of law.

A1.103 In the **PJM** area,[214] TOs and 3rd parties must state the need specified by PJM they intend to address when proposing a solution. PJM effectively runs two separate investment tests, one for each type of need, but they may be interrelated in that a reliability asset can be considered an economic asset if it meets certain criteria. The same discount rate is used to assess all assets – a weighted average of the costs of capital of all the incumbent TOs in the PJM region.[215] The individual test methodologies are briefly summarised as follows:

- ***Reliability need***: PJM first evaluates if the proposed solution meets the identified need, and then evaluates the cost. The cost is the present value of the revenue requirement of the enhancement for the first 15 years of the asset's life. PJM then assesses if any of the proposed solutions meet the criteria for an economic asset if they are enhanced or expanded.
- ***Economic need***: asset is constructed if its benefit-cost ratio is above 1.25. As with reliability assets, the cost is the present value of the revenue requirement for the first 15 years of the asset's life. The benefits are the changes in costs of: fuel, operation and maintenance, and emissions of the dispatched resources in the PJM region if the asset is built. They also include expected effects on congestion, load and LMPs in each zone, expected effects on PJM's capacity market, and price effects on energy bought from and sold to regions outside PJM.

[214] Information on PJM in this subsection is obtained from the following sources: PJM Manual 14B; PJM Operating Agreement – Schedule 6.

[215] This was 7.4% in 2017 and 2016, and 7.8% in 2015.

- ***Public policy need***: these needs are assessed via the State Agreement Approach. This is a separate process from PJM's cost benefit assessment discussed above. Entities authorised by their respective states, individually or jointly, may agree voluntarily to be responsible for all allocation of costs of a proposed transmission investment that addresses some public policy requirement.[216] These assets are included in the PJM RTEP, and not assessed by PJM directly. This contrasts with the NYISO approach, in which a state body proposes a public policy need, but NYISO runs the investment test and ultimately decides on the preferred solution.

A1.104 The output of PJM's transmission planning, the PJM Regional Transmission Expansion Plan ("PJM RTEP") [217] is reviewed by PJM's Board of Managers, who have the final authority for its approval and implementation.

A1.105 Similar to NYISO, any party involved in the PJM transmission planning process can raise a dispute. The parties in dispute will first undertake good-faith negotiations to resolve the matter. If such negotiations are not successful in resolving the dispute, an independent (professional) mediator will be selected. If necessary, a second mediator with technical experience (rather than professional mediation experience) will be appointed as well. The mediator(s) will attempt to facilitate negotiations between the parties to resolve the dispute. If within 30 days the parties do not themselves agree on a resolution, the mediator will communicate a recommended, non-binding solution. The cost of the mediator(s) will be borne equally by all parties in the dispute. If the mediator is unable to resolve the dispute, the parties will enter arbitration procedures, which are legally binding. The arbitrator's decision will be filed with FERC.

---

216 Like assets to address public policy needs in the NYISO region, a public policy need does not 'mandate' a transmission asset to be built. Public policy assets must still be approved via the State Agreement Approach.

217 PJM will recommend for inclusion in the RTEP those transmission upgrades (or acceleration of previously planned upgrades) that ensure Auction Revenue Rights ("ARRs") will be maintained (according to base load forecasts) at least 10 years into the future. ARRs are entitlements allocated annually to firm transmission service customers that entitle the holder to receive an allocation of the revenues from PJM's Annual FTR Auction. This is a potential driver of 'investment need' considered in PJM. Source: PJM Manual 06 (version dated 1 June 2018), pp 22.

Interregional assets

A1.106 As discussed previously, interconnectors in the **PJM, NYISO and ISO-NE** area are planned for via joint co-operation between the SOs[218] and can be proposed as new assets via the transmission planning processes of the individual regions. Interconnectors can also displace existing regional preferred solutions if they can be proven to be more efficient or cost-effective. This is also assessed via the individual planning processes of NYISO, PJM and ISO-NE. In effect, this means that any given interconnector has to pass the investment tests of two jurisdictions before it is built.[219]

A1.107 In the event of any disputes between the parties of this agreement, the CEOs (or other sufficiently senior members of staff) of the ISOs should first try to resolve the dispute informally. If this is not completed within ten days, the issue could be referred to a neutral, third-party Dispute Resolution Service (arbitration) – this may include FERC's Dispute Resolution Service. Costs for dispute resolution are borne equally between parties in dispute.

---

218 Information on the Northeastern ISO/RTO area in this subsection is obtained from the Northeastern ISO/RTO Planning Coordination Protocol.

219 In practice, recent interregional transmission investment in the Northeast ISO/RTO area have been merchant investments, and therefore have not subject to this investment test.

A1.108 As per the **MISO-SPP JOA**,[220] if determined to be necessary by the annual Transmission Issues review, a Coordinated System Plan study will be undertaken by the MISO-SPP JPC, where each ISO and any 3rd parties may propose interregional solutions for evaluation. The impact on systems in other transmission planning regions will also be considered. The Coordinated System Plan outlines issues evaluated, studies performed, solutions considered, and recommended projects with interregional cost allocation (if applicable). This is reviewed by IPSAC, who will provide feedback and recommend a project based on a vote.[221] The JPC will then vote on whether to recommend the project and suggested cost allocation to each region's individual process for approval.[222] Projects should have an estimated cost exceeding USD 5 million, and the benefit to MISO and SPP individually must be 5% or more of the total interregional benefits. Approval by both parties is required.

A1.109 The MISO-SPP IPSAC plays a more active role than the Northeastern IPSAC. Also, unlike the Northeastern process, there is no provision for an interregional asset to displace a proposed intra-regional asset.

A1.110 As with the Northeastern ISO/RTO agreement, any parties to the MISO-SPP JOA that are in dispute should first attempt to resolve the matter through negotiations in good faith. If this is unsuccessful, the dispute will be referred to the FERC for mediation. If mediation is unsuccessful, the matter may then be referred formally to FERC for dispute resolution.

Funding the delivery of the asset

A1.111 In general, the party who proposed the selected solution is responsible for designing and delivering it. This is consistent across the asset types identified above. However, cost allocation methodologies differ by jurisdiction and asset type, though it is consumers that bear the risks through transmission charges paid via their electricity bills.

---

220 Information on the MISO-SPP area in this subsection is obtained from the MISO-SPP JOA.

221 The IPSAC Voting Process outlined in the MISO-SPP JOA stipulates that each Party's (individually, SPP and Midwest ISO) defined voting group represents one vote.

222 The JPC Voting Process outlined in the MISO-SPP JOA stipulates that each Party is permitted to cast one vote, even though the JPC may have multiple representatives from each Party.

A1.112 Issued in 2011, FERC Order 1000 requires jurisdictions to adopt a beneficiary-pays principle for regulated assets. However, the application of this principle can be difficult. In practice, the allocation of costs between zones or parties varies across jurisdictions and asset types, and includes a combination of measures based on ex-post flows, simple cost socialisation, changes in load energy payments, and any other methodology proposed by parties that FERC considers reasonable.

A1.113 **NYISO**'s cost allocation methodology depends on the asset type:[223]

- ***Reliability assets***: NYISO considers that the primary beneficiaries are those load zones contributing to the reliability violation. Thus, the cost allocation is based on their relative contributions to the given reliability violation. There are specific formulae for different reliability asset types (i.e. different cost allocation formulae for assets resolving resource adequacy, thermal transmission security, voltage security, and so on). This contrasts with the PJM approach, which uses a method reliant on ex-post flows and voltage for all assets.

- ***Economic assets***: NYISO allocates costs to zones based on share of total load savings, and then within zones to benefiting load serving entities based on their share of the savings. This is identical to the process by which voting weights are assigned to the LSEs for approving the project. NYISO aims to ensure that the beneficiaries who have the most to gain from a given investment have both: (1) the most influence over deciding whether or not it should be built and (2) the greatest responsibility for proportion of the costs of the asset. This is similar to the Argentinian approach.

- ***Public policy assets***: the public policy need set by NYPSC would usually prescribe a particular cost allocation methodology. The TO or 3rd party developer proposing the preferred solution may also propose an alternative cost allocation methodology (which would require pre-approval by FERC). If neither the NYPSC nor the developer proposes a cost allocation methodology, the following default applies: 25% to all zones based on load share (socialised) and 75% to zones that economically benefit from the project according to their relative reduction in energy payments.

---

223 Information on NYISO in this subsection is obtained from the following sources: NYISO Tariff, Section 31.5; NYISO Tariff – Attachment Y.

A1.114 In the **NYISO** region, after preferred solutions have been selected, but before construction has been completed and the assets fully delivered, the ISO monitors the progress of the preferred solutions closely. Transmission projects are often planned far in advance, therefore NYISO regularly updates forecasts to monitor the continued need for the asset:

- ***Reliability assets***: After a preferred solution is selected, NYISO will monitor the project by continuously reviewing the asset's viability and progress. Information is required to be submitted at least every quarter, and NYISO reserves the right to cancel a solution part-way and replace it with another if necessary.
- ***Economic assets:*** While there are no specific NYISO monitoring provisions for economic assets, developers would have included in their solutions proposals for dealing with potential cost overruns.
- ***Public policy assets:*** NYISO's monitoring process for these assets is similar to that for reliability assets. The documentation is unclear on the steps NYISO may take in cases where a proposed solution fails to adhere to its proposed schedule or is no longer the most efficient or cost effective solution.

A1.115 **PJM**'s cost allocation depends both on asset type and on voltage.[224] The cost allocation used in each case is generally some combination of two methodologies: the Distribution Factor Analysis ("DFAX"); and load share. The cost allocation for public policy assets is determined by the State Agreement Approach.

A1.116 The DFAX methodology identifies the share of the costs that a zone should be responsible for based on the benefit they derive, as measured by the power that would flow over the transmission facility after its construction. In comparison, the load share methodology allocates costs across energy zones according to each zone's non-coincident peak load.[225] Costs that are below USD 5 million or are clearly limited to a single price zone are immediately allocated to that zone. Under the State Agreement Approach, entities authorised by their respective states, individually or jointly, agree voluntarily to be responsible for all allocation of costs of a proposed transmission investment.

---

[224] Information on PJM in this subsection is obtained from the following sources: PJM Manual 14B; PJM (2016) Cost Allocation – presentation by Vilna Gaston.

[225] Non-coincident peak load is a customer's maximum energy demand across an entire time period. This contrasts with coincident peak load, which measures maximum energy demand during periods of peak system demand.

A1.117 The cost allocation methodologies for PJM transmission assets are detailed in Table A1- 1 below.

Table A1- 1: Method of cost allocation DFAX and load share

Asset need (Voltage)	Reliability assets	Economic assets	Public policy assets
Low (<345kV)	100% using DFAX	100% allocated to zone with NPV benefits[226]	State Agreement Approach
High (>=345kV)	50% using DFAX; 50% using load share	50% load share; 50% allocated to zone with NPV benefits	State Agreement Approach

Source: PJM (2016) Cost allocation presentation.

A1.118 PJM can also combine separate solutions, or enhance a given solution to address a combination of reliability, economic and/or public policy needs. The project will, as much as possible, be separated into reliability, economic and/or public policy needs, and costs allocated according to the respective methodologies.

A1.119 There are several criticisms of the PJM cost allocation approach. In general these are related to the reliance on:

- ex-post flows via the DFAX methodology; and
- voltage levels of the asset need.

A1.120 The allocation using ex-post flows in the DFAX methodology is often considered to be imperfect. The DFAX methodology is not based on changes in flows resulting from the investment. In addition, the flows associated with a particular party's transactions over the new transmission lines depend on the characteristics of the line in question, and not on who benefits. Yet, despite its imperfections, PJM continues to use this methodology (partly because it was the result of many years of debate and compromise).

A1.121 There have been several notable examples of strong disagreements with the DFAX methodology.

226 This is when there is a decrease in the net present value of pro rata load energy payments, which is:

(Sum of hourly zonal loads x hourly locational marginal pricing) – (value of financial transmission rights).

- In 2014, Con Edison argued that the costs that had been allocated to them for the Bergen-Linden line using the DFAX methodology did not take into account the benefits of fixing short-circuit violations, and that PJM did not apply a *"reasonable engineering judgement"* to determine if DFAX produced *"objectively reasonable results"*. Con Edison considered that the methodology allocated costs that were not roughly commensurate with the benefits received and argued therefore that they were allocated an inappropriately high proportion of costs.[227,228] After losing a challenge filed with FERC, Con Edison terminated the agreement that created the flows so the costs would no longer be allocated to Con Edison.[229]
- Linden VFT found out, based on Con Edison's submission (see point above) that it would also face significant costs for the Bergen-Linden line. Linden VFT considered that it was allocated inappropriately high costs, and also challenged the cost allocation rules in 2014. Linden claimed that *"PJM has chosen to apply the rules applicable to double circuit 345kV transmission lines versus those for circuit breakers that would more appropriately reflect what is happening. As a result…the PSE&G zone would avoid almost 94% of the portion of the project cost that is allocated using DFAX"*.[230]

A1.122 Moreover, the dependence of the cost allocation methodology employed on the technical attributes of the transmission upgrades (e.g. voltage levels) mean that the choice of technology can swing large proportions of costs to be allocated via one methodology or another. For reliability assets, this incentivises local TOs to find a way to address the reliability need using a higher voltage line, so that some of the costs can be allocated outside of their zone.

---

227 Which, Con Edison argued, as the main purpose of the Bergen-Linden line in the first place.

228 Transmission Hub (November 2014) PJM cost allocation for PSE&G projects overcharges Con Edison by USD 650m.

229 In May 2016, Con Edison announced that they would not renew its contract with PSE&G after its expiration in April 2017 as *"unfair cost allocations have become too costly for our customers"*. Source: RTO Insider (May 2016) Con Ed-PSEG 'Wheel' Ending Next Spring, accessed at: https://www.rtoinsider.com/con-ed-pseg-wheel-pjm-ending-26295/.

230 RTO Insider (March 2014) PJM: Con Ed Protest over PSEG Upgrade Groundless, accessed at: https://www.rtoinsider.com/pjm-con-ed-pseg-protest/.

A1.123 After selecting a preferred solution, PJM will also monitor the construction of the asset closely to ensure it meets its specified milestones. PJM has the power to cancel or pause the construction of solutions if costs overrun too far above initial estimates or if milestones are not met. PJM has exercised this power in the past; it temporarily halted the Artificial Island project in August 2016 over cost concerns.

A1.124 Additionally, while transmission investments are assessed in the US over a period of time that is shorter than the typical useful life of a transmission asset, their costs are typically recovered over their full useful life. Moreover, as transmission planning in the US occurs on a regular basis, any planned transmission investments are constantly re-evaluated.

Interregional assets

A1.125 Cost allocation mechanisms for interconnectors (interregional assets) in the US may differ from the corresponding regions' intra-regional assets.[231]

A1.126 For interconnectors subject to the Northeastern ISO-RTO Planning Coordination Protocol, cost allocation is subject to methodologies agreed separately between the neighbouring states. For example, for a given interregional asset connecting NYISO and PJM, costs are allocated to each region based on the ratio of the present value of the costs of the displaced regional projects.[232] The NYISO-PJM JOA, ¶ 35.10.2(b) states:

> *"The share of the costs of an Interregional Transmission Project allocated to a Region will be determined by the ratio of the present value of the estimated costs of such Region's displaced regional transmission project or projects to the total of the present values of the estimated costs of the displaced regional transmission projects in the Regions that have selected the Interregional Transmission Project in their regional transmission plans."*

6.30 The NYISO-PJM JOA ¶ 35.10.2(h) further states:

---

231 The information on US interconnectors in this subsection has been obtained from the following sources: MISO-SPP JOA; Northeastern ISO/RTO Planning Coordination Protocol.

232 Both SOs and any relevant TOs and other stakeholders must agree on a single discount rate and base year for the purposes of calculating this present value.

"When a portion of an Interregional Transmission Project evaluated under the Protocol is included by a region (Region 1) in its regional transmission plan but there is no regional need or displaced regional transmission project in Region 1 and the neighbouring region (Region 2) has a regional need or displaced regional project for the Interregional Transmission Project and selects the Interregional Transmission Project in its regional transmission plan, all of the costs of the Interregional Transmission Project shall be allocated to Region 2 in accordance with the methodology in this Section 35.10.2 and none of the costs shall be allocated to Region 1."

A1.127 The documentation is however unclear on the cost allocation between regions if Region 1 has no displaced regional asset, but also benefits from the proposed interregional asset.

A1.128 For interregional assets proposed under the MISO-SPP JOA, costs are allocated between regions (and then to zones using each region's respective cost allocation methodologies) in proportion to the benefits accruing to each region. These benefits are calculated differently depending on whether the interregional asset addresses a reliability, economic or public policy need.

Box A1- 4: MISO-PJM Multi-Value Project Cost Allocation[233]

In 2010, MISO proposed a new cost allocation category for projects identified as Multi-Value Projects ("MVPs") that address reliability or economic issues affecting multiple transmission regions. This allocation assigned no costs to PJM, even though the MVPs would reduce the costs of imports into PJM, benefiting those customers. This was to comply with FERC's ban on inefficient rate pancaking.[234] There was therefore a conflict between the objectives of: (1) allocating costs to beneficiaries; and (2) avoiding transmission rate pancaking.

After much debate, in 2016 FERC found it appropriate to allow transmission rate pancaking on MISO exports to PJM through MVP lines, in favour of ensuring beneficiaries paid for the cost of the transmission investment.

233 Washington Energy (July 2016) FERC Lifts Restriction on MISO Export Pricing to PJM for Multi-Value Projects.

234 "*Rate pancaking occurs when a transmission customer is forced to pay separate rates for a transaction that crosses multiple transmission systems. While some forms of rate pancaking reflect efficient charges for the capital costs of the transmission network, pancaking can be inefficient if it results in total transmission prices that do not accurately reflect the actual cost associated with a particular transaction*", Eastern Interconnection States' Planning Council (February 2015) Electric Transmission Seams.

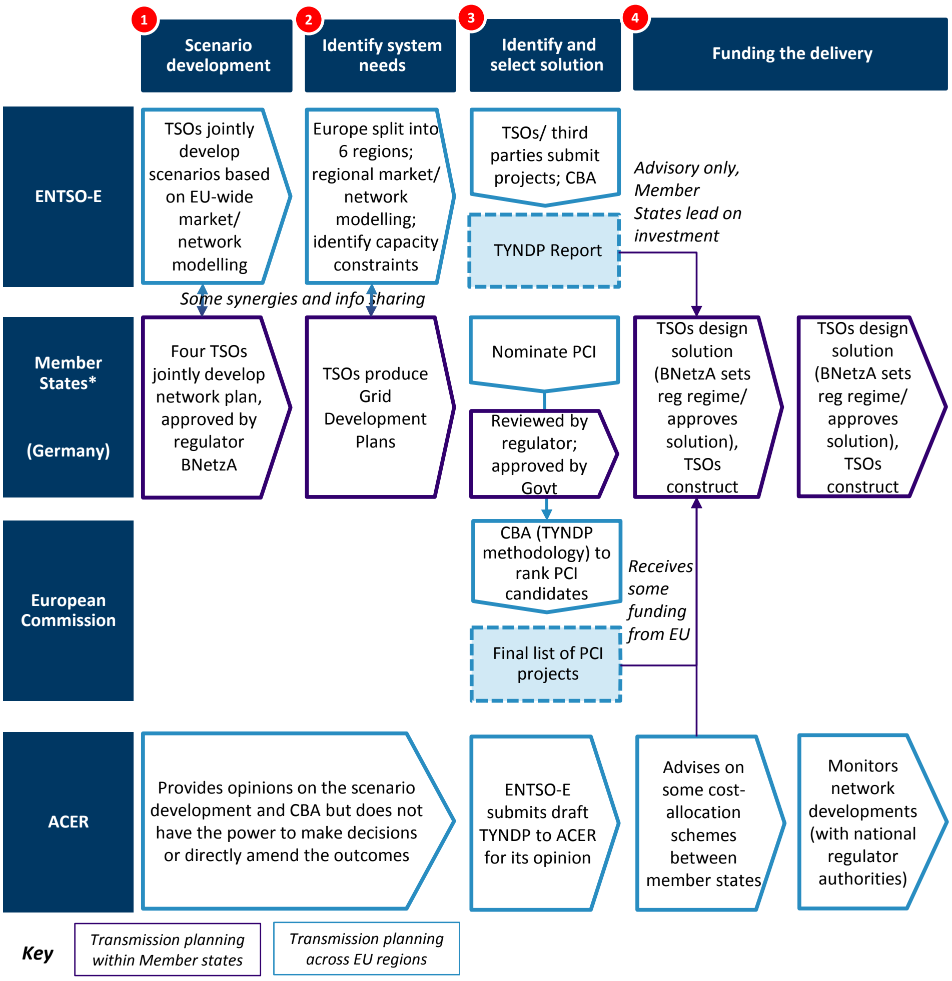
C. European transmission planning

A1.129 This section focuses on transmission planning on the European-wide level and also describes the interplay between the regional and national planning approaches.

A1.130 In Europe, each member state has at least one SO and electricity regulator (also known as a National Regulatory Authority or NRA). The SOs in most Member States are integrated with the TO-arm with varying degrees of functional separation. Under the Third Energy Package set by the European Commission, ENTSO-E was set up as a network to promote the coordination and cooperation of TSOs across Member States to achieve EU energy policy goals. Similarly, ACER was set up as an agency to promote the coordination and cooperation of NRAs across Member States.

A1.131 An overview of the European approach to transmission planning is presented in Figure A1- 7 below.

Figure A1- 7: Overview of European transmission planning



Source: FTI-CL Energy

Notes: 'Member States' in this context refers to both national regulators and the Government. Germany is split into four separate regions under ENTSO-E's regional modelling.

A1.132 As shown in Figure A1- 7 above, the ENTSO-E[235] oversees the transmission planning assessments for cross-border transmission investments to develop the Ten-Year Network Development Plan ("TYNDP"). A new version of the TYNDP is developed every two years (with the most recent version dating from 2016, and the 2018 version being currently finalised).

A1.133 In conjunction, Member States and the EC contribute by nominating and assessing Projects of Common Interest ("PCI") which are key transmission projects that have been identified as having greater importance to help the EU achieve policy and decarbonisation objectives. These can include both intra-regional transmission links, cross-border projects (AC or DC interconnectors) as well as other assets (e.g. storage). PCIs might benefit from an accelerated planning process and might receive additional funding from the Connecting Europe Facility ("CEF"). Under Regulation 347/2013, Article 12, PCIs may also apply to the national regulatory authorities to have their revenues regulated and recovered from transmission charges. Projects identified in the TYNDP and the PCI scheme are advisory only (i.e. there is no 'mandate' for the local TSOs to develop them).

A1.134 The Agency for the Cooperation of Energy Regulators ("ACER") is involved in the development of EU-wide plans and regulation, coordinating regional and cross-regional initiatives, monitoring ENTSO-E, commenting on the coherence of the TYNDP with national plans, and providing an opinion of the draft list of PCI projects.[236] ACER may also take on some of the NRAs' roles in situations where the NRAs refer specific cases to ACER for an assessment (for example, NRAs may choose to refer the assessment of regulatory exemptions for cross-border interconnectors to ACER for a decision).

235 The ENTSO-E is an entity comprised of 43 TSOs from 36 European countries. It was created to facilitate the liberalisation of the electricity market, and has legal mandates to perform various advisory functions under EU law. ENTSO-E aims to support the optimal functioning of the European energy market, integrate renewable energy options, develop solutions to future energy needs, and help regional cooperation.

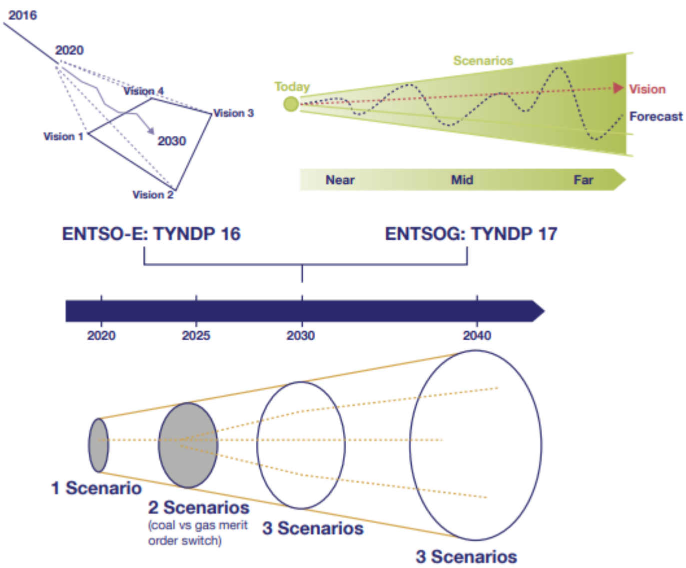
236 ENTSO-E, Continental Central East Regional Investment Plan 2017; ACER, Third Edition of the Agency's Summary Report on Cross-Border Cost Allocation Decisions Status update as of March 2018, 18 May 2018.

Scenario development

A1.135 The TYNDP process starts by developing scenarios that are used to assess potential European projects in a CBA. For the most recent TYNDP in 2018, the scenarios have been developed as a joint planning exercise between ENTSO-E and ENTSO-G (the European Network of Transmission System Operators for Gas) as well as other stakeholders. The time horizon in the 2018 TYNDP extends to 2040 which enables the analysis to consider long-term impacts in line with decarbonisation objectives.[237]

A1.136 This most recent TYNDP adopts a new methodology to develop scenarios by increasing the number of scenarios from one to three from the near-term to the long-term. This contrasts with the previous TYNDP where four 'Visions' were adopted depending the assumptions of a loose versus a strong European framework and whether the EU is on track with 2050 objectives. Figure A1- 8 below illustrates the latest framework used to develop the current scenarios.[238]

Figure A1- 8: TYNDP 2018 scenario framework



237 ENTSO-E (2018) TYNDP 2018, Scenario Report – Main Report.

238 ENTSO-E, TYNDP 2018 Scenario Development Report, Final after public consultation.

Source: ENTSO-E, TYNDP 2018 Scenario Development Report, Final after public consultation.

A1.137 The three scenarios are:[239]

- **Sustainable Transition**: this scenario assumes targets are reached through national regulation, emission trading schemes and subsidies.
- **Distributed Generation**: this scenario assumes high decentralisation, i.e. considerable small-scale generation, batteries and fuel-switching and 'active consumers'.
- **Global Climate Action**: This scenario assumes a significant large-scale renewables development in both electricity and gas sectors towards global decarbonisation.

A1.138 The ENTSO-E scenarios are designed to be representative of at least two of the following time horizons:[240]

- **Mid-term** (5 to 10 years): Mid-term analysis should be based on forecasts for this period, and may be based on long-term analysis from previous publications of the TYNDP;
- **Long-term** (10 to 20 years): the ENTSO-E scenarios developed will lie in this period, and the realised future pathway should fall in the range of these scenarios with a high level of certainty; and
- **Very long-term** (30 to 40 years): should be based on the ENTSO-E 2050-reports.

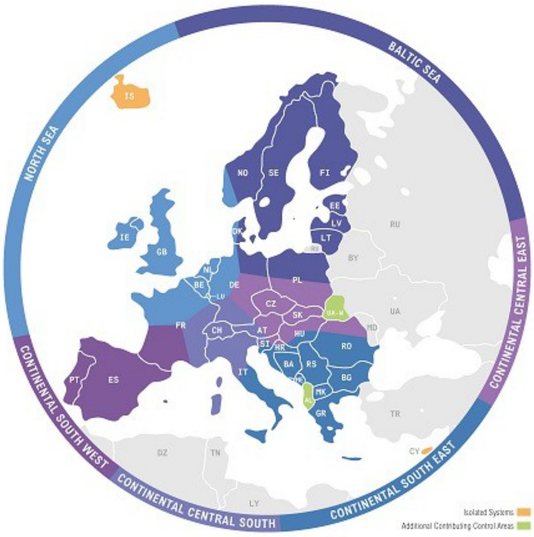
Identify system needs

A1.139 ENTSO-E's Regional Investment Plans identify system needs at a regional level. The plans are separated into six regions (North Sea, Baltic Sea, Continent Central East, Continental South East, Continental Central South and Continental South West), which are shown in Figure A1- 9 below.

[239] An extra scenario has been developed by the European Commission. This scenario assumes 2030 targets being met, but including an energy efficiency target of 30%.

[240] ENTSO-E, Guideline for Cost Benefit Analysis of Grid Development Projects, Draft for public consultation, 25 April – 31 May.

Figure A1- 9: ENTSO-E regions



Source: ENTSO-E, The Ten-Year Network Development Plan

A1.140 Some European countries belong to more than one region: for example, France is included in three regions: North Sea, Continental South West and Continental Central South. Similarly, Norway belongs both to the North Sea region and the Baltic Sea region. This is illustrated in the figure above by using multiple colours for a given country. Some countries are not included as they represent 'isolated areas' – for example Cyprus and Iceland fall in this category.

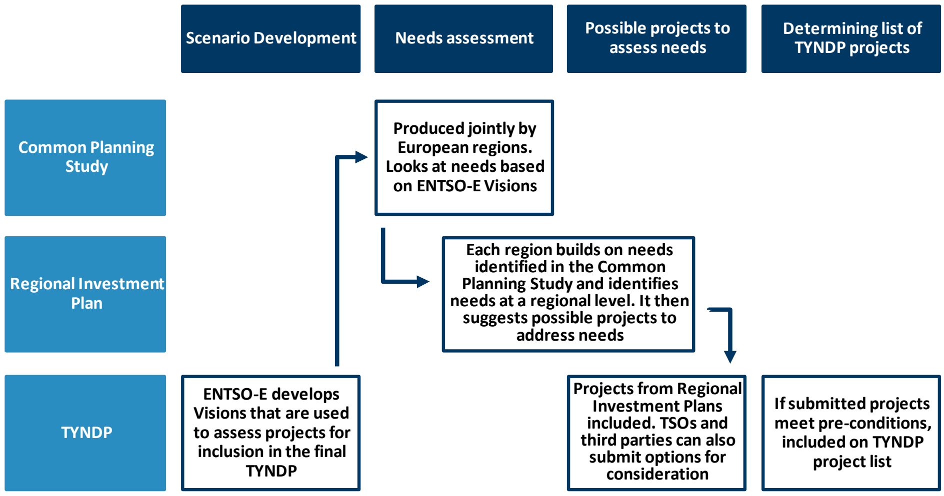
A1.141 The Regional Investment Plans identify potential projects, based on the needs identified in the Common Planning Study (produced jointly by the European regions). The TYNDP includes the projects in the Regional Investment Plans,[241] but explores the options at greater depth (for example, a CBA is performed) and takes a pan-European, rather than regional, perspective.[242] The interaction between these publications is shown in Figure A1- 10 below.

---

241 Other options can also be submitted by TSOs and third parties for consideration in the TYNDP.

242 ENTSO-E, Regional Investment Plan 2015 North Sea region, Final version after public consultation, 30 October 2015.

Figure A1- 10: Interaction between the Common Planning Study, Regional Investment Plans and TYNDP



Source: FTI-CL Energy

A1.142 The TYNDP looks at Europe's future transmission needs. ENTSO-E opens a one-month application window, during which time TSOs or third parties may submit projects for consideration. TSOs and third parties initially submit transmission projects that are being developed or being considered for development in response to an identified need. These submissions are then assessed against a set of pre-conditions, and if met, the project is included in the TYNDP report. The pre-conditions are: [243]

- a project promoter must meet regulatory requirements outlined under EU Guidelines;
- fulfil the technical requirements of pan-European significant projects, as outlined under EU Guidelines; and
- all relevant information should be provided to allow ENTSO-E to undertake a CBA and make an informed assessment.

243 Pre-conditions are not directly related to the assessment of the investment itself. European Commission, Guidelines on equal treatment and transparency criteria to be applied by ENTSO-E when developing its TYNDP as set out in Annex III 2(5) of Regulation (EU) No 347/2013, February 2015.

A1.143 For example, in the TYNDP 2016, ENTSO-E assessed a total of 199 projects of different types and at various stages of development.[244] The final 2016 TYNDP supported approximately EUR 150 billion in investment.[245]

A1.144 The sharing of information, facilitated by ENTSO-E, enhances transparency between the TSOs that helps identify weaknesses in the transmission network.

A1.145 The TYNDP is a pan-European view of the potential investment projects. However, this is performed independently (and not necessarily consistently) with the national and regional planning scenarios. Additionally, the assumptions and methodology used by ENTSO-E differ from national TSOs, hence the value attributed to various projects may differ.[246] In general, the TSOs create national plans[247] that are fed into the TYNDP via TSO participation in the TYNDP development process.

A1.146 The Common Planning Study is a means for the ENTSO-E member TSOs to coordinate the identification of needs. The TSOs use common methodologies to look at the expected flow of power in Europe in 2030 under the four ENTSO-E Visions. The objective is to identify bottlenecks, expected transmission capacity, and hence identify system needs. The output of the Planning Study is a series of potential infrastructure projects that may be included in the TYNDP.[248]

A1.147 Furthermore, ENTSO-E oversees regional operational coordination between TSOs via Regional Security Coordination Initiatives ("RSCIs"). The aim of RSCIs is to provide TSOs with an overview of electricity flows and potential risks to energy security at a regional level. However, full decision-making responsibility lies with the TSOs.[249]

---

244 ENTSO-E, Project list TYNDP 2016 assessments.

245 ENTSO-E, Executive Report, 20 December 2016.

246 ACER, CBA methodologies for electricity transmission infrastructure and scenarios for energy and power system planning, May 2016.

247 In Germany, for example, the four TSOs work together to create a national transmission plan.

248 ENTSO-E, The Ten-Year Network Development Plan.

249 ENTSO-E, ENTSO-E Policy Paper: Future TSO Coordination for Europe, November 2014.

Identify options and select solution

A1.148 The potential TYNDP projects (i.e. those that meet the selection pre-conditions) are assessed in a CBA under each ENTSO-E Vision. The CBA is a combined monetary benefit analysis and multi-criteria assessment analysis. This approach allows non-monetised benefits to be included in the assessment.[250]

A1.149 ENTSO-E refers to individual transmission elements (for example, lines, cables, and substations) as "investments" and a group of transmission investments which are complementary to each other as "projects". In addition, before the CBA commences, transmission boundaries are assessed to determine if potential investments or projects should be clustered. Clusters are a group of transmission investments that are complementary, have linked benefits, achieve a common measurable goal, and are in the same geographic area or transmission corridor. If investments are clustered, the CBA assesses the cluster rather than the individual components. The following criteria must be met for a group of investments or projects to be considered a cluster:[251]

- Each investment included in the cluster should contribute at least 20% to the total Grid Transmission Capacity increase; and
- The commissioning dates for each investment should be within five years of each other.

A1.150 The data needed to undertake the TYNDP CBA is sourced from Regional Market Studies and Network Studies. The CBA considers nine indicators, these are:[252]

- ***Environmental impact***: impact on nature and biodiversity;
- ***Social impact***: impact on local population;
- ***Improved security of supply***: adequate and secure supply of electricity under ordinary conditions;

---

250 ACER, CBA methodologies for electricity transmission infrastructure and scenarios for energy and power system planning, May 2016.

251 ACER, CBA methodologies for electricity transmission infrastructure and scenarios for energy and power system planning, May 2016.

252 ACER, CBA methodologies for electricity transmission infrastructure and scenarios for energy and power system planning, May 2016.

- ***Socio-economic welfare***: ability to reduce congestion and provide adequate grid transfer capability so that electricity can be traded in an economically efficient manner;
- ***RES integration***: connection of new RES plants;
- ***Variation in losses***: considers thermal losses in the system;
- ***Variation in CO_2 emissions***: considers CO_2 emissions;
- ***Technical resilience/system safety***: ability of system to withstand extreme system conditions; and
- ***Robustness/flexibility***: ability to include future development scenarios.

A1.151 The calculation of CBA indicators will be done under one of the following two cases:[253]

- ***Take out one at the time***: where the project is assessed against the whole forecast network, and the state of the world where the project does not exist is compared to the state where it is the last investment to be commissioned; or
- ***Put in one at the time***: where the project is assessed against the current existing network without any future TYNDP project.

A1.152 The CBA calculates the net economic benefits of investing in a particular project compared to the counterfactual of not undertaking project, and hence does not include transfers (e.g. transfers of economic surplus between consumers and producers) in the calculation. ENTSO-E is concerned with economic benefits regardless of which stakeholder benefits. In analysing costs, all costs should be identified but only incremental costs incurred as the result of the project are relevant. Economic costs, as opposed to accounting costs, incurred by all stakeholders are included in the CBA.[254]

---

253 ACER, CBA methodologies for electricity transmission infrastructure and scenarios for energy and power system planning, May 2016.

254 ENTSO-E (Prepared by Frontier Economics and Consentec), Cost Benefit Analysis for Electricity Balancing – general methodology, 20 February 2015; ACER, CBA methodologies for electricity transmission infrastructure and scenarios for energy and power system planning, May 2016.

A1.153 ENTSO-E uses a real discount rate of 4%, a 25-year time horizon, and zero residual value to assess all projects across Europe.[255]

A1.154 The published TYNDP includes a description of the future energy requirements at a national and pan-European level, and the CBA results for each transmission project considered. The TYNDP aims to support national and regional decision makers, and is the basis for selection as a PCI.[256]

A1.155 ACER provides its opinion and recommendations to ENTSO-E with regards to the TYNDP. It assesses whether the TYNDP is non-discriminatory, promotes effective competition and an efficient market, contributes to a sufficient level of cross-border interconnection, is not inconsistent with national plans, and complies with the Third Energy Package provisions.[257] ACER also monitors the implementation of transmission plans and cross-border infrastructure projects. If the actual implementation differs from the planned implementation, ACER will investigate and make a report with recommendations to the relevant TSOs, national regulators, and other competent bodies.[258]

---

[255] ENTSO-E, ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects, 5 February 2015.

[256] ENTSO-E, ENTSO-E at a glance.

[257] This is legislation enacted by the European Union that covers (1) the unbundling of energy supplier from network operators; (2) strengthening the independence of national regulators; (3) establishing ACER; (4) establishing ENTSO and ensuring cross-border cooperation between TSOs; and (5) improving transparency in retail markets.

European Commission, Market legislation.

[258] ACER, Network development.

A1.156 Only projects included in the ENTSO-E (or ENTSO-G) TYNDP can be considered by the EC as a PCI. The CBA methodology used in the TYNDP is used as the basis to assess and rank PCIs. If selected, these projects are eligible for EU funding, which will not cover the cost of the entire project, but will contribute to the development costs.[259] PCIs are infrastructure projects that aim to enhance the European energy market and help achieve energy objectives. Funding will only be granted if, in the absence of financial assistance, the project is not commercially viable. There are some advantages to being classified as a PCI: the projects may be eligible for funding during the development process[260], they also benefit from an accelerated regulatory approval process, and they can also apply to the national regulatory authorities to have their revenues regulated and recovered from transmission charges (Regulation 347/2013).

A1.157 In order to be included on the list of PCIs, the projects should meet the following criteria:[261]

- Have a significant impact on at least two EU Member States;
- Enhance market integration and contribute to the integration of EU Member States' networks;
- Increase competition by offering alternatives to consumers;
- Enhance security of supply; and
- Contribute to sustainability.

---

259 For example, some of the GB interconnectors under development have been designated as PCI and have therefore received a contribution from the EU towards their development costs. For example, NorthConnect received €10m from the EU. North Connect, Europe multi-million cash boost to Scotland – Norway electricity connection.

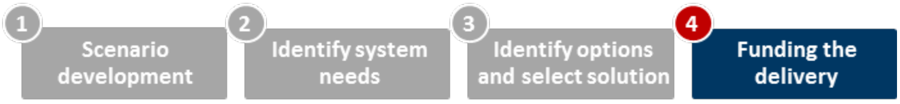
260 Several interconnector developers have received direct funding through the Connecting Europe Facility, including IFA 2 (€6m), Viking Link (€2.8m) and NorthConnect (€10.76m). EC (2016), List of actions selected for receiving financial assistance under the second CEF Energy 2016 call for proposals; 4cOffshore (2018) Viking Link gets EC funding; EC (2015), List of actions selected for receiving financial assistance under the second CEF Energy 2015 call for proposals. (Accessed at: https://ec.europa.eu/energy/sites/ener/files/documents/list_of_all_projects_receiving_eu_support_under_the_current_call.pdf; https://www.4coffshore.com/windfarms/viking-link-gets-ec-funding-nid7010.html; https://ec.europa.eu/energy/sites/ener/files/documents/List%20of%20selected%20actions%20CEF%202015-2%28final%29.pdf).

261 EU, Questions and answers on the projects of common interest (PCIs) in energy and the electricity interconnection target, 24 November 2017.

A1.158 PCIs are *"key infrastructure projects, especially cross-border projects, that link the energy systems of EU countries"*.[262] Südlink, an interconnector between the north and south of Germany,[263] was deemed to meet the PCI criteria as it will:

- increase the flow capacity between the north and south of Germany;
- benefit neighbouring countries such as Hungary, Poland, the Czech Republic, and Slovakia by helping to avoid spill-overs into their grids caused by surges in German generation; and
- facilitate the integration of renewables (from the north) into the grid, hence encouraging investment.

Funding the delivery of the asset



A1.159 The delivery and the funding of a transmission solution are led by individual Member States. These are often TSO-driven on a national level (recognising that the TO and SO functions are a single entity) subject to reviews and approvals by the regulator and/or Government.

A1.160 Specifically for interconnectors, cross-border cost allocation ("CBCA") arrangements were established in 2013 to improve the allocation of cost of transmission investments between Member States. Projects developers (or promoters of the projects) can refer a specific project to the regulators involved with the investment to decide on how the cost should be allocated. If the regulators are unable to reach agreement, they will refer the project to the ACER to decide on the cost allocation.

---

262 European Commission, Project of Common Interest: Südlink – The North-South German Interconnector.

263 Germany is separated into four regions, each with its own TSO.

A1.161 If ACER is tasked to determine the CBCA, ACER will update the CBA and allocate costs based on this updated assessment, as well as determine the impact of the project on tariffs. In general, ACER will allocate the costs to the entities that are responsible for the area that the project is sited in (i.e. the beneficiaries-pay principle). However, in cases where the infrastructure is not physically located in a particular region, but the region is a net beneficiary of the asset by more than 10%, the region may still be allocated some of the investment costs.[264] This may be the case for example where an intra-state investment in transmission capacity enhances the transit capacity and therefore enables a neighbouring region to benefit from increased volume of power flows.

A1.162 It is most commonly the case that 100% of investment costs are allocated in the CBCA; however there have been instances where increases in transmission tariffs have resulted in less than complete investment cost allocation. In these cases, EU funds (for example, PCI grants) are used to fill the financing gap.[265]

A1.163 While there is no beneficiary pays model in Europe per se, it is notable that occasionally classes of potential beneficiaries can find routes to provide financial support to underpin the construction of interconnectors that they believe will be in their economic interest.

- For example, NorthConnect (a planned link between Norway and Scotland) is likely to facilitate greater exports from Norway is being developed by Nordic generators.[266]
- Similarly, Piemonte Savoia (a France-Italy link) is promoted by a group of Italian energy-intensive industrial customers that would be likely to benefit from increased imports of low cost electricity from France into Northern Italy.[267]

---

264 ACER, Decision of the Agency for the Cooperation of Energy Regulators No 02/2015, 16 April 2015; Energy Community, Explanatory Notes on the implementation of EU Regulation 347/2013 – MC decision 2015/09, Part II: The Cross-Border Cost Allocation Process.

265 ACER, Overview of past investment request decisions including CBCA, 2 February 2016.

266 These include Agder Energi, E-CO, Lyse Produksjon and Vattenfall.

267 EC (2016) Commission Decision of 9.12.2016 on the exemption of Piemonte Savoia S.r.l (Italy) under Article 17 of Regulation (EC) No. 714/2009 for an electricity interconnector between Italy and France.

- Arguably in GB, the regulator, Ofgem, sanctions customer support of interconnector projects if it considers that GB consumers will benefit on account of increased imports.

A1.164 In addition, EC has put in place a mechanism known as inter-TSO compensation (“ITC”) to mitigate the adverse impact on stakeholders following the re-distribution of benefits between consumers and producers within or between regions following the construction of a new interconnector. The ITC scheme was established by the ENTSO-E to compensate TSOs for costs incurred from hosting cross-border electricity flows on national transmission systems. TSOs that are part of the scheme receive compensation from the ITC Fund for transits they carry, and contribute to the Fund based on their net import and export flows. The ITC enables TSOs in neighbouring countries to partially compensate each other for hosting ‘transit’ flows, and specifically for:[268]

- the costs of losses incurred by national transmission systems as a result of hosting cross-border flows of electricity; and
- the costs of making infrastructure available to host cross-border flows of electricity.

A1.165 ACER is responsible for overseeing the implementation of the ITC mechanism, and reporting to the EC on the implementation of the ITC mechanism and the state of the ITC Fund annually.[269]

[268] ACER (2017) Report to the European Commission on the implementation of the ITC mechanism in 2016.

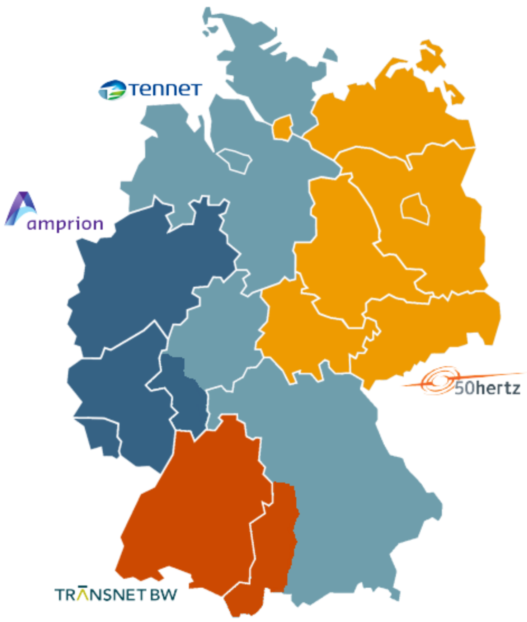
[269] ACER (2017) Report to the European Commission on the implementation of the ITC mechanism in 2016.

D. German transmission planning

A1.166 The TSOs and regulators of individual Member States are responsible for the transmission planning within the Member State itself, and they are also ultimately responsible for the design and delivery of the projects that may be identified through the TYNDP and/or as PCIs.

A1.167 In this case study, we focus on the German TSOs as an example of a European Union Member State. Germany has four TSOs (50Hertz, Amprion, Tennet, and TransnetBW), each covering a separate region. Germany is a particularly relevant example as it also faces well-known internal congestion challenges resulting from rapid construction of renewable generation, particularly offshore wind, in the North of the country, and demand shortfalls in the South. Figure A1- 11 below shows the parts of Germany covered by each TSO:

Figure A1- 11: Map of German TSOs



Source: Blog.Stromhaltig, Der Weg des Stroms – vom Kraftwerk bis zur Steckdose, 22 February 2014.

A1.168 Even though Germany has four TSOs, Germany as a whole operates as market with a single price zone.[270] Each TSO is mandated to *"operate and maintain a stable, reliable and efficient power supply grid in an unbiased manner, optimising, enhancing and expanding this in line with demand"*.[271] The TSOs, in collaboration with the regulator Bundesnetzagentur ("BNetzA"), produces the German Grid Development Plan ("GDP") which plans the onshore networks on a biannual basis.[272] This plan is developed in conjunction with ENTSO-E's TYNDP and both plans are used as inputs to each other.

Scenario development

A1.169 The GDP is produced every two years by BNetzA in collaboration with the four German TSOs. There are separate reports for onshore and offshore transmission investments, but they are closely linked.[273]

A1.170 For the GDP, the TSOs are responsible for developing four scenarios, that are reviewed and approved by BNetzA and opened to consultation with relevant third parties (for example, network operators). The 2017 scenarios consider the level of innovation, and the rate of transformation towards an energy secure, low-carbon, affordable energy sector (known as "Energiewende"). Three scenarios are for a time horizon up to 2030, and one is for up to 2035. There is no requirement to consider the scenarios outlined by ENTSO-E but there have been calls for greater alignment between the scenarios.[274]

270 While Germany has a single price zone, there are some locational elements for network charges.

271 Section 11, German Energy Management Act

272 Historically, TSOs produce a separate offshore network plan. This responsibility is being moved to the Federal Maritime and Hydrographic Agency.

273 Netzentwicklungsplan: Strom, Grid Development Plan 2030 (2017), second draft (EN).

274 Netzentwicklungsplan Strom, Grid Development Plan 2030 (2017), second draft (EN).

Identify system needs

A1.171 The German TSOs identify system needs based on the four scenarios as part of the GDP. This details the optimisation, expansion, and reinforcement measures required to address the needs of the electricity grid.

A1.172 The GDP aims to use a combination of AC and DC transmission lines to optimise how needs are met in each of the scenarios. The GDP recognises that projects under the Federal Requirements Plan are likely insufficient to maintain reliability, and hence identifies and proposes additional network development requirements.

A1.173 The use of AC transmission lines to develop the existing network (i.e. network deepening) is generally used for shorter distances (e.g. due to lower costs per km of line relative to DC lines). These projects are set out under the prevailing Federal Requirements Plan which is led by BNetzA and hence are used as inputs into the GDP.

A1.174 ‘Ultra-high voltage’ DC transmission lines are also used to for long-distance transmission needs within Germany. The projects where a DC line is preferred are often considered to have additional strategic importance, in particular to connect surplus generation in northern Germany with the deficit in southern Germany. DC transmission lines are preferred over long distances because they are able to move large amounts of power across large distances with less electric loss, and exert greater technical control over the direction and the magnitude of the flow, compared to AC lines.

Box A1- 5: Coordinating transmission assets and offshore wind farms[275]

Prior to 2013, grid connection in Germany for offshore wind farms was legally guaranteed. The government ensured that the relevant TSO provided a grid connection. However, the TSOs responsible for connecting wind farms faced challenges relating to an immature technology, the supply chain, and project finance. This delayed grid connection, leading to revenue losses, increased risks for wind park developers, and increased costs to consumers (who ultimately bear the costs).

In response to these issues stemming from this 'reactive' model, the German authorities developed a 'proactive' transmission model. Under this model, a grid plan, the O-GDP, was produced by the German TSOs and was intended to serve as an objective, transparent and non-discriminatory allocation procedure. Under this approach, multiple offshore wind farms can be considered a 'cluster' and connected to the grid in a way where transmission assets are shared across wind farms. A benefit of this is that if the connection of renewable energy generation is defined in clusters, it is likely to be more attractive (producing greater total benefits).

Under the updated regime, the TSOs produce the O-GDP based on the outlook of projects and system needs. The published O-GDP outlines required transmission projects and provides a reliable timeline for grid connection. Once the date of grid connection has been published the TSO and generator agree on a realisation plan that specifies project completion dates.

As an example of projects enabled by the O-GDP, the Borwin project is a multi-phase connection project for a series of offshore wind farms off the coast of Germany in the North Sea. The Borwin project delivered economies-of-scale benefits by coordinating the connection of two wind farms, such that two converter stations were required rather than four, and one cable to shore was used rather than two. ENTSO-E defines this project as a cluster in its TYNDP, as does Germany in its O-GDP.

Denmark, Belgium and the Netherlands have adopted a similar model to Germany by proactively planning for the offshore networks and the associated offshore wind farms.

---

275 Florence School of Regulation, UK v DE two different songs for transporting energy to shore, 13 September 2016; Progress on Meshed HVDC Offshore Transmission Networks, Intermediate Deliverable – Economic framework for offshore grid planning, 30 June 2017; Wind Power Monthly, Clearer path ahead under new grid connection rules, April 2013; Progress on Meshed HVDC Offshore Transmission Networks, Offshore grid connection 15 percent cost reduction in the tender for DolWin6, 20 July 2017; Wind Europe, Community projects steal the show in German onshore wind auction, 24 May 2017.

Identify options and select solution

A1.175 The four German TSOs identify potential solutions to meet the system needs in each of the four scenarios as part of the GDP. This stage is linked closely with the identification of system needs. Once the system need has been identified, specific projects are then identified in each of the scenarios in the GDP. These projects are reviewed by BNetzA and opened to third-party consultation with a final version approved by BNetzA.

A1.176 The final GDP is a set of projects that the TSOs propose to build.[276] BNetzA has the power to require TSOs to adjust the content of the GDP (i.e. project plans). The final GDP is passed to the Federal Government, who publishes a Federal Requirements Plan. This formalises the 'need for' the transmission project, and specifies the start and end points of the line (but not the route).

A1.177 BNetzA has the right to suggest changes to the projects included in the GDP, or suggest new projects that it believes are necessary under all scenarios ("no regret" investments). For example, BNetzA approved 96 out of 165 projects included in the 2017 draft GDP, and suggested 16 new projects that are "*absolutely necessary and sustainable, no matter what direction is followed in the future*." A public consultation occurs before BNetzA approves the GDP. Before the 2017 GDP was approved, BNetzA considered 15,000 responses submitted by any interested party, all of which were evaluated.[277] Third parties could propose changes to projects, or new projects, but whether or not to incorporate the submission is at the discretion of BNetzA.

---

276 In Germany, it is unclear what the relative roles are between the SO and the TO functions in forming the transmission plan. Unlike GB, there is no mandate from the regulator to ensure functional separation between the two.

277 Bundesnetzagentur, Bundesnetzagentur approves network development plans 2017-2030 and publishes environmental report, 22 December 2017.

A1.178 TSOs follow the NOVA principle in developing projects for the GDP.[278] NOVA is a German acronym (Netzoptimierung, -verstärkung und -ausbau) that translates to network optimisation, enhancement, and expansion of the grid. Under NOVA, the order of decreasing project priority is network optimisation, network development, and network expansion. The development of a new transmission network, for example the construction of a power line, will only be considered once all viable options for optimisation or development of the existing network have been proven insufficient.[279]

A1.179 To assess the impacts of proposed solutions, the GDP sets out, qualitatively, based on the network modelling and the reliability criteria, three distinct impacts for each solution across each scenario. These are:

- the effectiveness of the investment, which includes the impact on congestion and the impact on the grid if a parallel line fails;
- the necessity of the investment including the average utilisation; and
- the environmental impact which is further assessed in a separate environmental report.

A1.180 In conjunction with the identified solution, stakeholder responses, which might propose alternative solutions, must be considered.

A1.181 The GDP process ensures coordination between the TSOs because the German TSOs work together to produce the GDP. For example, SuedOstLink and Südlink are interregional investments that involve multiple TSOs, and were originally published in the GDP. Both projects are transmission lines between the North and South that are designed to address the imbalance between excess generation in the north and shortages in the south.[280] The relevant TSOs then work together to ensure the successful completion of the project.[281]

---

278 Netzentwicklungsplan Strom, Grid Development Plan 2030 (2017), second draft (EN).

279 Netzentwicklungsplan Strom, Conclusion: Power Grid Development Plan 2025, Version 2015, 2nd Draft.

280 For example, German nuclear reactors are planned to be closed by 2022, and many of the reactors are in the south, hence there is a need to replace this source of electricity in the south (S&P Global Platts, German Südlink grid project delayed to 2025 as cables go underground, 28 September 2016).

281 50Hertz, SuedOstLink.

A1.182 The joint development of projects is coordinated by BNetzA and is a deliberate outcome of how the GDP process has been designed in Germany. Being included in the GDP and subsequently approved, is recognition that the project is required to address a genuine system need.

A1.183 Once the GDP is completed and approved by BNetzA, the proposed list of solutions that span across regions within Germany is included in an updated Federal Requirements Plan. BNetzA has the authority to decide on the route corridors of which to invest in, as well as the cable routes in the planning approval procedure. Third parties are invited to participate in the conference and provide feedback that will be considered by BNetzA.[282] For smaller transmission solutions that only affect a single state, the state authority is responsible.

A1.184 The planning process for offshore transmission is the same as for onshore transmission, but the results are published in a separate Offshore Grid Development Plan (O-GDP). The process of producing the O-GDP is very similar, and uses the same scenarios, as the GDP. In parallel, the Federal Maritime and Hydrographic Agency currently publish a Spatial Offshore Grid Plan that identifies offshore wind farms that are deemed suitable for 'collective' grid connections (e.g. through clusters), as well as the connecting cable routes. The two documents are linked: the O-GDP must take into account the specifications of the Spatial Offshore Grid Plan in order to set out a long-term plan for the implementation of the grid reinforcements.

A1.185 The two planning tools (the Spatial Offshore Grid Plan and the O-GDP) are both set to be merged and replaced[283] by a single Flächenentwicklungsplan, or Area Development Plan ("ADP") in English.[284] The ADP will cover all aspects of offshore grid development. In addition to the cable routes or corridors for offshore grid connection, and possible cross connections between facilities, the new ADP will detail offshore areas to come under tender for development, expected installation of wind turbines, general planning principles and technical specifications.[285]

---

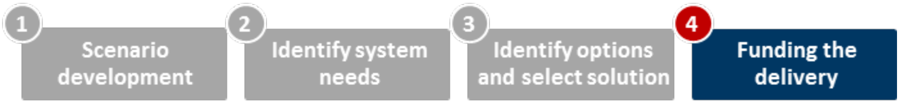
[282] Bundesnetzagentur, Federal sector planning or regional planning procedure? (translated from German).

[283] Both of the current documents have been discontinued as at the end of 2017.

[284] Netzentwicklungsplan Strom, Offshore Grid Development Plan 2030, Version 2017, second draft (EN), 16 June 2017; Netzentwicklungsplan Strom, Offshore Grid Development Plan 2030 (2017).

[285] BSH, Draft of the Spatial Offshore Grid Plan for the German Exclusive Economic Zone of the Baltic Sea 2016/2017 (unofficial translation), June 2017.

Funding the delivery of the asset



A1.186 TSOs are responsible for constructing onshore and offshore transmission assets in their respective regions, as well as for owning and operating them.[286] The cost of connection (both onshore and offshore) is socialised and charged by the TSOs to consumers via connection charges.[287]

A1.187 For example, the SuedOstLink is a transmission line that will link the north of Germany, where there is excess generation, with the south, where there is a deficiency in generation. This transmission line is a joint project between two TSOs, TenneT and 50Hertz, as this project will cover areas managed by both TSOs. Each will plan, develop, and pay for the parts of the project that cover their territory. SuedOstLink has been classified as a PCI, and will receive EU funding – highlighting the interplay between ENTSO-E and individual Member States.[288]

A1.188 BNetzA and state regulatory authorities are responsible for regulating the electricity grid. State authorities will regulate operators with fewer than 100,000 customers on grids that do not cross state borders, while BNetzA will regulate all other operators. BNetzA is concerned with creating conditions for fair and effective competition in upstream and downstream markets, including:[289]

- ensuring non-discriminatory grid access;
- controlling grid access tariffs charged by grid operators;
- safeguarding against anti-competitive practices; and
- monitoring the implementation of the regulatory regime.

---

286 Reuters, German energy regulator receives plans for two big power lines, 8 March 2017; Florence School of Regulation, UK v DE: two different songs for transporting energy to shore, 13 September 2016.

287 Florence School of Regulation, UK v DE: two different songs for transporting energy to shore, 13 September 2016; North Sea Grid, WP5 Final Report: Alternative cross-border cost allocation methods for sharing benefits and costs of integrated offshore grid infrastructures.

288 50 Hertz, SuedOstLink; Wind Power Monthly, EU invests in renewable energy-integrating interconnectors, 25 January 2018.

289 Thomson Reuter Practical Law, Electricity regulation in Germany: overview.

Glossary

Term	Definition
ACER	Agency for the Cooperation of Energy Regulators
ACT	Australian Capital Territory
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AER February 2018 consultation	The February 2018 consultation on various aspects of the RIT-T, issued by the AER
AER RIT-T repex revision	The 2017 AER revision of the RIT-T in respect of replacement expenditure
ANM	Active Network Management
APR	Annual Planning Report
BNetzA	Bundesnetzagentur, the German energy regulator
CATOs	Competitive Appointment of Transmission Owners
CBA	Cost-Benefit Analysis
CBCA	Cross-Border Cost Allocation
CEF	Connecting Europe Facility
COAG	Council of Australian Governments
COAG Report	The COAG Energy Council report assessing if the RIT-T remains fit for purpose in the context of the changing Australian electricity market

CREZ	Competitive Renewable Energy Zones
DFAX	Distribution Factor Analysis
EMB	Energy Market Benefit
ENTSO-E	European Network of Transmission System Operators for Electricity
EPC	Engineering Procurement Construction
ERCOT	Electric Reliability Council of Texas
ESOO	Electricity Statement of Opportunities
ETYS	Electricity Ten Year Statement, produced by National Grid
FES	Future Energy Scenarios, produced by National Grid
FTI	FTI Consulting LLP
FTI-CL Energy	Energy teams of FTI Consulting LLP and its subsidiary company, Compass Lexecon
GDP	Grid Development Plan, produced by BNetzA
GSOO	Gas Statement of Opportunities
IESO	Independent Electricity System Operator
Intra-regional	Within the same price zone
Interregional	Between different price zones
ISO-NE	Independent System Operator of New England
ISP	Integrated System Plan
ITC	Inter-TSO Compensation
ITPR	Integrated Transmission Planning and Regulation

JRG	Joint Regulator Group
LMP	Locational Marginal Pricing
LOLE	Loss of Load Expectation
LSEs	Load Serving Entities
MAT	Minimum Availability Target
MISO-SPP IPSAC	The Interregional Planning Stakeholder Advisory Committee between the Midcontinent Independent System Operator and Southwest Power Pool
MISO-SPP JOA	The Joint Operating Agreement between the Midcontinent Independent System Operator and Southwest Power Pool
MISO-SPP JPC	The Joint Planning Committee between the Midcontinent Independent System Operator and Southwest Power Pool
MVPs	Multi-Value Projects
NCSP	Northeastern Coordinated System Plan
NEM	National Electricity Market
NER	National Electricity Rules
NERC	North American Electric Reliability Corporation
NETS SQSS	National Electricity Transmission System Security and Quality of Supply Standards
NOA	Network Options Assessment, produced by National Grid
Northeastern IPSAC	The PJM and NYISO Interregional Planning Stakeholder Advisory Committee
Northeastern JIPC	The Joint PJM and NYISO ISO/RTO Planning Committee
NSL	North Sea Link interconnector

NTNDP	National Transmission Network Development Plan, produced by AEMO
NTP	National Transmission Planner
NYISO MMU	The NYISO Market Monitoring Unit
NYPSC	New York Public Service Commission
OFTO	Offshore Transmission Operator
PCI	Projects of Common Interest
PJM MMU	The PJM Market Monitoring Unit
PJM RTEP	PJM Regional Transmission Expansion Plan
Productivity Commission Report	The 2013 Australian Productivity Commission report that assessed the NEM's current regulatory framework
PSCR	The Project Specification Consultation Report, issued by ElectraNet (the TNSP)
PUCT	Public Utilities Commission of Texas
RAB	Regulatory Asset Base
RET	Renewable Energy Target
REZ	Renewable Energy Zone
RGOS	Regional Generation Outlet Study
RIT-T	Regulatory Investment Test for Transmission
RNA	Reliability Needs Assessment
RPMB	Reliability Pricing Model Benefit
RPS	Renewable Portfolio Standards
RRN	Regional Reference Nodes

RSCIs	Regional Security Coordination Initiatives
RTOs	Regional Transmission Organisations
SO	System Operator
STPR	Social Time Preferential Rate
SWW	Strategic Wider Works
TNSP	Transmission Network Service Provider
TO	Transmission Operator
TYNDP	Ten-Year Network Development Plan, produced by ENTSO-E
WACC	Weighted-average cost of capital