Competition Benefits Inputs, Assumptions and Methodology

Market Consultation

14 October 2021

Building a better working world

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1. Executive summary

EY has been engaged to prepare a proposed market competition benefits calculation inputs, assumptions and methodology report (Report) based on the Australian Energy Regulator's (AER) approved methodologies[1]. The Report presents a proposed method for the calculation of market competition benefits relating to network augmentation options that form the candidate development paths (CDP) considered in the Integrated System Plan (ISP), to be applied unless Australian Energy Market Operator (AEMO) can provide reasons why[2]: ·

- competition benefit is likely not to materially affect the outcome of the assessment of the optimal development path (ODP)[3]; or ·
- the estimated cost of undertaking the analysis to quantify the market benefit is likely to be disproportionate given the level of uncertainty regarding future outcomes.

The AER has defined the classes of AEMO ISP and RIT-T benefits[1,2]. The classes of AEMO ISP market benefits are shown in Figure 1, and have been grouped into traditional benefits and competition benefits[4]. Further, EY (consistent with the Frontier Economics[5] approach) group competition benefits into competition cost savings and competition benefits due to demand response[6].

This Report describes both groups of market competition benefits and a proposed application of the Frontier approach to calculating competition benefits. A case study which is applied in the HumeLink Project Assessment Conclusion Report (PACR)[7] is included to illustrate the methodology, noting that in the ISP, AEMO may apply the methodology to CDPs rather than an individual network augmentation option unless a narrower focus on individual elements can be justified.

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[1] AER, August 2020, *Application guidelines - Regulatory investment test for transmission*. Available at: https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20application%20guidelines%20-%2025%20August%202020.pdf Accessed 7 October 2021.

[2] AER, August 2020, *Cost benefit analysis guidelines, Guidelines to make the Integrated System Plan actionable*. Available at https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf, Accessed 7 October 2021.

[3] Note that the ODP is chosen from the set of CDPs as the suite of actionable and future ISP projects which optimises benefits to consumers given the uncertainties in the future outlook.

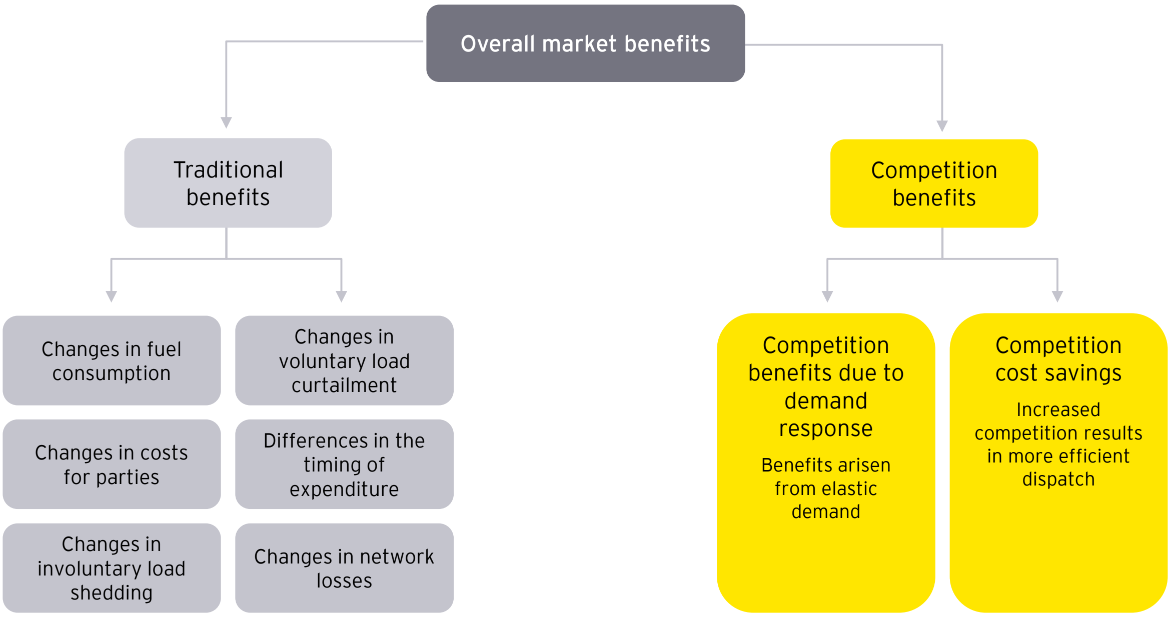
[4] Note that option value and ancillary services are other additional classes, which are modelled less often.

[5] Frontier Economics, September 2004, *Evaluating interconnection competition benefits*. Available at: https://www.aer.gov.au/system/files/Frontier%20Economics%20report%20-%20evaluating%20interconnection%20competition%20benefits%20-%20September%202004.pdf. Accessed 7 October 2021.

[6] The term "demand response" has been adopted from Frontier's 2004 report in this context meaning the long term response of electricity demand due to change in electricity price (elasticity). It is noted that this differs from the general contemporary use of the term as meaning short term demand flexibility (e.g. Wholesale Demand Response).

[7] TransGrid RIT-T website available at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network. Accessed 7 October 2021.

Figure 1: Classes of market benefits[8]



[8] The diagram is based on a combination of the AER, August 2020, *Application guidelines - Regulatory investment test for transmission* and Frontier Economics, September 2004, *Evaluating interconnection competition benefits.*

2. Introduction

EY has been engaged to prepare a proposed market competition benefits calculation inputs, assumptions and methodology report (Report) based on the Australian Energy Regulator's (AER) approved methodologies[9]. The Report presents a proposed method for the calculation of market competition benefits relating to network augmentation options that form the candidate development paths (CDP) considered in the Integrated System Plan (ISP), to be applied unless Australian Energy Market Operator (AEMO) can provide reasons why[10]:

- competition benefit is likely not to materially affect the outcome of the assessment of the optimal development path (ODP)[11]; or
- the estimated cost of undertaking the analysis to quantify the market benefit is likely to be disproportionate given the level of uncertainty regarding future outcomes.

AEMO must publish an ISP at least every two years by 30 June in accordance with the procedures outlined within rule 5.22 of the NER. The ISP establishes a whole of system plan for the efficient development of the power system that achieves power system needs for a planning horizon of at least 20 years, for the long-term interests of consumers of electricity. In this way, the ISP seeks to coordinate investment across the power system. This promotes efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity[10].

Under clause 5.22.10(c)(1) of the NER, AEMO must, in preparing an ISP, consider competition benefits as a class of market benefits that could be delivered by the development path unless AEMO can provide the reasons for not doing so[10], as mentioned above. Competition benefits are likely to accrue if a CDP could impact the bidding behaviour of generators (and other market participants) who may have a degree of market power relative to the base case[9].

Figure 2 shows the classes of market benefits[12]. For the purpose of this consultation, market benefits which have generally been considered in the ISP assessment in recent years are described as "traditional benefits". Traditional benefits (or non-competition benefits) are typically calculated by applying competitive (short-run marginal cost, SRMC) generator bid modelling. The AEMO ISP modelling framework and software tools apply an overall mathematical approach to the generation and transmission investment planning problem by minimising total cost of energy supply in a linear program optimisation.

Competition benefits, as a class of benefits, have not been explicitly assessed in the ISP to date due to the computational complexity and uncertainty surrounding future outcomes, and have been rarely modelled in recent RIT-Ts for similar reasons. An example, which will be used to illustrate the methodology in this report, is in the HumeLink PACR, where EY evaluated market competition benefits, following the Frontier approach (which ensures that the modelling avoids the risk of double counting the efficiency benefits which have already been captured in the traditional benefits)[13].

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[9] AER, August 2020, *Application guidelines - Regulatory investment test for transmission*. Available at: https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20application%20guidelines%20-%2025%20August%202020.pdf. Accessed 7 October 2021.

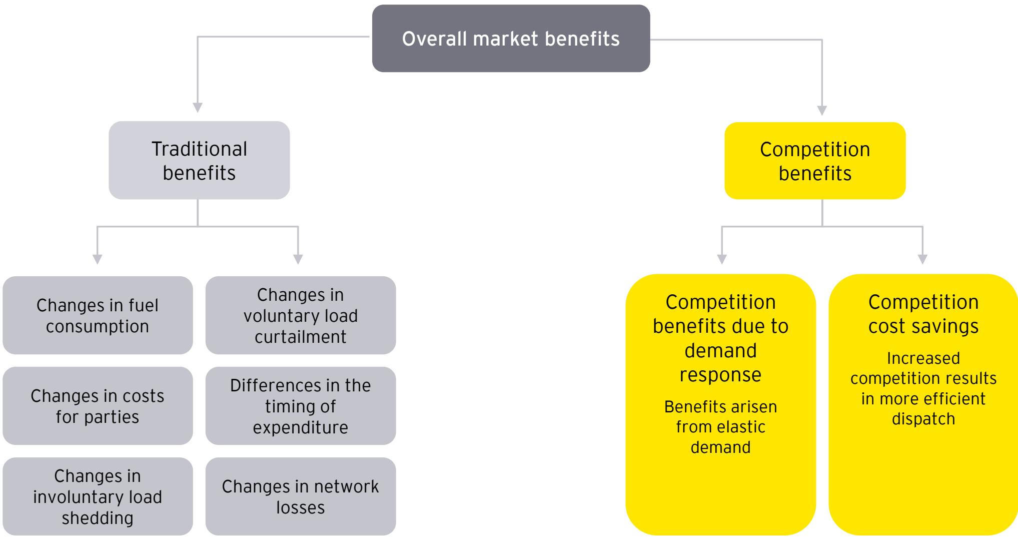
[10] AER, August 2020, *Cost benefit analysis guidelines, Guidelines to make the Integrated System Plan actionable*. Available at https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf, Accessed 7 October 2021.

[11] Note that the ODP is chosen from the set of CDPs as the suite of actionable and future ISP projects which optimises benefits to consumers given the uncertainties in the future outlook.

[12] Note that option value and ancillary services are other additional classes, which are modelled less often.

[13] TransGrid RIT-T website available at https://www.transgrid.com.au/projects-innovation/humelink. Accessed 7 October 2021.

Figure 2: Classes of market benefits[14]



The remainder of the Report is structured in the following sections:

- Chapter 3 provides an overview of the proposed competition benefits modelling and calculation methodology recommended by EY, including its categories, key modelling steps, assumptions and inputs. It illustrates this using a recent case study for HumeLink.
- Appendix A further details the proposed procedural approach to configuring the market model and the mathematics applied to calculate competition benefits.

[14] The term "demand response" has been adopted from Frontier's 2004 report in this context meaning the long-term response of electricity demand due to change in electricity price (elasticity). It is noted that this differs from the general contemporary use of the term as meaning short term demand flexibility (e.g. Wholesale Demand Response).

3. Competition benefits

Traditional classes of ISP market benefits (e.g. capital expenditure (capex), fuel, operation and maintenance) are calculated based on competitive dispatch and SRMC bidding, with the implicit assumption that the market is fully competitive. However, the SRMC-based market modelling may not capture all the market benefits of a CDP.

Under clause 5.22.10(c)(1) of the NER, AEMO must, in preparing an ISP, consider competition benefits as a class of market benefits that could be delivered by the development path unless there is a valid reason for not doing so[15]. Competition benefits are likely to apply if a CDP could impact the bidding behaviour of generators (and other market participants) who may have a degree of market power relative to the base case.

Competition benefits can be calculated when the modelling process calculates market benefits as the difference between the following present values of the economic surplus[9]:

- arising with the CDP, with bidding behaviour reflecting any market power prevailing with that CDP in place; and
- in the base case (or counterfactual case), with bidding behaviour reflecting any market power in the base case.

The AER in the RIT-T application guidelines suggest two possible approaches for the calculation of competition benefits, known as the "Biggar approach" and the "Frontier approach". Both approaches involve the same methodology for calculating the overall market benefits of a credible option of the RIT-T, (a CDP in the ISP), and result in the same total market benefits. The difference between the two approaches relates to how to differentiate the overall market benefits of a CDP between competition benefits and traditional benefits. The AER allows, by virtue of the guidelines, adoption of either approach (or another approach) for the calculation of competition benefits.

While both approaches are acceptable to the AER, EY recommends applying the Frontier approach in the competition benefits modelling for the ISP for the following reasons:

- The Frontier approach assesses the competition benefits over and above the traditional benefits which ensures that the total gross market benefits, particularly efficiency savings already calculated in the competitive bidding paradigm, are not double counted; and
- The Frontier approach has been used in past studies, including:
  - for the SNOVIC upgrade[16] which outlines the details of modelling considerations for calculating competition benefits in the NEM;
  - for the recent study on the Liddell closure[17] (although for a different purpose) which provides reasonable background and up-to-date information about the modelling and particularly the strategic players and historical analysis of major coal generator bidding strategies; and
  - for the recent HumeLink PACR modelling.

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[15] Under clause 5.22.10(c)(3) of the NER, AEMO must take all the classes of market benefits as material unless it can provide reasons why: • a particular class of market benefit is likely not to materially affect the outcome of the assessment of the development path; or • the estimated cost of undertaking the analysis to quantify the market benefit is likely to be disproportionate given the level of uncertainty regarding future outcomes.

[16] Frontier Economics, September 2004, *Evaluating interconnection competition benefits*. Available at: https://www.aer.gov.au/system/files/Frontier%20Economics%20report%20-%20evaluating%20interconnection%20competition%20benefits%20-%20September%202004.pdf. Accessed 7 October 2021.

[17] Frontier Economics, *Modelling of Liddell power station closure*. Available at: https://www.energy.gov.au/sites/default/files/Frontier%20Economics%20Modelling%20of%20Liddell%20Power%20Station%20Closure.pdf. Accessed 7 October 2021.

Figure 3 illustrates a high-level overview of the Frontier approach.

Figure 3: Overview of the Frontier approach

1. Determine the likely dispatch pattern for hydro and participants' contract cover
   - Model the efficient operation of generators to satisfy demand
2. Analyse the likely market outcomes given participants' market power
   - Determine equilibrium bidding patterns with and without network augmentation
3. Use the outcomes from Stage 2 to calculate the competition benefits
   - Compare the total surplus under the post-augmentation equilibrium versus the pre-augmentation equilibrium

A detailed description of the Frontier approach and how it may be applied to evaluating competition benefits within the ISP framework is provided in the following section.

3.1 Competition benefits methodology

3.1.1 Frontier definition

The Frontier approach involves finding the difference between the change in overall economic surplus resulting from the CDP[9]:

- assuming bidding reflected the prevailing degree of market power both before and after the CDP ; and
- assuming fully competitive bidding both before and after the CDP.

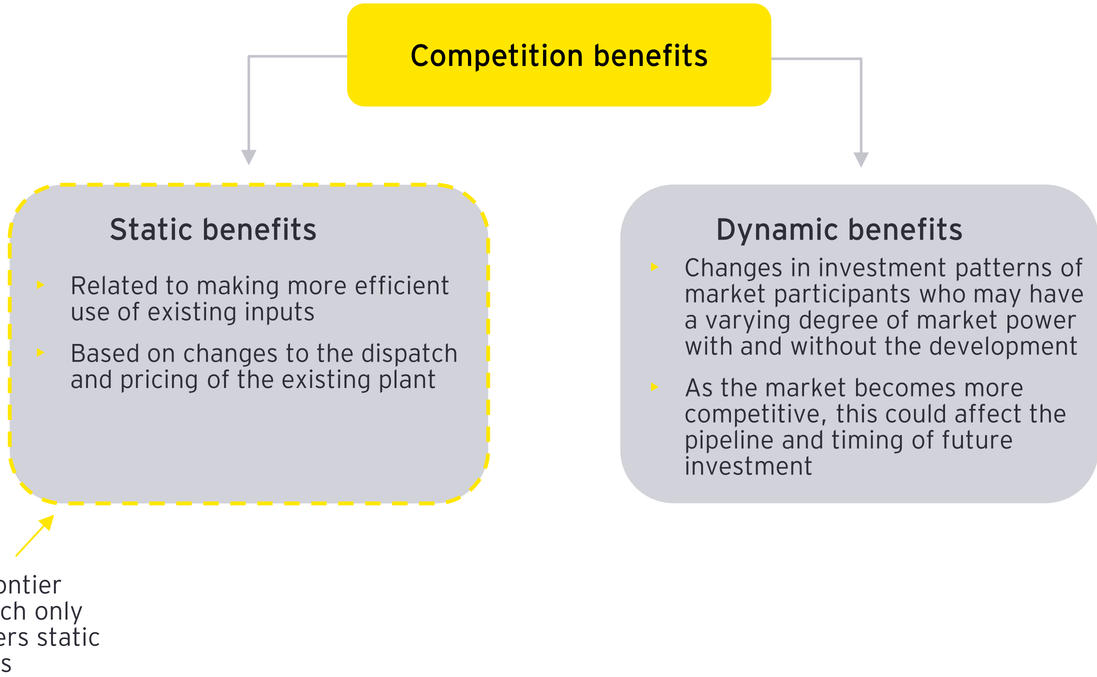
The importance of competition benefits was highlighted by Frontier Economics back in 2004 as follows[16]:

- *"the original intent of the NEM was to develop arrangements to facilitate the development of (regulated) interconnects to promote competition between the State electricity systems and yet, to-date, the competitive impacts from interconnection have been ignored; and*
- *as the power system evolves with the connection of new generators and loads in response to the price signals given by the market, the contribution of the other (non-competition related) benefits to the overall benefits of interconnection will diminish. This will mean that competition benefits will become an increasingly important source of the benefits of interconnection. Therefore, more time and effort will need to be spent in understanding the nature of these benefits and how they can be measured."*

The Frontier approach has stated that competition benefits can be grouped into "static benefits" and "dynamic benefits". The static benefits relate to making more efficient use of existing input, which are based on the changes to the dispatch and pricing of existing plant. These benefits are different to the dynamic benefits which consider the changes in investment patterns such as avoiding generators (or proponents) with a degree of market power investing in new capacity earlier than an independent investor, in order to entrench its market position. These dynamic competition benefits are in addition to the dynamic market benefits itemised in Figure 2 under traditional benefits such as the differences in the timing of capital expenditure.

The reason for (only) modelling the static competition benefits is to remove the need for the complexity of calculating the competition related dynamic benefits, as outlined by Frontier Economics, unless there is a sufficient justification for undertaking further complex analysis beyond that of the static competition benefit analysis. The Frontier approach states that if the static competition benefits are not significant, it is likely that the dynamic competition benefits are also small, and therefore the significant effort required to undertake the complex modelling would outweigh the benefits.

Figure 4: Static and dynamic competition benefits



The Frontier approach for defining competition benefits is to measure the additional benefits that an augmentation might accrue if the assumption of fully competitive bidding was relaxed[16]. These benefits are over and above traditional market benefits, and are expected to flow from taking into account "realistic bidding"[18] behaviour of generation portfolios.

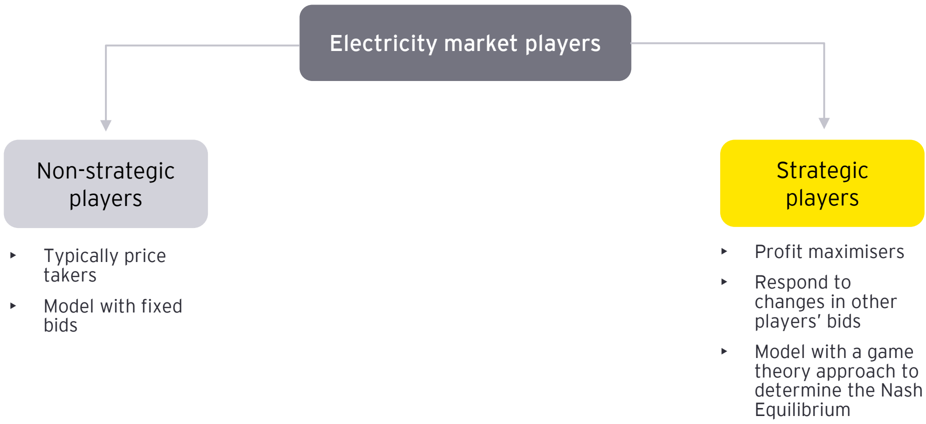
3.1.2 Strategic bidding and Nash Equilibrium

Calculating competition benefits requires a robust approach to determining realistic bidding. The AER suggest that it should be based on a credible theory as to how participants are likely to behave in the market over the modelling period, while taking into account the interaction of participants in their bidding behaviour[9].

Electricity market players can be generally classified as non-strategic or strategic players (see Figure 5). Non-strategic players are typically price takers and can be modelled with fixed bids. In contrast, strategic players are those players that submit bids to maximise their profit when possible, taking into account the changes (if any) to bidding seen from other players.

[18] As described in the AERs August 2020, *Application guidelines - Regulatory investment test for transmission*.

Figure 5: Non-strategic and Strategic players



Game theory is a branch of mathematical analysis which is designed to examine decision making when the actions (such as bids) of one decision maker (player) affect the outcomes of other players. These actions may elicit a competitive response that alters the first player's outcome[17]. Game theory is a robust and methodical approach, and one of its model outputs is a Nash Equilibrium. In the context of the NEM:

- The Nash Equilibrium identifies a set of generator and dispatchable load bids/offers which rational participants would choose under a given set of market conditions[16].
- The Nash Equilibrium outcome is found when the best responses of all players coincide[16] – in other words, all strategic players maximise their profit from a particular selected combination of bids/offers.

A wide range of bids can be used for a game theory approach to the NEM. This includes capacity bids (Cournot modelling, shifting capacity between price bands, typically moving/withholding capacity from low price to higher price bands), price bids (Bertrand modelling (shadow pricing), modifying price bands whilst retaining capacity at each band), or a combination of both[17]. There are countless possible combinations and it is not possible, nor useful, to attempt to find the theoretically perfect combination of all potential bids[16] for all potential players. There are several reasons for this:

- It is likely that only larger generators and portfolios will attempt to influence market prices by changing their bids or withholding some level of capacity to higher price bands.
- Generators which can influence transmission network constraints – particularly constraints which impact interconnector flows – are likely to have some market power.
- Strategic bidding depends on other factors such as the available capacity in the market.
  - If there is additional spare capacity available in the market – for example, during daytime periods due to the increased rooftop PV generation that reduces grid demand – strategic players' bidding actions will be less impactful.
- The contract levels of generators capture their impact on marginal bidding decisions[17].

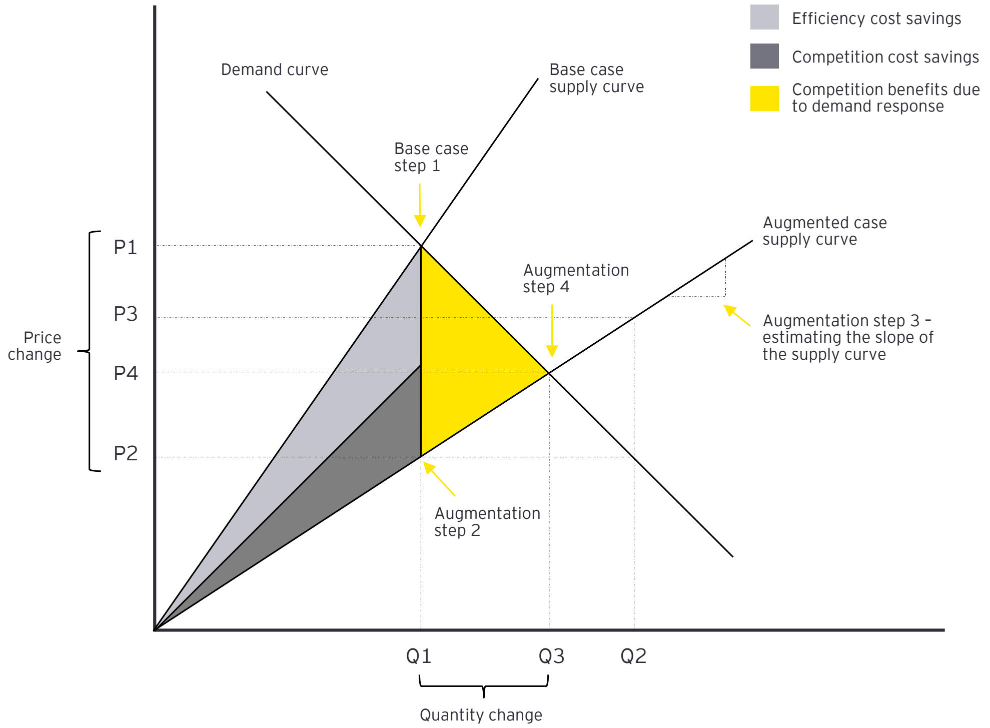
Conventional storage hydro generators as well as large pumped hydros can also play strategically in the market. Modelling storage hydros and pumped hydros strategically is complex, as their dispatch depends on several factors such as storage capacity, inflow and availability. The Frontier approach assumes hydro generators and storages are non-strategic players, while stating that this assumption would tend to underestimate the value of competition benefits[16].

3.1.3 Competition benefits calculations

Static competition benefits accrue from competition cost savings as well as benefits due to elasticity of demand to electricity price, which is described by Frontier Economics as demand response. As seen in Figure 6, the Frontier approach identifies three areas of static benefits associated with a new or upgraded interconnection, called[16]:

- **efficiency cost savings** – due to more efficient dispatch in the SRMC bidding paradigm, which reflects fully competitive bidding without any player choosing to bid strategically. These are the traditional static benefits.
- **competition cost savings** – enhanced efficiency cost savings due to creating an increased level of competition associated with the expanded transmission capacity, and less possibility for strategic players to exert market power.
- **competition benefits due to a demand increase** – response to lower electricity market prices, resulting in an increase in the level of aggregate supply and demand, which is due to elasticity of demand to wholesale market price. Augmentations might lead to sustained lower prices at least in the importing region, which would encourage more consumption by consumers. This is considered as a competition benefit component as it will add to the total surplus of generators and consumers[19]. This applies even with a shift towards higher levels of renewable generation, where the expanded transmission provides better access to lower cost renewable generation and reduced congestion.

Figure 6: Calculation of competition benefits[5]



Gross competition benefits are calculated as the difference between the total surplus of the augmentation equilibrium and the base case equilibrium.

Figure 6, in combination with the diagram below (Figure 7) illustrates the steps taken to calculate both competition cost savings and competition benefits due to demand response. While the detail of

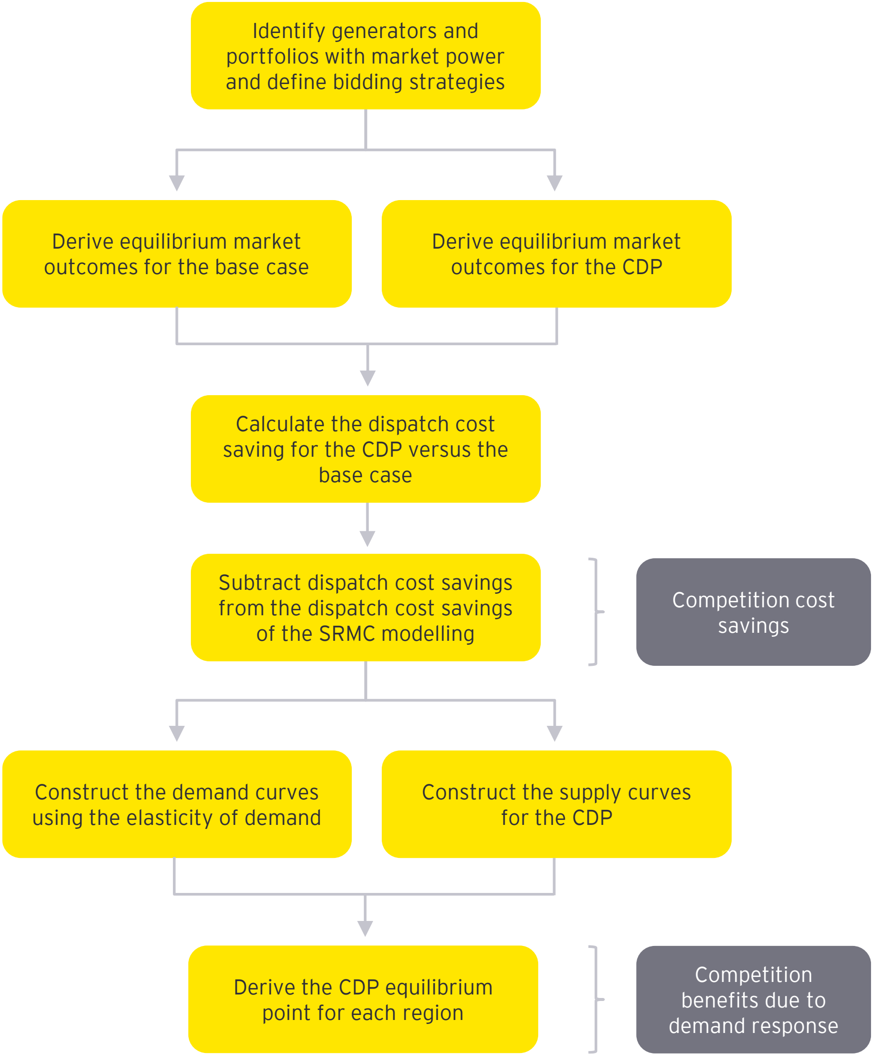
[19] It is important to note that this does not equate to attributing a wealth transfer between producers and consumers to competition benefits, which is explicitly excluded from market benefit calculations by the AER in their August 2020 Application guidelines - Regulatory investment test for transmission and also their August 2020 Cost benefit analysis guidelines.

these steps is provided in Appendix A, here we provide a high-level overview of the steps. For assessment of competition benefits for the ISP, a CDP rather than an individual network augmentation may be assessed for the potential for competition benefits to be material, but the general principles still apply.

First, the list of strategic players is identified and their bidding combinations established, as explained in Section 3.1.2 and a case study presented in 3.2.1 which could also be generalised/modified to be adopted in the ISP modelling . Having established the reasonably likely combinations of bids, the equilibrium outcomes including the demand-weighted prices for each region can be derived for both the base case (the counterfactual case) and the CDP (P_1 and P_2 in Figure 6). Once the dispatch cost savings from the CDP are calculated under strategic bidding, it is possible to derive the competition cost savings. This is done by subtracting the dispatch costs savings from the CDP already calculated in the competitive bidding model (efficiency cost savings in Figure 6) from the dispatch cost savings from the CDP under strategic bidding.

The abovementioned steps in driving the equilibrium point for the CDP case do not yet consider the elasticity of demand to wholesale market prices. When considering the elasticity of demand to wholesale market price, the equilibrium point will be different, which is able to be captured in the competition benefits calculation. To this end, it is proposed to calculate the competition benefits due to an increase in the aggregate level of supply and demand, to the point where the incremental cost of production matches the incremental customer willingness to pay. For this, both supply and demand curves are required to be constructed, as detailed in Appendix A. This helps determining the equilibrium point for the CDP with the consideration of elasticity of the demand to a sustained change in wholesale market price, and therefore to calculate the competition benefits due to demand response, as shown in the yellow area in Figure 6.

Figure 7: Steps in calculating competition benefits



3.2 Case study: HumeLink PACR competition benefits modelling

EY has modelled competition benefits for HumeLink in the PACR[20]. EY used the Time Sequential Integrated Resource Planner (TSIRP) for the calculation of traditional benefits, and adjusted it to compute competition benefits. The TSIRP was adjusted to use the capacity build and retirements schedule which resulted from the long-term investment planning from the base case[21], which allows modelling economic dispatch to determine variable and fuel costs. EY has modelled hydro and energy-limited storages in such a way that they are optimised in the model so that they maximise their water values, corresponding with minimising the total cost of dispatch.

The model was run on both the base case and HumeLink for two sets of bidding, i.e. competitive (SRMC) and strategic bidding. The modelling of competitive bidding allows subtracting the benefits of fuel and variable, operation and maintenance cost (VOM) from the total benefits in the strategic bidding modelling. This avoids the risk of double counting these benefits. In all four runs (with and without HumeLink, with and without strategic bidding), the same capacity expansion plan for new generation, storage and other transmission was assumed, and the same retirement schedule was applied.

[20] TransGrid, *HumeLink PACR* , https://www.transgrid.com.au/projects-innovation/humelink, Accessed 7 October 2021.
[21] Refer to the HumeLink PACR, TransGrid, *HumeLink PACR* , https://www.transgrid.com.au/projects-innovation/humelink, Accessed 7 October 2021.

Figure 8: Steps in EY calculations of RIT-T benefits, including competition benefits

1. **TSIRP modelling, long-term (25 years) optimisation using SRMC bids**
   - Determine the generation development plan and retirement schedule
   - Calculate the traditional benefits

2. **Model setup for competition benefits**
   - Fix the generation development plan and retirement schedule in the base case and use it for both the base case and HumeLink
   - Adjust TSIRP accordingly so only variable costs are considered in the calculations

3. **Model competition benefits, following the steps in Figure 7**
   - Calculate competition cost savings
   - Calculate competition benefits due to demand response

3.2.1 Strategic bidding selection

The strategic players and their bidding strategies were selected such that, while all the relevant combinations of bids are modelled, the modelling is practical and computationally feasible. One approach to limit the number of strategic players is to select only the largest generation portfolios in each region and across the NEM.

Frontier Economics has conducted a study for the Liddell closure in 2019[17], in which a detailed study of historical bidding analysis of generators in the NEM, particularly coal generators for the period of up to 10 historical years is presented. From that study, a list of strategic players and their bidding strategies as well as the general observed behaviour over a six-year historical periods is provided. The observed behaviours range from offering SRMC only up to minimum load (~40% capacity at SRMC and 60% withdrawn to high price) through to offering 95% at SRMC.

Table 1: Bidding strategies in Frontier modelling for Liddell closure[17]

Portfolio	Generators	Strategy options (proportion of capacity offered at SRMC)	Historical analysis
AGL NSW	Bayswater, Liddell	40%, 70%, 80%	50-60% Liddell 70-80% Bayswater
AGL Vic	Loy Yang A	80%, 95%	90-95%
EA NSW	Mt Piper	40%, 75%, 80%	50-85%
EA Vic	Yallourn	80%, 95%	75-95%
Stanwell QLD	Stanwell, Tarong, Tarong North	40%, 70%, 90%	70-80% Stanwell 40-85% Tarong 50-85% Tarong North
CS QLD	Callide B, Callide C, Gladstone, Kogan	40%, 70%, 90%	55-95% Callide B & C 40-70% Gladstone 80-100% Kogan
Origin NSW	Eraring	70%, 85%	50-75%
EA Vic	Yallourn	80%, 95%	75-95%

In the HumeLink PACR competition benefits, EY used this recent analysis conducted by Frontier Economics[17]. However, a shorter list of strategic players was considered given that, with the assumption of economic retirements in the HumeLink PACR market modelling, some generators in the Frontier Economics list, including the Liddell plant which is the subject of the Frontier report, either retire earlier than the proposed HumeLink commissioning date, or within a short time after that. Those generators are therefore modelled to continue bidding at SRMC levels consistent with a fully competitive market until they exit the market before or shortly after HumeLink is commissioned. Table 2 provides the list of generators adopting strategic bidding in the modelling undertaken for the PACR. The full combinations of the following bidding strategies are then modelled to determine the Nash Equilibrium. The Nash equilibrium is determined to be one of the 54 combinations that applies for the full outlook period. That is, the Nash equilibrium has not been investigated for each hour independently, or for each year independently. Deriving the equilibrium from all bid combinations for each half-hourly (or hourly) interval for a 25-year study period is computationally expensive and this is therefore not proposed. The Nash equilibrium is identified as the combination of strategic bids which results in a profit maximising equilibrium of each portfolio over the study period.

EY also assumed the generators withdraw their respective capacity to a price of $500/MWh instead of the assumption of withholding the capacity altogether (which can lead to unserved energy events), or to the market price cap (which is more aggressive and would result in higher competition benefits but potentially stimulate additional investment). $500/MWh was the level that Frontier Economics identified as a break point between cost-based bidding and defence of caps and the higher values adopted for strategic bidding[17].

Table 2: Bidding strategies in HumeLink PACR

Portfolio	Generators	Strategy options
AGL NSW	Bayswater	40%, 70%, 80%
AGL Vic	Loy Yang A	80%, 95%
EA NSW	Mt Piper	40%, 75%, 80%
Stanwell QLD	Stanwell, Tarong	40%, 70%, 90%

The remaining generators are assumed to be non-strategic. Note that it is assumed that non-strategic players bid their full capacity at their short-run marginal cost of supply (SRMC).

EY also modelled battery energy storage facilities, conventional storage hydro and pumped storage hydro generators including Tumut and Snowy 2.0 on a competitive bidding basis. For these generators the cost of water with a fixed supply is an opportunity cost that depends on prices in the market, leading them to generally maximise their output during high prices. Therefore, it is less likely that these generators withhold their capacity similar to the way strategic coal players do to increase prices. In addition, according to the Frontier Economics assessment, modelling hydro generators on a competitive bidding basis is likely to result in underestimating the competition benefits and as such modelling these generators on a strategic basis is expected to add unnecessary complexity to the modelling

The selection of strategic players recognises that there are some key constraints including the network limits between Snowy and the greater Sydney area, including Bannaby to Sydney, which could encourage portfolios with generators on either side of this constraint to play strategically in order to increase the NSW price. In some situations there may be an incentive for a generation portfolio to increase the output at its plant upstream of the transmission limit in order to cause the market constraint to bind, enabling its generating plant near to the reference node to benefit from transient market power[22]. In other situations, where a network augmentation is entirely within a single region, such incentives may not exist as all generators within a region receive the same price.

Limiting the complexity of the modelling problem (such as through selecting only a sub-set of strategic players) is reasonable where the simplification is expected to underestimate value associated with competition benefits, rather than potentially overstating.

3.2.2 Selection of generation development plan

The EY competition benefits modelling used the base case generation development plan, as per the "static benefits" defined by Frontier approach. The appropriateness of this approach for ISP assessment of competition benefits is a matter for this consultation.

The modelling of traditional benefits, including all aspects outlined in Figure 2, is normally conducted as a single optimisation, as the ISP does since all benefits are computed using the same suite of models. All aspects of traditional benefits, both savings due to reduced production costs, and savings due to reduced capital investment costs, are integrated. This includes making trade-offs between building higher capital cost, more efficient plant such as CCGTs versus lower capital cost, less efficient plant such as OCGTs.

It also includes making trade-offs between zero fuel cost variable renewable energy (VRE) generation, and alternatives such as batteries and pumped storage hydro which can reduce the build of VRE plant but must pay the cost of cycling inefficiency from storing and releasing the generation. This optimisation approach necessarily assumes all generators bid SRMC and storage behave in order to minimise the total cost of energy over the forecast horizon. At this time, it is not computationally feasible to enable strategic bidding for all generators and portfolios while still finding the optimum as this is fundamentally a non-linear problem and therefore not able to be solved in a single linear programming optimisation.

In order to configure the model to simulate marginal wholesale pool prices, capital decisions must be removed from the optimisation problem for the purpose of competition benefits assessment. As such, a 'fixed' generation and storage development/retirement plan was established and capital investment options were not available. Static competition benefits are short term by nature as they are chosen by the players in the market every 5-minute dispatch interval, so the assumption of a fixed generation development plan was considered by EY to be appropriate.

Furthermore, for determining static competition benefits the primary difference between the base case and the augmentation case is the presence or absence of the network augmentation that is being assessed. Following this logic, EY considers that any resulting changes in the development pattern of generation due to the presence or absence of the network augmentation were unlikely to impact the static competition benefits.

The main changes due to the augmentation are capital deferral and shifting of renewable generation to more optimal locations. Neither new entries nor renewable generation are modelled strategic players, so for this case study, it was assumed that the residual demand to be met by the strategic players (and the bidding outcomes) were therefore broadly similar. Further, it was assumed that the long-term impact of the augmentation on wholesale price (and corresponding competition benefits associated with demand response) would be similar, regardless of whether the base case generation development plan or a generation development plan with some capital deferral was considered in the presence of the augmentation.

[22] Darryl Biggar, "THE THEORY AND PRACTICE OF THE EXERCISE OF MARKET POWER IN THE AUSTRALIAN NEM", https://www.aemc.gov.au/sites/default/files/content/1b0947b4-930f-449a-be21-4cf009b2fe7a/AER-Attachment-1.PDF Accessed 7 October 2021.

3.2.3 Selection of time periods

It is expected that when there is more spare supply side capacity in the market, the capability of strategic players to change their bids or withhold their capacity to raise prices is low. For example, with significant rooftop PV and large-scale solar, it is unlikely that strategic players could exert market power during sunlight hours. The bidding strategies are therefore applied only during the typical peak demand periods between 6am-10am and 6pm-10pm, when portfolios with market power are expected to bid strategically. EY has also modelled competition benefits for all periods in the modelling study and found the results are not significantly different

3.2.4 Elasticity of the demand to wholesale price

Elasticity of demand is the ratio between proportional change in quantity demanded and proportional change in price[23]. Elasticity of demand is an important factor in the calculation of competition benefits. As shown in Figure 9, apart from the electricity price differences between the base case and augmentation case, area F is also influenced by the elasticity of demand. That is, if the demand is highly responsive to the price changes, the slope of the demand curve is lower and thus the competition benefits due to demand response is higher and vice versa.

There are various documents stating the elasticity of demand to electricity price in the regions comprising the NEM. The elasticity of demand values are generally estimated relative to residential or retail electricity price. For example, the TransGrid 2021 Transmission Annual Planning Report (TAPR) has a range of elasticity of demand between -0.08 and -0.84 for different consumer sectors[24]. In a review of studies about the NEM elasticity of demand, a range of -0.08 to -0.55 is listed for various demand sectors in the NEM[25]. AEMO Input, Assumptions and Scenarios Report (IASR) provides elasticity of demand for different types of consumers, with a typical value of -0.1, but ranging between -0.05 and -0.15 for different use types and scenarios[26].

For the ISP competition benefits calculation, an elasticity of -0.1 for all regions is considered to be a conservative, that is, reasonably low value for the elasticity of demand from the range identified. Competition benefits modelling is applied at the wholesale level whereas elasticity of demand is relative to retail electricity price. As such it is appropriate to apply a conversion factor to the elasticity of demand to retail price value. This conversion factor could carefully consider the impact of the cost of the proposed network augmentation on the relative proportion of retail electricity prices attributable to wholesale electricity price. For example, for the HumeLink assessment, the conservative elasticity value of -0.1 proposed by TransGrid was further halved to -0.05 in this regard.

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[23] Oxford Reference, https://www.oxfordreference.com/view/10.1093/oi/authority.20110803095745343, Accessed 7 October 2021.

[24] TransGrid, 2021 TAPR, https://www.transgrid.com.au/media/jtabhxws/transmission-annual-planning-report-2011.pdf, Accessed 7 October 2021.

[25] Centre for Climate Economic & Policy, Australian National University, Impact of the carbon price on Australia's electricity demand, supply and emissions, https://www.lse.ac.uk/GranthamInstitute/wp-content/uploads/2014/08/OGorman-and-Jotzo-Impact-of-the-carbon-price-on-Australias-electricity-demand-supply-and-emissions.pdf, Accessed 7 October 2021.

[26] AEMO, 2021 2021 Inputs, Assumptions and Scenarios Report, https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf?la=en, Accessed 7 October 2021.

Appendix A Calculation of competition benefits

As per the Frontier approach[16], the following steps have been undertaken to calculate competition benefits:

- Step 1: Equilibrium market outcomes are derived for the counterfactual Base case. This determines the optimal bidding strategy of the strategic players, which results in equilibria with the annual average demand weighted price in the Base case ($P1$ in Figure 9 for the annual demand $Q1$.
- Step 2: Step 1 is repeated for the augmentation case with an assumption that the demand is inelastic. This allows calculation of $P2$. However, this point does not necessarily represent the augmentation equilibrium as the elasticity of the demand is ignored. To consider the impact of demand elasticity, the following steps are required to be taken.
- Step 3: This step estimates the slope of the augmented case supply curves in each region. For this purpose, a small change in each region's demand is applied and the resulting prices ($P_{3,r,c}$) in that region and other regions are calculated. Calculating $P_{3,r,c}$, which is the demand weighted price of region r due to small change in demand in region c, allows the construction of an inverse cross-elasticity of supply matrix, as discussed in Step 4.
- Step 4: The inverse cross-elasticity of supply matrix is constructed by using the relationships between relative demand changes to relative price changes in each region. The elements of the inverse cross-elasticity of supply matrix, S, are constructed as follows:

$$element\ (r,c) = \frac{\frac{P_{3,r,c} - P_{2,r}}{P_{1,r}}}{\Delta Q_{3,c}}$$

where, $element\ (r,c)$ is the matrix element in row/region r, column/region c, and $P_{1,r}$ and $P_{2,r}$ are the demand weighted price in region r from Step 1 and Step 2, respectively. $P_{3,r,c}$ is the demand weighted price in region r for a small change in demand in region c. $\Delta Q_{3,c}$ is the relative demand change in region c.

In addition, the regional demand curves are determined by cross-elasticity of demand matrix, matrix D, which is 5×5 matrix (to represent the five NEM regions) with the diagonal elements being the inverse of the regional demand elasticities and other elements being zero.

Having the inverse cross-elasticity of supply and also inverse cross elasticity of demand matrices, a linear approximation of supply and demand curves can be derived and accordingly, the intersection of the two curves in Figure 9 can be calculated. The intersection is at Q_3 and P_4, the augmentation equilibrium point.

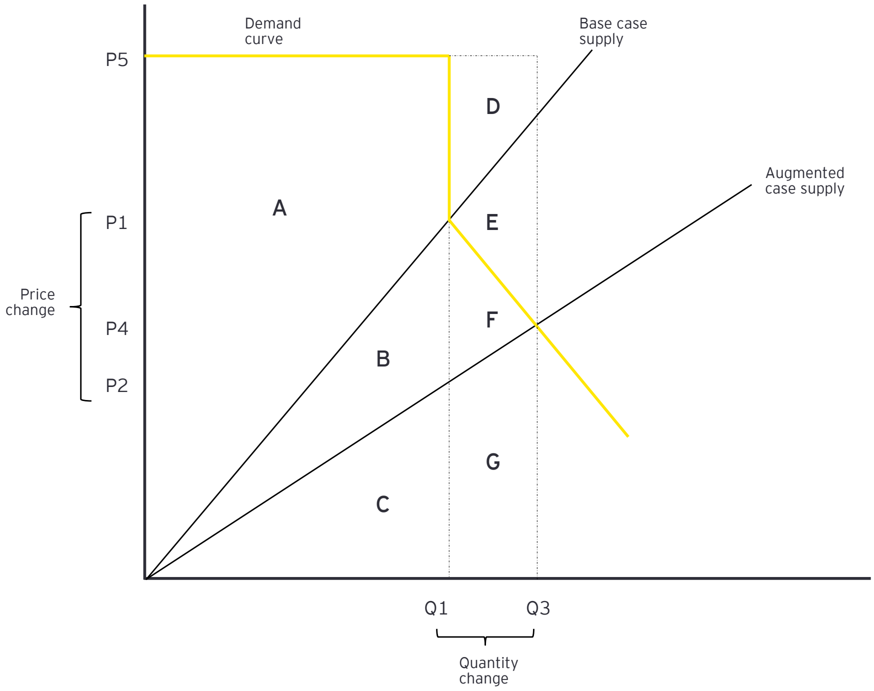
This also enables estimating the production cost at the equilibrium point, which is calculated as the average incremental production costs of each region by constructing the production cost matrix as follows:

$$element\ (1,c) = \frac{PC_{3,c} - PC_2}{\Delta Q_{3,c}}$$

where, $element\ (1,c)$ is the matrix element for column/region c, and PC_2 is the total production cost in Step 2. $PC_{3,c}$ is the total production cost in Step 3 for a small change in demand in region c. $\Delta Q_{3,c}$ is the relative demand change in region c. As such, the relative increase in production costs from Step 2 to the post-augmentation equilibrium can be calculated as Cq, where q is the quantity change of the post-augmentation equilibrium for each region relative to the pre-augmentation equilibrium.

- Step 5: Having the intersection of supply and demand curves, as well as the production costs, the gross benefits can be calculated by subtracting the total surplus of Base case equilibrium from augmentation equilibrium, resulting in areas B and F in Figure 9. While area F represents competition benefits due to demand response, area B represents the aggregated productive efficiency of the augmentation due to efficiency and competition cost savings. In order to calculate purely competition cost savings and avoid double counting the efficiency cost savings which is calculated as part of traditional market benefits in the competitive (SRMC) modelling, the benefits from the efficiency cost savings are subtracted from the total benefits.

Figure 9: calculation of surplus[16]



Glossary of terms

Abbreviation	Meaning
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CAPEX	Capital Expenditure
CCGT	Combine Cycle Gas Turbine
CDP	Candidate Development Path
EA	Energy Australia
EY	Ernst & Young
FOM	Fixed Operation and Maintenance
ISP	Integrated System Plan
NCEN	Central NSW
NEM	National Electricity Market
NER	National Energy Rules
NSW	New South Wales
OCGT	Open Cycle Gas Turbine
ODP	Optimal Development Path
PACR	Project Assessment Conclusion Report
QLD	Queensland
RIT-T	Regulatory Investment Test for Transmission
SRMC	Short-Run Marginal Cost
TAPR	Transmission Annual Planning Report
TSIRP	Time-sequential integrated resource planner
USE	Unserved Energy
Vic	Victoria
VNI	Victoria-NSW Interconnector
VOM	Variable Operation and Maintenance
VRE	Variable Renewable Energy

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