Draft

Regulatory investment test for transmission application guidelines

March 2010

AUSTRALIAN ENERGY REGULATOR

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Amendment record

Version	Date	Pages
01 (draft)	March 2010	72

Contents

Shortened forms

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AEU	Australian Emissions Unit
CPRS	carbon pollution reduction scheme
Electricity Rules	National Electricity Rules
MW	megawatt
MWh	megawatt hour
NEM	National Electricity Market
REC	renewable energy certificate
RET	renewable energy target
RIT-T	regulatory investment test for transmission
SRMC	short-run marginal cost
TNSP	transmission network service provider

1 Nature and authority

1.1 Introduction

Consistent with the requirements of clause 5.6.5B of the National Electricity Rules (the Electricity Rules), this publication provides guidance on the operation and application of the *regulatory investment test for transmission* (the RIT-T).

1.2 Authority

Clause 5.6.5B of the Electricity Rules requires the Australian Energy Regulator (AER) to publish guidelines for the operation and application of the RIT-T (the application guidelines). The application guidelines must:

- give effect to and be consistent with the relevant provisions of the Electricity Rules
- provide guidance on:
  - the operation and application of the RIT-T
  - the process to be followed in applying the RIT-T, and
  - how disputes regarding the RIT-T and its application will be addressed and resolved
- provide guidance and worked examples as to:
  - what constitutes a *credible option*
  - acceptable methodologies for valuing the costs of a *credible option*
  - what may constitute an externality under the RIT-T
  - the classes of market benefits to be considered
  - the suitable modelling periods and approaches to scenario development
  - acceptable methodologies for valuing the *market benefits* of a *credible option*
  - the appropriate approach to undertaking sensitivity analysis
  - the appropriate approaches to assessing uncertainty and risks, and
  - when a person is sufficiently committed to be characterised as a proponent.

1.3 Role of this application guideline

Transmission network service providers (TNSPs) must apply the RIT-T to all proposed *transmission investment* except in the circumstances described in clause 5.6.5C of the Electricity Rules. These application guidelines provide guidance on the operation and application of the RIT-T, the process to be followed in applying the RIT-T, and how disputes regarding the RIT-T will be addressed and resolved.

These guidelines should be **read in conjunction** with the requirements in the RIT-T and clauses 5.6.5A, 5.6.5B, 5.6.5C, 5.6.5D, 5.6.6 and 5.6.6A of the Electricity Rules.

1.4 Definitions and interpretation

In these application guidelines the words and phrases in italics have the meaning given to them in:

- the glossary, or
- if not defined in the glossary, the Electricity Rules.

1.5 Process for revision

The AER may amend or replace these guidelines from time to time in accordance with the *transmission consultation procedures* and clause 5.6.5B of the Electricity Rules.

1.6 Version history and effective date

A version number and an effective date of issue will identify every version of these guidelines.

2 Overview of the RIT-T

Under clause 5.6.5B of the Electricity Rules the AER is required to publish the RIT-T and application guidelines. The RIT-T is an economic cost benefit analysis which is used to assess and rank different electricity investment options.

From 1 August 2010, TNSPs must apply the RIT-T in accordance with clause 5.6.6 of the Electricity Rules to assess the economic efficiency of proposed investment options. The RIT-T is intended to promote efficient transmission investment in the *national electricity market* (the NEM) and ensure greater consistency, transparency and predictability in transmission investment decision making. The RIT-T replaces the AER's *regulatory test* for transmission investment.

2.1 Purpose of the RIT-T

Clause 5.6.5B of the Electricity Rules states that the purpose of the RIT-T is to:

> … identify the *credible option* that maximises the present value of net economic benefit to all those who produce consume and transport electricity in the *market* (the *preferred option*). For the avoidance of doubt, a *preferred option* may, in the relevant circumstances, have a negative *net economic benefit* (that is a net economic cost) where the *identified need* is for *reliability corrective action*.

2.2 Investments subject to RIT-T assessment

Clause 5.6.5C of the Electricity Rules provides that a TNSP must apply the RIT-T to all proposed *transmission investments* unless the investment falls under defined circumstances.

A *transmission investment* is defined in the Electricity Rules as:

> Expenditure on assets and services which is undertaken by a *transmission network service provider* or any other person to address an *identified need* in respect of its *transmission network*

The circumstances where a TNSP does not need to apply the RIT-T include where:

- a proposed investment is required to address an urgent and unforeseen *network* issue (discussed below)
- the estimated capital cost of the most expensive option to address the *identified need* is less than $5 million (the AER must review this threshold every three years)[1]
- the proposed investment relates to maintenance or replacement and is not intended to *augment* the *transmission network*. If the maintenance or replacement results in an *augmentation* of the *transmission network*, the *augmentation* component is

[1] Under clause 5.6.5E of the National Electricity Rules the AER must review RIT-T cost thresholds every three years with the first review to commence in 2012. Details regarding any review of the RIT-T thresholds (including any revisions to this threshold) will be published on the AER's website www.aer.gov.au.

exempt if the estimated capital cost of the *augmentation* is less than $5 million (the AER must review this threshold every three years)[2]

- the proposed investment is undertaken to re-route one or more paths of the *network* and has a substantial primary purpose other than the need to augment the *network*. The TNSP must reasonably estimate that the investment will cost less than $5 million (the AER must review this threshold every three years)[3] or is likely to have no material impact on network users

- the proposed investment will be a *dual function asset* or a *connection asset*[4]

- the proposed investment is designed to address limitations on a *distribution network*

- the cost of the proposed *transmission investment* is to be fully recovered through charges for *negotiated transmission services*.

In determining whether a TNSP must apply the RIT-T to a proposed transmission investment, a TNSP must not treat different parts of an integrated solution to an *identified need* as distinct and separate options.[5]

Where a TNSP does not need to apply the RIT-T to a proposed investment (with the exception of *funded augmentations*) [6] a TNSP must ensure, acting reasonably, that the investment is planned and developed at least cost over the life of the investment.[7]

Urgent and unforeseen investments

As noted, a TNSP does not need to apply the RIT-T to a proposed *transmission investment* to address an urgent and unforeseen *network* issue that would otherwise put the reliability of the *transmission network* at risk. Under clause 5.6.5C(b) of the Electricity Rules, a proposed *transmission investment* is only subject to this exemption if:

- it is necessary that the proposed investment be operational within six months of the TNSP identifying the need for the investment

- the event or circumstance causing the *identified need* was not reasonably foreseeable and was beyond the control of the TNSP

- a failure to address the *identified need* is likely to materially adversely affect the *reliability* and *secure operating state* of the *transmission network*, and

- it is not a *contingent project*.[8]

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2 For further details see footnote 1.
3 For further details see footnote 1.
4 Dual function asset and connection assets are defined in chapter 10 of the National Electricity Rules.
5 See clause 5.6.5C(e) of the National Electricity Rules.
6 A funded augmentation is a transmission network augmentation for which a TNSP is not entitled to receive a charge under Chapter 6A of the National Electricity Rules.
7 See clause 5.6.5C(d) of the National Electricity Rules.

3 Operation and application of the RIT-T

This part of the application guidelines provides information and worked examples on the operation and application of the RIT-T.

The broad steps involved in applying the RIT-T can be summarised as follows:

(1) Identify a need for the investment (known as the *identified need*) (see section 3.1)

(2) Identify the *base case* and a set of *credible options* to address the *identified need* (see section 3.2)

(3) Identify a set of *reasonable scenarios* that are appropriate to the *credible options* under consideration (see section 3.5)

(4) Quantify the expected *costs* of each *credible option* (see sections 3.3 and 3.6)

(5) Quantify the expected *market benefits* of each *credible option*—calculated over a probability weighted range of *reasonable scenarios* (see sections 3.4–3.6)

(6) Quantify the expected *net economic benefit* of each *credible option* and identify the *preferred option* as the *credible option* with the highest expected *net economic benefit* (see section 3.7).

3.1 Identified need

An *identified need* is defined in chapter 10 of the Electricity Rules as the reason why a TNSP proposes that a particular investment be undertaken in respect of its *transmission network*. An *identified need* may consist of:

- meeting any of the service standards linked to the technical requirements of schedule 5.1 of the Electricity Rules or in applicable regulatory instruments, and/or

- an increase in the sum of consumer and producer surplus in the NEM.

An *identified need* is to be expressed as the achievement of a desired objective or end, and not simply the means to achieve a desired objective or end. A description of an *identified need* does not mention or explain a particular method, mechanism or approach to achieving a desired outcome.

For example, where a TNSP has concerns over the levels of reactive power in the vicinity of a terminal station, the *identified need* should be expressed as “enhancing the voltage support in the vicinity of the terminal station” rather than “installing additional capacitor banks at the terminal station”.

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[8] Contingent projects are determined by the AER under clause 6A.8.1(b) as part of a TNSP’s revenue determination.

In describing an *identified need* a TNSP may find it useful to explain what will or may happen if the TNSP fails to take any action.

3.2 Credible options

The requirements for a *credible option* are set out in clause 5.6.5D of the Electricity Rules. This clause provides that a *credible option* is an option (or group of options) that:

- addresses the *identified need*
- is (or are) commercially and technically feasible, and
- can be implemented in sufficient time to meet the *identified need*

Particular aspects of this clause are further discussed below.

Where there is a material degree of uncertainty regarding the future scenarios and the option or options under consideration involve a sunk or irreversible action by the TNSP, there may be value in retaining flexibility to respond to changing market developments or scenarios as they emerge. For example, where a TNSP is uncertain about the future demand for connections from wind generators at a remote connection point, it may be efficient for the TNSP to configure the connection assets in such a way as to allow them to be easily augmented in the future should additional demand for connections at this connection point arise.

The AER considers that a *credible option* may include a decision rule or policy specifying not just an action or decision that will be taken at the present time, but also an action or decision that will be taken in the future, if the appropriate market conditions arise. For example, where future demand growth is uncertain, the following may all be legitimate *credible options*:

- Option (a): fully upgrade a transmission line in the immediate term to accommodate all likely demand growth over the next 15–20 years.
- Option (b): upgrade a transmission line to the minimum extent necessary to cover likely demand growth in the next five years (without any further consideration of the potential for further growth in the future).
- Option (c): upgrade a transmission line to the minimum extent necessary in the immediate term, but allow for sufficient extra space to (perhaps by installing larger towers than necessary) to allow for a relatively low-cost expansion of the network if generation growth materialises in the future.

Further guidance on identifying *credible options* where there is a material degree of uncertainty regarding the future is discussed in section 3.6.

Addressing the identified need

An option (or group of options) addresses an *identified need* under clause 5.6.5D(a)(1) of the Electricity Rules if the TNSP reasonably considers that the option would, if commissioned within a specified time, be highly likely to meet one or more *identified needs*.

Example 1 Identified need (service standard)

Changing patterns of generation investment over recent years has increased the likelihood that service standards concerning voltage will be breached in the next few years.

- The *identified need* in this example is to ensure that voltage standards as outlined in Schedule 5.1 of the Electricity Rules continue to be satisfied.
- An example of a *credible option* to address this *identified need* is the installation of one of more voltage control network elements, such as a static VAR compensator.

Example 2 Identified need (market benefit)

Rapid load growth in a remote area with a limited sized link with the rest of the shared network and costly local generation options indicates that it is likely to be net beneficial to augment the link in the future.

- The *identified need* in this example is an (expected) increase in *net economic benefits* compared to the *base case* – that is, the *market benefits* of augmenting the transmission link to this area are likely to outweigh the costs of doing so.
- An example of a *credible option* to address this *identified need* is the augmentation of network element(s) that would increase the capacity of the area's existing link.

Commercially and technically feasible

The AER considers that an option is commercially feasible under clause 5.6.5D(a)(2) of the Electricity Rules if a reasonable and objective operator, acting rationally in accordance with the requirements of the RIT-T, would be prepared to develop or provide the option in isolation of any substitute options.

As set out in clause 5.6.5D(c) of the Electricity Rules, a TNSP is not entitled to reject an option that would otherwise satisfy the RIT-T purely on the basis that the option lacks a proponent or that the TNSP is not willing to be the proponent for the option. Such an option would be commercially feasible because, if undertaken, it would satisfy the RIT-T and therefore provide the investor with a regulated return. The rationale for this requirement is to prevent a TNSP from 'gaming' the RIT-T by only agreeing to act as a proponent for a network option which is over-engineered, more expensive and less net beneficial than other network options. An example is provided below.

The AER considers that an option is technically feasible under clause 5.6.5D(a)(2) of the Electricity Rules if the TNSP reasonably considers that there is a high likelihood that, if developed, the option will provide the services that it is assumed (or claimed on behalf of its proponent) to be able to provide for the purposes of the assessment of that option under the RIT-T, while complying with all mandatory requirements in relevant laws, regulations and administrative requirements. Technical feasibility will always turn on the relevant facts and circumstances, although a brief stylised example is provided below.

Example 3 Commercial feasibility

The most likely option for enhancing the sum of consumer and producer surplus in a particular area is to augment an existing 150 km transmission line between a group of generators and a major load centre.

However, the TNSP refuses to act as a proponent for this option and thereby claims that the option is not a *credible option* for enhancing *net economic benefits*. Instead, the TNSP proposes a more expensive option involving a line following a longer (300 km) route than the existing line.

In this case, the cheaper augmentation must be considered a *credible option*, because a reasonable and objective TNSP would be willing (in isolation of any other substitute projects it might have in mind) to construct it if it passed the RIT-T.

Example 4 Technical feasibility

A proponent has suggested a local geothermal generation option as an alternative to the network option above. According to the proponent, the local geothermal option would provide the same services as the TNSP's network option.

However, the TNSP reasonably believes that the geothermal option will not be feasible at the present time due to the relatively untested nature of the technology in Australia. In this case, the geothermal plant could be excluded from being considered as a *credible option* due to a lack of technical feasibility.

Number and range of credible options

Under clause 5.6.5D(b) of the Electricity Rules, in applying the RIT-T, a TNSP must consider all options that could reasonably be classified as *credible options*, taking into account:

- energy source
- technology
- ownership
- the extent to which the *credible option* enables *intra-regional* or *inter-regional* trading of electricity
- whether it is a *network* or non-*network* option
- whether the *credible option* is intended to be regulated
- whether the *credible option* has a proponent, and
- any other factor which the TNSP reasonably considers should be taken into account.

The absence of a proponent does not exclude a *transmission investment* option from being considered a *credible option*.

The AER is of the view that a TNSP has considered a sufficient number and range of *credible options* where the number of *credible options* being assessed regarding a particular *identified need* is proportionate to the magnitude of the likely *costs* of any *credible option.*

Therefore, if the TNSP reasonably estimates that the *costs* arising from any one of several *credible options* orientated towards meeting an N-1 reliability standard at town X is $50 million, the TNSP should consider a larger number and range of *credible options* than if the estimated *cost* was $10 million.

Criteria for proponents of credible options

The Electricity Rules require the AER to develop guidelines as to when a person is sufficiently committed to a *credible option* for *reliability corrective action* to be characterised as a proponent for the purposes of clause 5.6.5D(b)(7).

The AER considers that a person can be characterised as a proponent of an option where it has identified itself to the TNSP in writing that it is a proponent of an option and has reasonably demonstrated a willingness and potential ability to devote or procure the required human and financial resources to the:

- technical specification and refinement of the option if the TNSP agrees to consider the option as a *credible option* under the RIT-T, and
- development of the option if it is identified as the *preferred option* under the RIT-T. This requires, for example, that the person has expressed a willingness to accept a reasonable network support agreement to develop the *credible option* for a price no higher than one that reasonably reflects the *costs* of the *credible option* applied in the relevant RIT-T assessment.

There may be more than one proponent for a given *credible option*.

3.3 Costs

Costs are defined in the RIT-T as the present value of the direct costs of a *credible option*. The determination of *costs* must include the following classes of costs:

- costs incurred in constructing or providing the *credible option*
- the operating and maintenance costs in respect of the operating life of the *credible option*, and
- the costs of complying with any mandatory requirements in relevant laws, regulations and administrative requirements.

A TNSP must capture these classes of costs in its analysis when applying the RIT-T, however it is not required to **separately** quantify them.

There may be a material degree of uncertainty regarding the *costs* of a *credible option* at the time a TNSP undertakes the RIT-T assessment. Guidance and worked examples on dealing with this uncertainty is included in section 3.6.

The cost of complying with laws and regulations

In some cases, a proponent may have a choice as to how it complies with a law, regulation or administrative requirement. For example the proponent may lawfully choose to pay a financial amount rather than undertake some other action (which is otherwise necessary to comply with the relevant law, regulation or administrative requirement). If the financial amount is smaller than the costs of undertaking some other action the financial amount may be treated as part of the *costs* of such a *credible option*.

However, any harm to the environment or to any party that is not expressly prohibited or penalised under the relevant laws, regulations or administrative requirements does not form part of the *costs* or affect the *market benefits* of the *credible option*.

The limitation of costs in the RIT-T in this manner places the onus on policy makers to explicitly prohibit certain activities or to determine the value to be placed on various types of harm and to impose financial penalties accordingly. It is not the role of the RIT-T to prohibit or penalise certain activities that policy-makers have not themselves determined to prohibit or penalise.

To the extent that market participants in the NEM may be required to pay penalties for failure to comply with a renewable energy target scheme in a particular *state of the world*, this is dealt with in the calculation of *market benefits* of a *credible option*, not the *costs* of the *credible option*.

Example 5 Cost of a credible option (un-priced externality)

To meet an *identified need*, a TNSP identifies as a *credible option* the development of a local gas-fired peaking generator in close proximity to an existing hotel. The present value of the generator's expected construction and operating costs is $120m. The development of the generator is expected to reduce the hotel's earnings due to a loss of visual amenity – the present value of this loss is $5m. There are no planning standards, consents or other requirements which protect the hotel against this loss.

In the absence of any planning standards, consents or other requirements hindering its development, the *costs* of the *credible option* remain $120m. The 'negative externality' created by the generator's development and borne by the hotel is not regulated or legislated by any relevant law, regulation or administrative requirement and hence does not form part of the *costs* of the *credible option*.

Example 6 Cost of a credible option (penalised externality)

Continuing Example 5, assume that a regulatory body allows development of the *credible option* contingent on the developer of the generator paying for landscaping to conceal the generator and reduce the harm to the visual amenity of the hotel's guests. The present value of this landscaping is $5m.

In this case, the *costs* of the *credible option* would be $120m + $5m = $125m. The $5m is now included as part of the *costs* of the *credible option* since a relevant regulatory body decreed that the generator's development was contingent on such an expense being incurred.

3.4 Market benefits

The meaning of *market benefit* and the classes of benefits which must be included when applying the RIT-T are set out in paragraphs 4 and 5 of the RIT-T. Particular aspects of the meaning of and methodology for calculating *market benefit* are expanded in this section of the guidelines and appendix A.

The total benefit of a *credible option* includes the change in:

- consumer surplus, being the difference between what consumers are willing to pay for electricity and the price they are required to pay, and
- producer surplus, being the difference between what electricity producers and transporters are paid for their services and the cost of providing those services (excluding the *costs* of the *credible option*).

The Electricity Rules require that the RIT-T be based on a cost benefit analysis which includes “an assessment of reasonable scenarios of future supply and demand if each *credible option* were implemented compared to the situation where no option is implemented”. For this reason the RIT-T requires a comparison (for each *reasonable scenario*—see below) between:

- a *state of the world* with the *credible option* in place, and
- a *state of the world* in the *base case*.

This comparison may reveal that a *credible option* results in both positive and negative effects on the *market*. The calculation of the *market benefit* of a *credible option* must reflect a netting-off process, whereby both the positive and negative effects of a *credible option* on the NEM across all the relevant classes of *market benefit* are taken into account. This process may result in a *credible option* having a positive or negative *market benefit*.

Appendix A provides guidance and worked examples for each class of *market benefit* referred to in clause 5.6.5D(4) of the Electricity Rules.

Under clause 5.6.5(c)(5) and (6) of the Electricity Rules, a TNSP is required to include all classes of *market benefits* in its analysis when applying the RIT-T that it considers to be material. A TNSP must consider all classes of *market benefit* as material unless:

- it can provide reasons why a particular class of *market benefit* is not likely to materially affect the outcome of the assessment of the *credible options*, or
- the estimated cost of undertaking the analysis to quantify the *market benefit* is likely to be disproportionate to the scale, size and potential benefits of each *credible option* being considered.

3.5 Methodology for calculating market benefits

States of the world and reasonable scenarios

As set out in the RIT-T, the *market benefit* of a *credible option* is obtained by:

(i) comparing, for each relevant *reasonable scenario*:

> (A) the *state of the world* with the *credible option* in place, with
>
> (B) the *state of the world* in the *base case*

(ii) weighting any positive or negative benefit derived in (i) by the probability of each relevant *reasonable scenario* occurring.

A *state of the world* is a detailed description of all of the relevant market supply and demand characteristics and conditions likely to prevail if a *credible option* proceeds or —if the *credible option* does not proceed—in the *base case*. A *state of the world* should be internally consistent in that all aspects of the *state of the world* could reasonably coexist.

Crucially, the pattern of new generation development (incorporating capacity, technology, location and timing) is likely to vary depending on which *credible option* (if any) proceeds. Therefore, each *credible option*—as well as the *base case*—will be associated with a different *state of the world* reflecting different patterns of generation investment and other characteristics and conditions.

Where the *identified need* for a *credible option* is to meet any of the service standards linked to the technical requirements of schedule 5.1 or in applicable regulatory instruments, the *base case* may reflect a *state of the world* in which those service standards are violated. However, this does not alter the need for the use of a certain *state of the world* in which no *credible options* are incorporated to provide a consistent point of comparison across all *credible options* for meeting those mandatory requirements.

As noted above, the calculation of the *market benefit* for a given *credible option* involves a probability-weighting of the benefits arising from that option **across a range of *reasonable scenarios***. That is, two *states of the world* (one with the *credible option* in place and the other being the *base case* with no *credible option* in place) need to be developed in respect of each *reasonable scenario.*

A *reasonable scenario* is a set of variables or parameters that are not expected to change across each of the relevant *credible options* or the *base case*.

For example, the level of economic growth and the associated level of base electricity demand are key components of a *reasonable scenario*. In a particular analysis, it may be appropriate to assess the benefits of a *credible option* across high, medium and low demand *reasonable scenarios*. To the extent that a demand-side option leads to lower peak demand under each of these *reasonable scenarios,* this effect should be accounted for in the *states of the world* associated with that option in each of those *reasonable scenarios*. This ensures that the benefits of the demand-side option are transparently calculated separately in high, medium and low demand scenarios, because such benefits of the demand-side option may vary according to the demand scenario.

Likewise, the unit capital and operating costs of generation plant (in $/MW or $/MWh) should be independent of the *credible option* under consideration. Similarly, the value of any greenhouse or environmental penalties and the value of unserved energy should also be independent of the *credible option* under consideration.

In these guidelines, the term market benefit (not italicised) refers to the incremental benefits of a *credible option* (over the *base case*) **in a given *reasonable scenario***. The term *market benefit* (italicised) refers to the probability-weighted value of the benefits of a *credible option* across the full range of *reasonable scenarios*, with the weighting of the benefits determined by the probability of each *reasonable scenario* occurring.

Notwithstanding the need for probability-weighting of market benefits to derive the *market benefit* of a *credible option*, the AER expects that TNSPs will continue to provide details of the estimated market benefits of a *credible option* under each *reasonable scenario*.

Therefore, the calculation of *market benefit* **for a given *credible option*** involves three key steps:

- **deriving** the *states of the world* with and without the *credible option* in place in each *reasonable scenario*

- **comparing** the relevant *states of the world* with and without the *credible option* in place in each *reasonable scenario* to derive the market benefit of the *credible option* in each *reasonable scenario*, and

- **weighting** the market benefits arising in each *reasonable scenario* by the probability of that *reasonable scenario* occurring.

These steps are discussed further below.

Deriving relevant states of the world

All assets and facilities in existence at the time the RIT-T is applied must, at least initially, form part of all relevant *states of the world* (both with and without the *credible option* in place and in all *reasonable scenarios*).

Beyond taking account of existing assets and facilities, to fully describe a *state of the world*, a TNSP must derive appropriate *committed*, *anticipated* and *modelled projects* — that is the future evolution of and investment in generation, network and load. *Committed*, *anticipated* and *modelled projects* are defined in the RIT-T.

As with existing assets and facilities, *committed projects* have to form part of all *states of the world*.

Anticipated projects should be included in all **relevant** states of the world, based on the reasonable judgment of the TNSP.

The choice of *modelled projects* in a given *state of the world* will need to be determined based on appropriate market development modelling.

Market development modelling involves determining what kind of projects (in particular but not limited to generation projects) would be developed in the longer term both with and without the *credible option* proceeding.

In accordance with paragraph 22 of the RIT-T, market development modelling:

- must be undertaken on a least-cost/central planning-style basis orientated towards minimising the cost of serving load (or allowing load to remain unserved if that is least cost) while meeting minimum reserve levels (least-cost market development modelling), and

- may, where appropriate, be undertaken on a private benefit basis as a sensitivity (market-driven market development modelling).

The reason why least-cost market development modelling must be undertaken is that it relies on relatively uncontroversial assumptions and methodologies (derived from operations research), whereas market-driven market development modelling may be strongly influenced by assumptions regarding plant bidding behaviour and ownership.

By enabling the derivation of *modelled projects* in the presence and absence of a *credible option*, market development modelling assists in determining the market benefits of the *credible option* in a given *reasonable scenario*. For example, market development modelling may assist in determining whether—in high, medium or low *reasonable scenarios*—a network option is likely to lead to the deferral (or advancement) of new generation investment compared to the relevant *base case*. To the extent it does, this would constitute a positive (or negative) contribution to the market benefit of the *credible option*, respectively, in each of those *reasonable scenarios*.

For example, consider a situation where the *identified need* is the meeting of a mandatory service standard and there are two *credible options* that would satisfy that need – a network option and a demand-side response option. This situation would require the derivation of three distinct *states of the world* (and consequently, three *market development scenarios* based on appropriate market development modelling) in respect of each *reasonable scenario*.

Specifically, it would require the derivation of:

- a *base case state of the world* assuming no implementation of either *credible option*

- a network *state of the world* assuming implementation of the network *credible option* only, and

- a demand-side response *state of the world* assuming implementation of the demand-side response *credible option* only,

across all *reasonable scenarios*.

Comparing relevant states of the world

The market benefit of a *credible option* in a given *reasonable scenario* is obtained by comparing the *state of the world* with the option in place with the *base case state of the world*. An explanation of how this is achieved for each class of *market benefit* is outlined below (see Categories of market benefit).

Undertaking the comparison across all reasonable scenarios

The derivation of *states of the world* with and without a *credible option* in place and the comparison between the *credible option* and the *base case states of the world* must be undertaken across all *reasonable scenarios*.

For example, assuming the same two *credible options* (a network option and a demand-side option) and three *reasonable scenarios* (high, medium and low demand), it is necessary to:

- **derive** a network option, a demand-side option and *base case states of the world* under conditions of high, medium and low demand, and
- **compare** the *credible option* and *base case states of the world* under conditions of high, medium and low demand.

This will require nine market development modelling paths to establish nine *states of the world*:

(1) network option with high demand

(2) demand-side option with high demand

(3) *base case* with high demand

(4) network option with medium demand

(5) demand-side option with medium demand

(6) *base case* with medium demand

(7) network option with low demand

(8) demand-side option with low demand, and

(9) *base case* with low demand.

It will then be necessary to compare (1) and (2) against (3), (4) and (5) against (6) and (7) and (8) against (9). This should yield the market benefits of the network option and the demand-side option in each of the three *reasonable scenarios*.

For this example, assume that the network option has a market benefit of:

- $30 million in a high demand scenario
- $20 million in a medium demand scenario and

- $10 million in a low demand scenario.

Further assume that the demand-side option has a market benefit of:

- $40 million in a high demand scenario
- $10 million in a medium demand scenario and
- $5 million in a low demand scenario.

Weighting the market benefits arising in each reasonable scenario

The final step is to weight the market benefits of each *credible option* arising in each *reasonable scenario* to derive the *market benefit* of that *credible option*.

Drawing from the above example, assume that the probability of a:

- high demand scenario is 50 per cent
- medium demand scenario is 40 per cent, and
- low demand scenario is 10 per cent.

Under these assumptions, the market benefit of the:

- network option is $24 million (being 0.5*$30m + 0.4*$20m + 0.1*$10m)
- demand-side option is $24.5 million (being 0.5*$40m + 0.4*$10m + 0.1*$5m).

More detailed examples are provided below in section 3.6.

Categories of market benefit

Broadly speaking, the *market benefit* of a *credible option* can be obtained from savings in **capital costs** (including the costs of generation and network assets) and savings in **operating costs** (including fuel costs, network losses, ancillary services and load reduction (both voluntary and involuntary)). In addition, the cost savings in meeting **environmental targets** (such as the proposed Carbon Pollution Reduction Scheme (CPRS) and expanded Renewable Energy Target (expanded RET)) can also be included.

Capital cost savings

Savings in capital costs can be obtained primarily by comparing the patterns of plant development in different *states of the world* under a given *reasonable scenario*. Specifically, capital cost savings can be computed by comparing the pattern of development of *committed, anticipated* and *modelled projects* under each *credible option* to that under the *base case*.

Example 7 Capital costs under different states of the world

The *identified need* is to meet a mandatory service standard. Two *credible options* exist: a network option and a demand-side response option.

In the *base case state of the world*, in which neither *credible option* is developed, a *modelled project* is developed in year 5 at a capital cost of $150m.

In the demand-side option *state of the world*, in which only the demand-side option is developed, the same *modelled project* is developed in year 7 at a capital cost of $150m.

In the network option *state of the world*, in which only the network option is developed, no *modelled projects* are developed over the duration of the analysis.

The discount rate is 7 per cent.

Under these assumptions the contribution of capital cost savings to the market benefit of each *credible option* can be calculated as follows:

- Network option: the capital cost saving is the benefit of avoiding the $150m *modelled project* required in year 5 in the *base case state of the world*. The present value of this avoided cost is $107m.

- Demand-side participation option: the capital cost saving is the benefit of deferring the $150m *modelled project* required under both the *base case* and demand-side states of the world from year 5 to year 7:

  - present value of *modelled project* in year 5 = $107m

  - present value of *modelled project* in year 7 = $93m

  - present value of deferring *modelled project* = $107m - $93m = $14m.

In this example, taking into account only the capital cost effects, the network option results in the greatest market benefit.

Note that despite these positive contributions to *market benefit*, neither *credible option* may produce positive *net economic benefits* if the expected costs exceed the expected *market benefits*.

Operating cost savings

Savings in operating (e.g. fuel, carbon), maintenance and load reduction costs can be obtained by comparing the market dispatch outcomes in different *states of the world*.

Example 8 Operating costs under different states of the world

The following example builds on Example 7:

- Assume that in the *base case state of the world* the present value of:
  - fuel resource costs is $80m
  - unserved energy costs is $40m.
- Assume that in the network *state of the world* the present value of:
  - fuel resource costs is $100m
  - unserved energy costs is $2m.
- Assume that in the demand-side *state of the world* the present value of:
  - fuel resource costs is $80m
  - unserved energy costs is $26m.
- Under these assumptions the contribution of operating cost savings to the market benefits of each *credible option* can be calculated as follows:
  - Network option: ($80m + $40m) – ($100m + $2m) = $18m
  - Demand-side response option: ($80m + $40m) – ($80m + $26m) = $14m.

Market dispatch outcomes can be modelled using market or pool dispatch models that simulate or project wholesale spot market outcomes in the presence of each *credible option* as well as in the *base case*. Such models should operate using bid-based merit order dispatch so as to produce similar results to the dispatch algorithm used by AEMO to dispatch and settle the NEM. Any model used for the purpose of market dispatch modelling must incorporate realistic treatments of plant and network characteristics and forecast load.

In cases where the *market benefit* of none of the *credible options* under consideration is materially affected by changes in outcomes in the wholesale spot market, it may be appropriate to limit the modelling of *market benefits* to load-flow modelling. Such modelling must incorporate realistic treatments of relevant plant and network characteristics and forecast load.

Cost savings in meeting environmental targets

Savings in both capital and operating costs incurred in meeting environmental targets such as the expanded RET or proposed CPRS can be calculated by comparing plant development and market dispatch outcomes for a *credible option* to the *base case*.

In the absence of any price caps or penalties, it is reasonable to assume that both the CPRS target and expanded RET will be met: the price of an Australian Emissions

Unit (AEU) under the CPRS or the price of a Renewable Energy Certificate (REC) under the expanded RET would simply rise to the level necessary to induce compliance with the target. It follows that under any *state of the world*, the benefits from meeting that target will be identical and can hence be ignored for the purposes of the RIT-T. Differences in the resource costs of meeting these targets under different *states of the world* are reflected in the differences in other costs (i.e. capital and operating) ordinarily taken into account in the RIT-T.

If there is a cap on AEU or REC prices, or a penalty for not meeting the relevant target, the level of that price or penalty can be interpreted as the maximum per unit benefit (to the market) of providing the relevant service (i.e. carbon abatement or renewable energy). In such a case, it is possible that it will not be net beneficial (from the market's perspective) to meet the target as the cost of meeting it could exceed the benefits, as indicated by the level of the cap/penalty.

In such cases, it is conceptually appropriate to consider that the environmental benefits in each *state of the world* are equivalent, even in *states of the world* where the target is not met due to it being lower-cost to pay the cap/penalty price of RECs or AEUs in lieu of meeting the target. In a *state of the world* where the expanded RET or CPRS target is not met, the number of units of emissions or renewable energy by which the target is not met are valued at the relevant cap/penalty price and contribute to the resource costs incurred in that *state of the world*. Comparing the resource costs in different *states of the world* may then make a positive or negative contribution to the market benefits of a *credible option*.

Under the expanded RET and proposed CPRS, permit or certificate purchases represent tax deductable business expenses. However, penalties such as those to be imposed on parties who fail to surrender sufficient AEUs or RECs are generally not tax deductible expenses. Due to the asymmetric tax treatment of permit compared to penalty expenditures, the CPRS or expanded RET penalty price for the purposes of applying the RIT-T should be 'grossed up' by the applicable company tax rate to ensure that the penalty price is consistent with the post-tax AEU or REC price faced by market participants.

For example assuming a company tax rate of 30 per cent and an unadjusted penalty price of $50, the 'grossed up' penalty price for the purpose of applying the RIT-T analysis is:

$$Penalty_{GU} = \frac{Penalty}{1-t} = \frac{\$50}{1-0.3} = \$71.42$$

The AER considers this will ensure that the calculation of *market benefits* in the RIT-T reflects direct impacts on stakeholders within the NEM. This means that rational risk-neutral participants will choose to expend up to $71.42/MWh to avoid breaching the target. The value to society of meeting the target in this example is also $71.42/MWh.

Example 9 Cost savings in meeting a carbon target

A legislatively-imposed carbon trading scheme exists whereby a certain quantity of carbon dioxide-equivalent emissions must be abated over a period of time.

The scheme uses AEUs as an instrument to achieve the carbon abatement target. One AEU represents 1 tonne of carbon dioxide-equivalent emissions.

The *credible option* is the augmentation of a transmission link between two *regions*: a *region* with abundant coal-fired generation and 600 MW of load (Region A) and a *region* with abundant gas-fired generation and no load (Region B).

The capacity of:

- coal-fired generation in Region A is 750 MW
- gas-fired generation in Region B is 500 MW
- the proposed transmission augmentation is 250 MW – an increase in capacity from 250 MW to 500 MW.

The fuel and variable operating/maintenance costs of:

- coal-fired generation in Region A are $15/MWh
- gas-fired generation in Region B are $40/MWh.

The emissions intensity of:

- coal-fired generation in Region A is 1.2 tCO2-e/MWh
- gas-fired generation in Region B is 0.6 tCO2-e/MWh.

The price of AEUs (i.e. the carbon price) is $50/tCO2-e.

As a result, the carbon cost-inclusive SRMC of:

- coal-fired generation in Region A is $15+1.2*$50 = $75/MWh
- gas-fired generation in Region B is $40+0.6*$50 = $70/MWh.

In the ***base case***:

- Price is $75/MWh set by coal-fired generation in Region A
- Total dispatch costs are 250*$70 + 350*$75 = $43,750 per hour.

With the *credible option*:

- Price remains unchanged at $75/MWh.

- Total dispatch costs are 500*$70 + 100*$75 = $42,500 per hour.

Assume that the CPRS target is met with or without the *credible option*.

Assuming the same conditions over 8,760 hours in a year, the contribution of decreased fuel, variable operating/maintenance and AEU costs to the market benefit of the *credible option* is ($43,750 - $42,500)*8,760 = $10,950,000 per year.

Example 10 Cost savings in meeting a renewable energy target

A legislatively-imposed renewable energy scheme exists whereby a certain proportion of electricity generated must come from certified renewable sources.

The scheme uses RECs as an instrument to achieve the renewable energy target. One REC represents 1 MWh of renewable generation. A penalty price of $35/MWh is imposed—this means that for each MWh of energy by which the target is not met, a penalty of $35/MWh is incurred (this equates to a grossed-up penalty price of $50/MWh).

The *credible option* in question is the construction of a transmission link between two *regions*: a *region* with abundant, relatively cheap renewable generation and low load (Region A) and a *region* with limited, relatively expensive renewable generation and high load (Region B).

In the ***base case***:

- The price of RECs is $50/MWh—i.e. the price of RECs is set at the grossed-up penalty price. The market ‘chooses’ to pay the penalty price of $35/MWh and not meet the renewable target.
- The renewable target is not met by 50,000 MWh per year over the period of the analysis.
- The present value of operating and capital costs over the period of the analysis is $500m.
- The annual cost of not meeting the renewable target is 50,000*$50 = $2,500,000. The present value of these costs over the period of the analysis is $17.5m.
- The present value of operating, capital and RET penalty costs is thus $500m + 17.5m = $517.5m.

With the *credible option*:

- The price of RECs is $40/MWh and the annual renewable target is met over the period of the analysis.
- The present value of operating and capital costs over the period of the analysis is $510m. This is slightly higher than in the *base case* (where capital and operating costs sum to $500m) due to:
  - capital costs being higher (greater investment in renewable generation occurs)

- operating costs being lower (additional renewable generation displaces thermal plant)

- However, the present value of operating, capital and RET penalty costs over the period of the analysis is slightly lower than in the *base case* (where these costs sum to $517.5m) due to RET penalty costs being avoided if the *credible option* is developed.

The market benefit of the *credible option* based on these operating, capital and RET penalty costs is thus $517.5m - $510m = $7.5m.

Benefits accruing across regions

The Electricity Rules require that the RIT-T specify the method or methods permitted for estimating *market benefits* which may occur outside the *region* in which the TNSP's network is located. Similarly the application guidelines must include guidance and worked examples on the acceptable methodologies for valuing *market benefits* that accrue across *regions*.

The method outlined above for calculating *market benefits* implicitly includes *market benefits* arising across all *regions* in the NEM. For the avoidance of doubt, the RIT-T provides that the methodology for calculating *market benefits* must include *market benefits* arising in the TNSP's *region* as well as all other NEM *regions*. Given this, the AER considers that the guidance on quantifying benefits that accrue in more than one *region* is already provided as part of the more general guidance on estimating benefits. The RIT-T does not require TNSPs to **separately** quantify benefits that arise in each *region* of the NEM.

Sensitivity analysis and reasonable scenarios

As noted above, the calculation of the market benefits of a given *credible option* needs to occur across a range of *reasonable scenarios*. The number and choice of *reasonable scenarios* should reflect sensitivities in respect of the key variables and parameters that constitute a *reasonable scenario*.

For example, where there is material uncertainty over the future level of demand, the price of carbon emissions permits or the capital costs of power stations, this should be modelled through the choice of a range of *reasonable scenarios* that reflects the scope of uncertainty, each with an associated probability.

Example 11 Demand sensitivity

The *credible option* in question is the augmentation of a transmission line between two regions: Region A and Region B. The augmentation has a cost of $60m.

Region A has more plentiful generation capacity and lower generation costs than Region B. Energy and peak demand in Region A is assumed to grow by 2 per cent over the period of the analysis. Energy and peak demand in Region B is assumed to grow by 6 per cent over the period of the analysis.

The assumed discount rate is 7.5 per cent.

The major *modelled projects* in the *state of the world* **with** the *credible option* are the development of:

- a 200 MW plant in Region A in year 5 of the analysis
- a 600 MW plant in Region B in year 8 of the analysis.

In the ***base case*** the major *modelled projects* are:

- a 200 MW plant is developed in Region A in year 10 of the analysis
- a 600 MW plant is developed in Region B in year 2 of the analysis.

The market benefits of the *credible option* includes the following:

- decreased dispatch costs – cheaper generation in Region A displaces more expensive generation in Region B
- increased capital costs – the 200 MW plant in Region A is brought forward by 5 years (from year 10 to year 5)
- decreased capital costs – the required plant in Region B is delayed by 6 years (from year 2 to year 8).

The market benefits of the *credible option* is calculated to be $75m. The *net economic benefit* under these assumptions is $15m.

Assume now that a *reasonable scenario* is run on the assumption regarding growth in energy and peak demand in Region B.

The new scenario assumes growth in energy and peak demand in Region B will be 10 per cent over the period of the analysis.

Under these demand growth assumptions, the major modelled projects in the *state of the world* **with** the *credible option* are the development of:

- a 300 MW plant in Region A in year 4 of the analysis
- a 900 MW plant in Region B in year 9 of the analysis.

In the ***base case***:

- a 200 MW plant is developed in Region A in year 10 of the analysis
- a 900 MW plant is developed in Region B in year 1 of the analysis.

The present value of the market benefit of the *credible option* under these assumptions includes:

- decreased dispatch costs – cheaper generation in Region A displaces more expensive generation in Region B

- increased capital costs – the plant in Region A is larger (300 MW instead of 200 MW) and is brought forward by 6 years (from year 10 to year 4)
- decreased capital costs – the 900 MW in Region B is delayed by 8 years (from year 1 to year 9).

Due to the change in the type and timing of the *modelled projects* under the revised demand growth assumption the present value of the market benefits of the *credible option* is calculated to be $85m. The *net economic benefit* under these assumptions is $25m. The analysis shows that, in the event that growth in energy and peak demand in Region B is higher than forecast, the *credible option* will have higher market benefit than forecast.

Example 12 Lower generation capital cost sensitivity

The following example builds on Example 11.

The *credible option* is the same *credible option* from Example 11.

Growth in energy and peak demand is the same as initially assumed in Example 11—2 per cent in Region A and 6 per cent in Region B.

Generation capital costs are assumed to be 'medium'.

As in Example 11, these assumptions result in:

- a 200 MW plant being developed in Region A in year 5 of the analysis in the *state of the world* with the *credible option*, and in year 10 of the analysis in the *base case*
- a 600 MW plant being developed in Region B in year 8 of the analysis in the *state of the world* with the *credible option*, and in year 2 of the analysis in the base case.

The net economic benefit of the *credible option* is $75m - $60m = $15m.

Assume now that a sensitivity analysis is run on the assumption regarding the generation capital costs.

The new scenario assumes generation capital costs are 'low'.

Under this assumption the major *modelled projects* in the *state of the world* **with** the *credible option* are the development of:

- a 300 MW plant in Region A in year 3 of the analysis
- a 700 MW plant in Region B in year 7 of the analysis.

In the ***base case***:

- the same 300 MW plant is developed in Region A in year 8 of the analysis

- the same 700 MW plant is developed in Region B in year 1 of the analysis.

Due to the change in the type and timing of the *modelled projects*, market benefit of the *credible option* under these assumptions is calculated to be $90m. The net economic benefit under these assumptions is $30m. The sensitivity analysis shows that where generation capital costs are lower than forecast, the *credible option* will have higher market benefit than forecast.

Appropriate number of sensitivities and reasonable scenarios

Clause 5.6.5B (c)(5) and (6) of the Electricity Rules places some limitations on the depth of analysis required for calculating various classes of *market benefits* under the RIT-T. It is difficult to provide definitive guidance on the appropriate number of sensitivities – and hence, *reasonable scenarios* and *states of the world* – that may reasonably need to be derived in any given case. However, some indicative examples, which may or may not be applicable to a given *credible option* and set of circumstances, are set out below.

A $50 million investment in a network asset to increase network transfer capability in the face of load growth could be assessed:

- against one alternative *credible option* (which may be a different network option, a local generation option or a demand-side option)
- using a single discount rate
- based on a single set of capital, operating and ancillary services costs for existing, *committed*, *anticipated* and *modelled projects*
- with two alternative demand forecasts
- using competitive bidding and possibly a 'realistic' bidding approach if the merits of the investment are likely to vary significantly depending on the pattern of power flows.

While this is a relatively streamlined assessment, it nevertheless necessitates the development of:

- four *reasonable scenarios* – encompassing two different demand levels (high and low) and two different bidding approaches (competitive and realistic), and
- 12 *states of the world* – encompassing one set of *reasonable scenarios* for each of the two *credible options* and the *base case*.

Ideally, a separate market development path should be modelled for each *state of the world*. One exception to this could be bidding assumptions, as it may be infeasible or impracticable to determine how bidding behaviour could affect the pattern of plant development. Therefore, only six market development modelling paths may be required in this case:

- one for each of the two *credible options* plus the *base case*

- in both the high and low demand *reasonable scenarios*.

This is illustrated in Table 1.

Table 1 Appropriate number of sensitivities and reasonable scenarios

Reasonable scenario	**Credible option**	**Market development path**	**State of the world**
1: High demand, competitive bidding	Base case	1	1
1: High demand, competitive bidding	Option 1	2	2
1: High demand, competitive bidding	Option 2	3	3
2: High demand, strategic bidding	Base case	1	4
2: High demand, strategic bidding	Option 1	2	5
2: High demand, strategic bidding	Option 2	3	6
3: Low demand, competitive bidding	Base case	4	7
3: Low demand, competitive bidding	Option 1	5	8
3: Low demand, competitive bidding	Option 2	6	9
4: Low demand, strategic bidding	Base case	4	10
4: Low demand, strategic bidding	Option 1	5	11
4: Low demand, strategic bidding	Option 2	6	12

A $400 million new interconnector to increase the sum of consumer and producer surplus in the NEM could reasonably be assessed:

- against at least two alternative *credible options*
- using two alternative discount rates
- based on two sets of capital, operating and ancillary services costs for existing, *committed*, *anticipated* and *modelled projects*
- with three alternative demand forecasts
- using both competitive and realistic bidding approaches.

This necessitates the development of:

- 24 *reasonable scenarios* – encompassing three different demand levels (high, medium and low), two discount rates (high and low), two sets of plant costs (high and low) and two different bidding approaches (competitive and realistic), and

- 96 *states of the world* – encompassing one set of *reasonable scenarios* for each of the three *credible options* and the *base case*.

The number of *reasonable scenarios* and required *states of the world* in applying the RIT-T analysis would again multiply if further variation in some of the input assumptions were permitted, such as the use of alternative values of unserved energy or the use of a market-driven market development modelling approach, or if more alternative *credible options* needed to be compared.

3.6 Uncertainty and risk

The AER recognises that at the time of applying the RIT-T the future will be uncertain. Given this, the expected *costs* and *market benefits* of a *credible option* (and therefore the *net economic benefit*) may be uncertain. This uncertainty may have a material impact on the selection of the *preferred option*. The following provides information and guidance on how a TNSP can respond to uncertainty when applying the RIT-T.

Uncertainty regarding market benefits and costs

Where there is material uncertainty over the future market supply and demand conditions and characteristics which affect the calculation of the *market benefits* or *costs* of a *credible option*, this is to be primarily be reflected in the choice of the **range of *reasonable scenarios***. Those *reasonable scenarios* should reflect the range of potential future outcomes. Associated with each *reasonable scenario* is a probability corresponding to the likelihood of that scenario occurring. The *market benefit* of a *credible option* is the probability-weighted sum of the market benefits of that option arising across all *reasonable scenarios*.

The requirement for *market benefits* and *costs* to be probability-weighted represents a minor additional step compared to the process of ranking *credible options* based on market benefits across a range of *reasonable scenarios* as was required under the previous regulatory test.

The methodology for assigning probabilities to each *reasonable scenario* will depend on the methodology for defining the *reasonable scenario*. For example, where there is uncertainty about future demand, two different methodologies are possible:

- In the first approach, a range of equally-spaced values for future demand is chosen, and probability weightings for each of these values chosen. Under this approach, the possible values of demand are equally spaced across the range of possible outcomes, but extreme values of future demand will receive a lower probability than values closer to the mean.

- Under the second approach, different possible values for future demand are ranked, and then divided up into groups – quartiles, or deciles, etc. A representative value for demand from each group is then selected. Under this approach the probability assigned to each representative value is the same – 25 per cent in the case of quartiles, 10 per cent in the case of deciles, etc. Under this approach, the probability of each demand value arising is constant, but the chosen representative demand values are grouped closer together for values of demand closer to the mean.

Either approach is acceptable. However the methodology for assigning probabilities to each *reasonable scenario* must be consistent with the methodology for choosing the *reasonable scenarios* themselves.

Where a TNSP has no material evidence for assigning a higher probability for one *reasonable scenario* over another, a TNSP may weight all *reasonable scenarios* equally.

Market benefits

The method for calculating *market benefits* across a probability weighted range of *reasonable scenarios* is demonstrated in Example 13 below.

Example 13 Calculating expected market benefit

A TNSP is considering three *credible options* across four *reasonable scenarios*.

The three *credible options* are:

- a network option (Credible option 1)
- a generation option (Credible option 2)
- a demand-side option (Credible option 3).

The four *reasonable scenarios* are:

- High capital costs; High demand (Scenario 1)
- High capital costs; Low demand (Scenario 2)
- Low capital costs; High demand (Scenario 3)
- Low capital costs; Low demand (Scenario 4).

The following probabilities of occurrence are assigned to each of the above *reasonable scenarios*:

- High capital costs; High demand (Scenario 1) = 10 per cent
- High capital costs; Low demand (Scenario 2) = 25 per cent
- Low capital costs; High demand (Scenario 3) = 45 per cent
- Low capital costs; Low demand (Scenario 4) = 20 per cent.

A ranking of these three *credible option*s across each of the four *reasonable scenarios* according to market benefit relative to a *base case* is presented in Table 2 below.

Table 2 Ranking credible options across reasonable scenarios ($m)

Credible option	**Market benefit**			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Network option	$7m	-$10m	$30m	-$2m
Generation option	$10m	$1	$25m	$5m
Demand-side option	$2m	$10m	-$5m	$2m

Calculating the (probability-weighted) *market benefit* across the range of *reasonable scenarios* requires one step in addition to the analysis required to generate the results in Table 2. For each *credible option*, the market benefit under each *reasonable scenario* must be weighted by that *reasonable scenario's* probability of occurrence. This generates one *market benefit* estimate for each *credible option*, as outlined in Table 3 below.

Table 3 Calculating expected market benefit ($m)

Credible option	**Market benefit**				**Probability weighted market benefit**
	Scenario 1	Scenario 2	Scenario 3	Scenario 4	
Network option	$7m	-$10m	$30m	-$2m	$11.3m
Generation option	$10m	$1	$25m	$5m	$13.5m
Demand-side option	$2m	$10m	-$5m	$2m	$0.9m

Costs

Where there is a material degree of uncertainty in the *costs* of a *credible option*, paragraph 2 of the RIT-T requires a TNSP to calculate the expected cost of the option under a range of different reasonable cost assumptions. In these circumstances, the *cost* of the *credible option* is the probability weighted present value of the direct costs of the *credible option* under the different cost assumptions.

For the avoidance of doubt, the term 'cost assumptions' is distinct from the term *reasonable scenarios* used elsewhere in the RIT-T and these application guidelines.

The direct costs of a *credible option* may vary for reasons other than the nature of the relevant *reasonable scenario*. For example, the direct costs of a *credible option* may be uncertain because they depend on variables such as exchange rates, the price of copper or the price of thermal coal. Similarly, whether a *reasonable scenario* reflects high or low demand growth is unlikely to affect the *costs* of a *credible option*. This is why the RIT-T requires the TNSP to separately undertake a weighted averaging of the direct costs of a *credible option* as well as the *market benefits* of a *credible option*.

Example 14 Calculating expected cost

The following example continues on from Example 13. For each of the three *credible options* the TNSP also considered three cost assumptions ('Low', 'Medium' and 'High').

The three cost assumptions and associated probabilities of occurrence for each *credible option* were:

- Network option:
  - Low (low steel prices; favourable exchange rate) = 15 per cent
  - Medium (medium steel prices; average exchange rate) = 55 per cent
  - High (high steel prices; unfavourable exchange rate) = 30 per cent.
- Generation option:
  - Low (low steel prices, low labour costs) = 10 per cent
  - Medium (medium steel prices; medium labour costs) = 50 per cent
  - High (high steel prices; high labour costs) = 40 per cent.
- Demand-side option:
  - Low (low implementation and maintenance costs) = 30 per cent
  - Medium (medium implementation and maintenance costs) = 50 per cent
  - High (high implementation and maintenance costs) = 20 per cent.

As was calculated for the *market benefits* of each *credible option*, an expected *cost* can be calculated for each *credible option* by taking a weighted-average across cost assumptions. This is outlined in Table 4 below.

Table 4 Calculating expected cost ($m)

Credible option	**Cost scenario**			**Expected cost**
	Low	Medium	High	
Network option	$7.5m	$10m	$17.5m	$11.9m
Generation option	$8m	$12m	$14m	$12.4m
Demand-side option	$0.4m	$0.5m	$0.75m	$0.5m

Developing credible options

Where the future is uncertain, the TNSP may consider investment options which retain some flexibility and allow it to respond to new information that arises in the future. For example where there is material uncertainty about future demand growth, the set of *credible options* considered by the TNSP could include an option which allows the TNSP to make a smaller network investment now, but retain flexibility to upgrade the line at reduced cost later.

Clause 5.6.5B(c)(4)(ix) of the Electricity Rules requires a TNSP applying the RIT-T to consider option value as a class of potential *market benefit* that could be provided by a *credible option*.

Option value refers to a benefit that results from retaining flexibility in a context in which certain actions are irreversible (sunk), and new information may arise in the future as to the payoff from taking a certain action.

Many TNSP decisions are partially or fully irreversible, such as the decision to undertake a major augmentation of the transmission network. In some cases past decisions are reversible, but only at an increased cost. For example, a TNSP might decide to purchase land for a substation in an area where land remains inexpensive. If later, twice as much land is required, and the surrounding areas are fully built up, expanding the substation, while potentially still feasible, is significantly more costly.

If, when a decision is being taken to carry out a partially or fully irreversible action, it is known that new information will arrive in the future which may affect the *market benefit* of that action, there may also be a value in retaining some flexibility to respond to that new information as or when it emerges. For example, if demand for a transmission line is uncertain but might increase, a TNSP might wish to retain the flexibility to expand the capacity of the transmission line at a relatively low cost in the future. If demand for a transmission line is uncertain but might decrease, a TNSP may prefer to implement a temporary (perhaps a non-network) solution to congestion problems, and defer a major sunk investment until such time as the demand for the transmission line is clear.

These benefits of retaining flexibility can be captured when applying the RIT-T. The RIT-T allows for the identification of options where the decision-maker is able to change its action in response to new information that arrives in the future. In other words, the RIT-T effectively allow for two-stages of decisions—in the first stage, whether to build in flexibility (that is, whether to commit to a particular approach); in the second stage (if flexibility is allowed at the first stage), whether to partially or completely reverse the earlier decision.

The example below demonstrates how this option value can be captured when applying the RIT-T.

Example 15 Taking into account the value of flexibility

This example is based on Example 13 and Example 14. To simplify this example, assume that future capital costs are known with certainty and the only uncertainty is the rate of demand growth, which may be high or low.

In Example 13 there were three *credible options* (a network option, a generation option and a demand-side option). In this example assume that the TNSP can put in place an option which is sufficient to cater for all future demand scenarios—in particular, high demand growth. Alternatively the TNSP can also choose to put in place a smaller, cheaper option. This would be sufficient in the longer-term if demand growth turns out to be low. However, it would prove to be insufficient, requiring a subsequent upgrade, if demand growth turns out to be high.

To specify each *credible option*, the TNSP must specify (a) what action it will take in the short-term; and (b) in the event that demand turns out to be high, what further action it will take in the longer term. Assume that the subsequent upgrade would be a network option.

Under these assumptions, there are six *credible options*:

(1) a full-scale network upgrade (sufficient to handle the high-growth scenario)

(2) a full-scale generation option (again, sufficient for the high-growth scenario)

(3) a full-scale demand-side option (again, sufficient for the high-growth scenario)

(4) a small-scale network upgrade (sufficient to handle the low-growth scenario) coupled with the ability to carry out a further network upgrade in the future should demand turn out to be high

(5) a small-scale generation option coupled with the ability to carry out a further network upgrade in the future should demand turn out to be high

(6) a small-scale demand-side option coupled with the ability to carry out a further network upgrade in the future should demand turn out to be high.

For each of these six *credible options,* there are two *reasonable scenarios* to consider—a low demand growth scenario and a high demand growth scenario (each with potentially its own market development path). Assume a probability of 50 per cent to each of the high and low demand growth scenarios.

The (unweighted) market benefits and costs of each of these *credible options* in each *reasonable scenario* are set out in Table 5 below. Note that in the case of the “small-scale” options, the cost incurred is larger in the event of the high demand growth scenario, as this cost takes into account the cost of the further network upgrade required.

Table 5 Calculating expected net market benefit ($m)

Credible option	Demand scenario	Market benefits	Costs	Net economic benefit
1. Full-scale network option	High	$30m	$11.9m	$18.1m
1. Full-scale network option	Low	$-2m	$11.9m	$-13.9m
2. Full-scale generation option	High	$25m	$12.4m	$12.6m
2. Full-scale generation option	Low	$5m	$12.4m	$-7.4m
3. Full-scale demand-side option	High	$-5m	$0.5m	$-5.5m
3. Full-scale demand-side option	Low	$2m	$0.5m	$1.5m
4. Small-scale network option	High	$30m	$13.6m	$16.4m
4. Small-scale network option	Low	$-2m	$5.3m	$-7.3m
5. Small-scale generation option	High	$25m	$14.4m	$10.6m
5. Small-scale generation option	Low	$5m	$6.4m	$-1.4m
6. Small-scale demand-side option	High	$-5m	$5.5m	$-10.5m
6. Small-scale demand-side option	Low	$2m	$0.3m	$1.7m

Calculating the (probability-weighted) *market benefit* across the range of *reasonable scenarios* requires one step in addition to the analysis required to generate the results in Table 5. For each *credible option*, the market benefit under each *reasonable scenario* must be weighted by that *reasonable scenario's* probability of occurrence. This generates one *market benefit* estimate for each, as outlined in Table 6 below.

Table 6 Calculating expected market benefit ($m)

Credible option	Probability weighted market benefit	Probability weighted cost	Net economic benefit
1. Full-scale network option	$14m	-$11.9m	$2.1m
2. Full-scale generation option	$15m	$12.4m	$2.6m
3. Full-scale demand-side option	$-1.5m	$0.5m	$-2m
4. Small-scale network option	$14m	$9.5m	$4.5m

5. Small-scale generation option	$15m	$10.4m	$4.6m
6. Small-scale demand-side option	$-1.5m	$2.9m	$-4.4m

In this example, that the *preferred option* is the small-scale generation option. This is the *credible option* with the largest *net economic benefit*, taking into account a probability-weighting over the applicable market benefits and *costs*.

In applying the RIT-T, there is no requirement to separately identify the option value, that is the value associated with retaining flexibility to respond to new information in the future. However, in this example, it is possible to give a concrete interpretation to the notion of option value. As can be seen in the table above, carrying out the small-scale generation option (which avoids the cost of a larger scale investment today, allowing such an investment to occur only if it is strictly required), yields an additional $2m in *net economic benefit* compared to the full-scale generation option. This additional $2m can be interpreted as the value of retaining flexibility to respond to new information as it arises in the future.

The AER believes that appropriate identification of *credible options* and *reasonable scenarios* captures any option value, thereby meeting the Electricity Rule requirement to consider option value as a class of *market benefit* under the RIT-T.

However, the RIT-T allows for any additional option value not captured in the existing classes of *market benefits* to be considered. Paragraph (5)(i) of the RIT-T provides that *market benefit* includes the present value of “any additional option value (meaning any option value that has not already been included in other classes of *market benefits*) gained or foregone from implementing the *credible option* with respect to the likely future investment needs of the *market*.”

Inclusion of this provision in the RIT-T ensures that if TNSPs are able to develop a notion of option value beyond that captured by probability weighting of *credible options* over a range of *reasonable scenarios*, they are not precluded from applying this approach to determining option value. Importantly this provision allows for the identification of option value only where it has not already been captured elsewhere in the cost-benefit assessment under the RIT-T.

3.7 Selecting the preferred option

Under the RIT-T, the *preferred option* is the *credible option* that maximises the *net economic benefit* compared to all other *credible options*. The *net economic benefit* of a *credible option* is simply the *market benefit* less the *costs* of the *credible option*. Where an *identified need* is for *reliability corrective action* the *preferred option* may have a net economic cost.

Example 16 Calculating expected net market benefit

This example builds on Example 13 and Example 14. Combining the information in Table 3 and Table 4 allows calculation of a single *net economic benefit* estimate for each *credible option*. The *net economic benefit* of each of the *credible option*s considered in Example 13 and Example 14 above is outlined in Table 6 below.

Table 6 Calculating expected net market benefit ($m)

Credible option	**Market benefits**	**Costs**	**Net economic benefit**
Network option	$11.3m	$11.9m	-$0.6m
Generation option	$13.5m	$12.4m	$1.1m
Demand-side option	$0.9m	$0.5m	$0.4m

The *preferred option* in this example is the generation option.

3.8 Externalities

Under the RIT-T, externalities are economic impacts that accrue to parties other than those who produce, consume and transport electricity in the market (see clause 5.6.5B(c)(9) of the Electricity Rules). As such, externalities are not included in either the *costs* or *market benefits* of a *credible option* and are therefore not included in the determination of *net economic benefit*.

It is worth clarifying the AER's interpretation of this provision. As virtually all individuals and businesses located in the geographic NEM consume electricity, the AER recognises clause 5.6.5B(c)(9) may be read as only trivially limiting the scope of costs or benefits to be considered under the RIT-T. However, the AER considers that this interpretation would conflict with the intention of clause 5.6.5B(c)(9).

Therefore, the AER interprets the qualifier 'consumers of electricity' in clause 5.6.5B(c)(9) as referring to costs or benefits incurred or obtained, respectively, by parties **in their capacity as consumers of electricity**. Thus, costs or benefits which arise but are incidental to parties' electricity consumption should be excluded from an analysis under the RIT-T.

Examples of negative and positive externalities are set out below.

Example 17 Negative externality

The *credible option* is a local gas-fired peaking generator, planned for development in close proximity to an existing hotel.

The development of the generator is expected to reduce the nearby hotel's annual earnings (due to a loss of visual amenity) – the present value of this loss is $15m.

In this example the $15m cost borne by the hotel's proprietor is a negative externality – this cost is driven by the development of the gas-fired peaking generator, but it is not borne by the generator's developer and is therefore not part of the costs of the generator.

Example 18 Positive externality

The *credible option* is the development of a large-scale wind farm located near a small town.

The development of the wind farm is expected to increase the annual earnings of the town's restaurant during the duration of the wind farm's construction, due to a large number of construction workers temporarily residing in the town – the present value of these increased earnings is $1m.

In this example the $1m benefit reaped by restaurant's proprietor is a positive externality – this benefit is driven by the development of the wind farm, but it is not realised by the wind farm's developer or any other NEM party in their capacity as consumers of electricity and is hence not part of the market benefits of the wind farm.

3.9 Suitable modelling periods

The duration of modelling periods should take into account the size, complexity and expected life of the relevant *credible option* to provide a reasonable indication of the *market benefits* and *costs* of the *credible option*. This means that by the end of the modelling period, the network is in a 'similar state' in relation to needing to meet a similar *identified need* to where it is at the time of the investment.

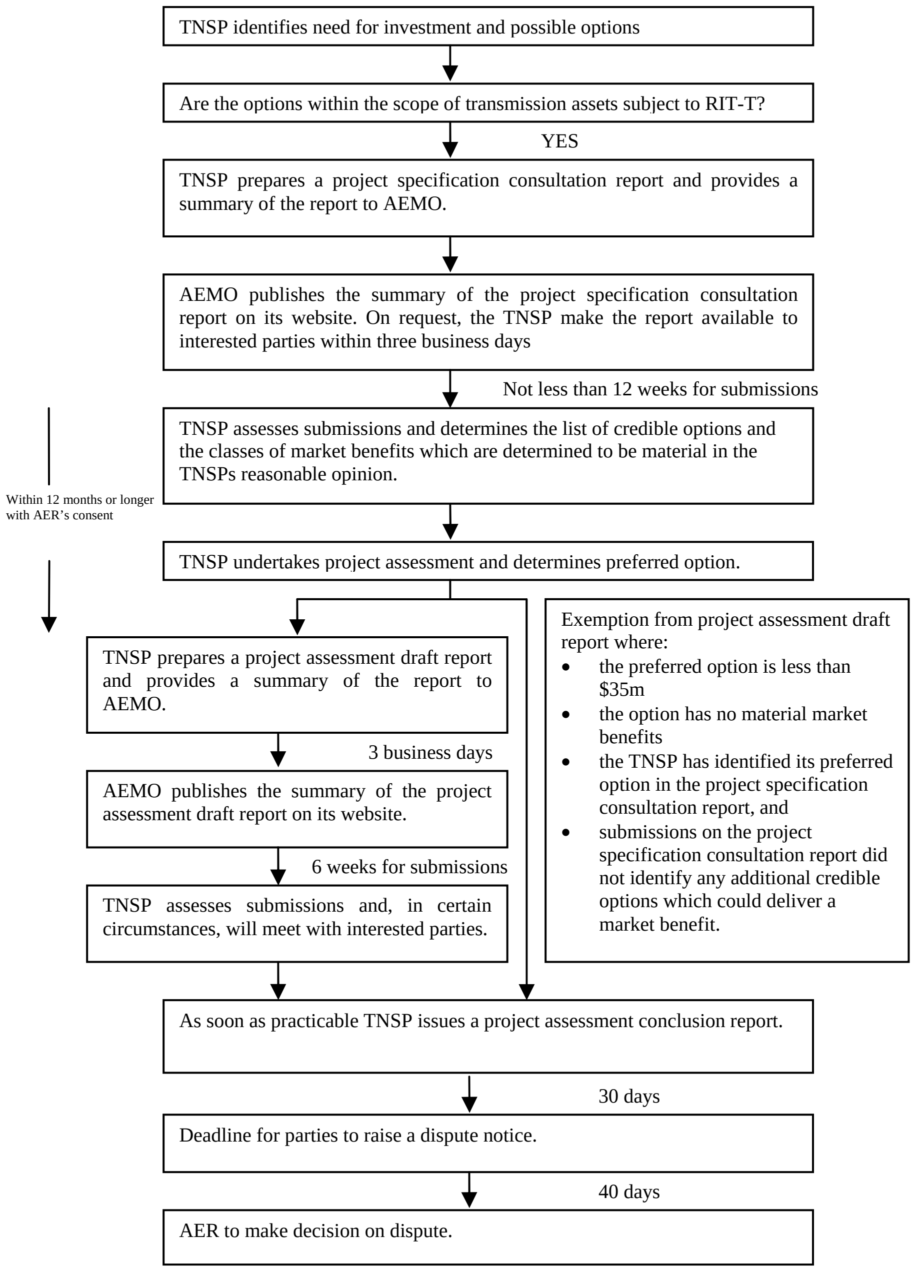
It is difficult to provide definitive guidance on how this principle should be implemented. However, it is unlikely that a period of less than 5 years would adequately reflect the *market benefits* of any *credible option*. In the case of very long-lived and high-cost investments, it may be necessary to adopt a modelling period of 20 years or more.

4 Process to be followed in applying the RIT-T

This part of the guideline summarises the process that a TNSP must follow when applying the RIT-T as set out in the Electricity Rules. It summarises each stage of the process for applying the RIT-T.

Clause 5.6.6 establishes a three stage process for applying the RIT-T: the *project specification consultation report*, project assessment draft report and project assessment conclusions report. If a proposed *transmission investment* is subject to a RIT-T assessment, a TNSP must follow the three stage process. This process is summarised below. A flow chart of the consultation and assessment process is also set out at figure 1.

Figure 1 RIT-T assessment and consultation process



4.1 Stage one: Project specification consultation report

The TNSP must prepare a *project specification consultation report* setting out certain information about the proposed *transmission investment*. A TNSP is not required to make the *project specification consultation report* separately available if it includes the report as part of its *annual planning report*.

Information required for project specification consultation report

The *project specification consultation report* must set out the following:

- the *identified need* for the investment
- assumptions used in identifying the *identified need*. Where a TNSP considers *reliability corrective action* is required, it must include reasons why this action is necessary.
- the technical characteristics of the *identified need* that a non-network option would be required to deliver, such as the size of load reduction or additional supply, location and operating profile
- a description of all *credible options* that the TNSP considers address the *identified need*
- for each *credible option* identified, information about:
  - the technical characteristics of the *credible option*
  - whether the *credible option* is likely to have a material inter-regional impact
  - the classes of *market benefits* that the TNSP considers are unlikely to be material and reasons why the TNSP considers that these classes of *market benefits* are unlikely to be material
  - the estimated construction timetable and commissioning date, and
  - to the extent practicable, the total indicative capital and maintenance costs.

Consultation process

The TNSP must make the *project specification consultation report* available to all registered participants, AEMO and interested parties.[9] Below is a summary of the important stages in the consultation process:

- Within five *business days* of making the *project specification consultation report*, the TNSP must provide a summary of the report to AEMO. AEMO will publish the summary on its website within three *business days* of receiving the summary.
- Upon request, a TNSP must make their *project specification consultation report* available to an interested party within three *business days*.

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[9] Registered participant and interested party are defined in chapter 10 of the National Electricity Rules.

- While not a requirement in the Electricity Rules, the AER considers it best practice for a TNSP to also publish its *project specification consultation report* (or the summary of the report) and the closing date and requirements for submissions on the TNSP's website.

- A TNSP must seek submissions from registered participants, AEMO and interested parties on the *credible options* presented and the issues addressed in the *project consultation specification report*.

- The period for submissions must be at least 12 weeks from the date AEMO publishes the summary on its website.

4.2 Stage two: Project assessment draft report

If a TNSP decides to proceed with the proposed *transmission investment*, it must prepare a *project assessment draft report* within:

- 12 months of the end of the consultation period under stage one, or

- a longer period agreed to by the AER in writing.

A TNSP is not required to make a separate *project assessment draft report* available if it includes the report as part of its *annual planning report* and this report is published within 12 months of the end of the consultation under stage one (or the longer period agreed to by the AER).

Information required for project assessment draft report

The *project assessment draft report* must include the following information:

- a description of each *credible option* assessed

- a summary of, and commentary on, the submissions received

- a quantification of the *costs* (including a breakdown of the operating and capital expenditure) and classes of material *market benefit* for each *credible option*

- where relevant, the reasons why the TNSP has determined that a class of *market benefit* is not material

- a detailed description of the method used to quantify each class of material *market benefit* and *cost*

- the identity of any class of *market benefit* estimated to arise outside the TNSP's *region* and a quantification of the value of such benefits (in aggregate across all *regions*), and

- the results of a net present value analysis of each *credible option* and accompanying explanatory statements regarding the results

- the proposed *preferred option* and details on its technical characteristics, estimated construction timetable and commissioning date and a statement and analysis that the *preferred option* satisfies the RIT-T.

Consultation process

The TNSP must make the *project assessment draft report* available to registered participants, AEMO and interested parties. Below is a summary of the important stages in the *project assessment draft report* process:

- Within five *business days* of making the *project assessment draft report*, TNSPs must provide a summary of the report to AEMO. AEMO will publish the summary on its website within three *business days*.

- Upon request, a TNSP must make their *project assessment draft report* available to an interested party within three *business days*.

- While not a requirement in the Electricity Rules, the AER considers it best practice for a TNSP to also publish its *project assessment draft report* (or the summary of the report) and the closing date and requirements for submissions on the TNSP's website.

- A TNSP must seek submissions from registered participants, AEMO and interested parties on the *preferred option* presented and the issues addressed in the *project assessment draft report*.

- The period for submissions must be at least 6 weeks from the date AEMO publishes the summary on its website.

- An interested party, a registered participant or AEMO (each known as a *relevant party*) may request a meeting with the TNSP within four weeks of the end of the consultation period. However a TNSP is only *required* to hold a meeting if a meeting is requested by at least two relevant parties. The TNSP *may* meet with a relevant party if after considering all submissions it considers that the meeting is necessary.

Exemption from preparing a project assessment draft report

Under certain circumstances, *transmission investment*s do not require a *project assessment draft report*. Under clause 5.6.6(y) of the Electricity Rules, TNSPs are exempt from providing a *project assessment draft report* if all of the following conditions are met:

- the estimated capital cost of the *preferred option* is less than $35 million (the AER must review this threshold every three years)[10]

- the TNSP has identified in its consultation report its *preferred option*, its reasons for that option and noted that it will be exempt from publishing the draft report for its *preferred option*

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[10] For further details see footnote 1.

- the TNSP considers that the *preferred option* and any other *credible options* do not have a material *market benefit* (other than benefits associated with changes in voluntary load curtailment and involuntary load shedding), and
- the TNSP forms the view that submissions on the *project specification consultation report* did not identify additional *credible options* that could deliver a material *market benefit*.

4.3 Stage three: Project assessment conclusions report

As soon as practicable after the consultation period for the *project assessment draft report*, the TNSP must consider all submissions received and publish and make available to all registered participants, AEMO and interested parties[11] a *project assessment conclusions report*.

Where a TNSP is exempt from preparing a *project assessment draft report*, the TNSP must make the conclusions report available within 12 months of the end of the consultation period under stage one.

A TNSP is not required to make the *project assessment conclusions report* available if it includes the report as part of its *annual planning report*.

Information required for project assessment conclusions report

The *project assessment conclusions report* must set out:

- the matters required in the *project assessment draft report* (see information required for *project assessment draft report* in stage two above), and
- a summary of, and the TNSP's response to, submissions received from interested parties regarding the *project assessment draft report*. If a TNSP is exempt from preparing a *project assessment draft report*, the *project assessment conclusions report* must address any issues raised during consultation under stage one.

Publishing final report

Below is a summary of the stages for publishing and making the *project assessment conclusions report* available to registered participants, AEMO and interested parties:

- Within five *business days* of making the *project assessment conclusions report*, the TNSP must provide a summary of the report to AEMO. AEMO will publish the summary on its website within three *business days*.
- Upon request, a TNSP must make their *project assessment conclusions report* available to an interested party within three *business days*.
- The TNSP must also publish the *project assessment conclusions report* by making it available to registered participants electronically.

[11] Registered participant, interested party and AEMO are defined in chapter 10 of the National Electricity Rules.

- While not a requirement of the Electricity Rules, the AER considers it best practice for a TNSP to also publish the *project assessment conclusions report* on its website as well as the date that this report was published. The TNSP may also note on its website that a process exists for resolving RIT-T disputes and the timeframes for lodging a dispute notice with the AER.

5 RIT-T dispute resolution

5.1 Introduction

Clause 5.6.6A of the Electricity Rules sets out a dispute resolution process for disputing the conclusions made by a TNSP in the *project assessment conclusions report*. This part of the application guidelines summarises the process that a disputing party, a TNSP and the AER must follow when involved in dispute resolution as set out in the Electricity Rules. It provides information on who may dispute a RIT-T assessment; what matters can be disputed; how to lodge a dispute; and the process the AER, a TNSP and disputing parties must follow in resolving a dispute.

AER’s role in RIT-T disputes

The AER is responsible for resolving all disputes relating to certain conclusions in the *project assessment conclusions report*. Eligible parties may apply to the AER for a finding on the disputed conclusion.

Clause 5.6.6AA of the Electricity Rules also allows a TNSP to apply to the AER to determine whether a preferred project satisfies the RIT-T even if a dispute has not been raised.

5.2 Requirements for making a RIT-T dispute

Who can dispute a RIT-T assessment?

A dispute can *only* be lodged by the following parties:

- registered participants
- the Australian Energy Market Commission (AEMC)
- connection applicants
- intending participants
- AEMO, and
- interested parties

In addition to the AEMC and AEMO, the Electricity Rules define these eligible dispute parties as:

> **Registered participant**
>
> A person who is registered by *AEMO* in any one or more of the categories listed in clauses 2.2 to 2.7 (in the case of a person who is registered by *AEMO* as a *Trader*, such a person is only a *Registered Participant* for the purposes referred to in clause 2.5A). However, as set out in clause 8.2.1(a1), for the purposes of some provisions of clause 8.2 only, *AEMO* and *Connection Applicants* who are not otherwise *Registered Participants* are also deemed to be *Registered Participants*.

Connection applicant

A person who wants to establish or modify *connection* to a *transmission network* or *distribution network* and/or who wishes to receive *network services* and who makes a *connection enquiry* as described in clause 5.3.2

Intending participant

A person who is registered by *AEMO* as an *Intending Participant* under Chapter 2.

Interested party

(a) In Chapter 5, a person including an end user or its *representative* who, in *AEMO's* opinion, has or identifies itself to *AEMO* as having an interest in relation to the *network* planning and development activities covered under rule 5.6 or in the determination of *plant standards* covered under clause 5.3.3(b2).

(b) Despite the definition in (a) above, in clauses 5.6.6 and 5.6.6A a person including an end user or its *representative* who, in the *AER's* opinion, has or identifies itself to the *AER* as having the potential to suffer a material and adverse market impact from the proposed *transmission investment* that is the *preferred option* identified in the *project assessment conclusions report*.

(c) …

In the Electricity Rules and these application guidelines a person/party disputing a conclusion in the *project assessment conclusions report* is referred to as a disputing party.

What can be disputed?

The disputing party can only dispute conclusions made by the TNSP in the *project assessment conclusions report* regarding:

- the application of the RIT-T
- the basis on which the TNSP has classified the *preferred option* as being for *reliability corrective action*, or
- the TNSP's assessment about whether the *preferred option* will have a material inter-network impact in accordance with any criteria for a material inter-network impact that is in force at the time of preparing the *project assessment conclusions report*.

Matters that may not be disputed

A dispute may not be raised about any issues outlined in the *project assessment conclusions report* which:

- are treated as externalities by the RIT-T, or
- relate to an individual's personal detriment or property rights.

For further guidance and examples on the matters that are treated as externalities by the RIT-T see section 3.8 of this application guideline.

Lodging a dispute and information required

Within 30 days of the TNSP publishing the *project assessment conclusions report* the disputing party must:

- give notice of the dispute in writing setting out the grounds for the dispute to the AER, and
- at the same time, provide a copy of the dispute notice to the relevant TNSP.

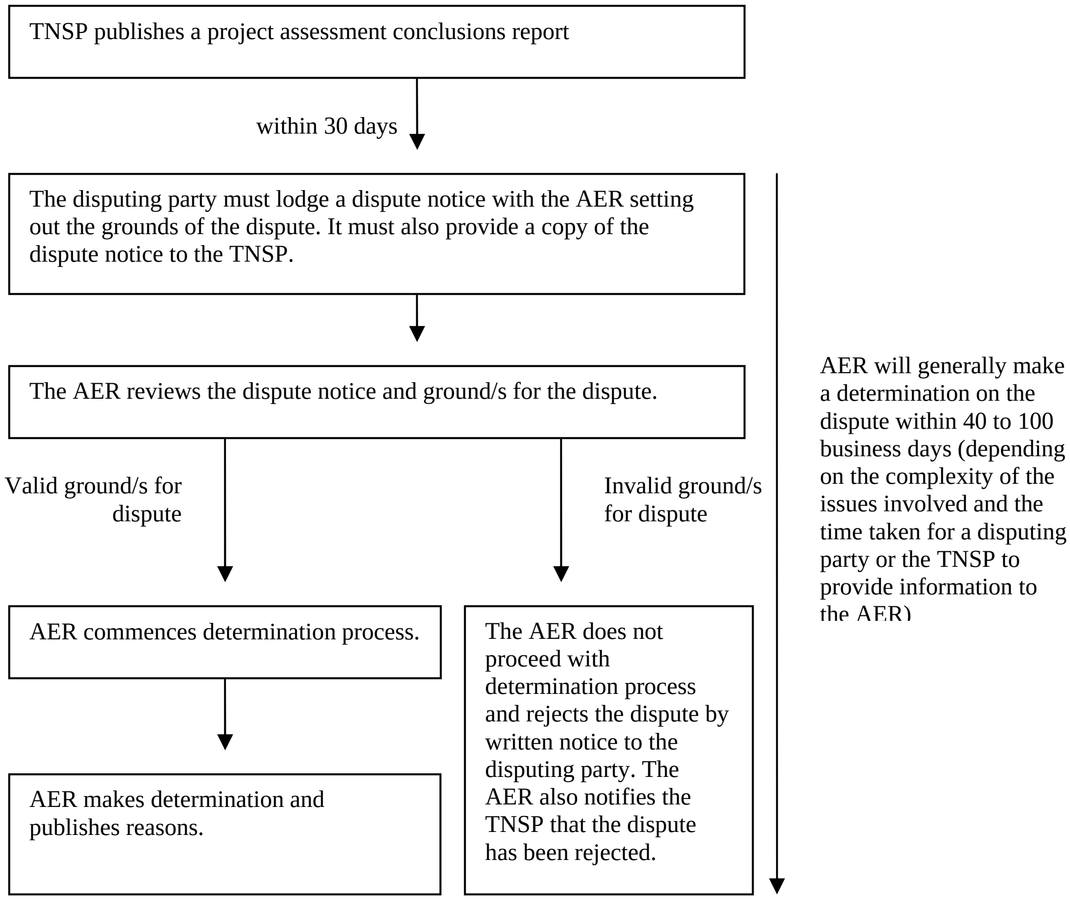
The dispute notice should include the following information:

- the disputing party's name, a contact officer, address, email and telephone number
- the ground/s for the dispute
- any submissions the disputing party made regarding the TNSP's *project specification consultation report*, the *project assessment draft report* and the *project assessment conclusions report* (if applicable)
- the TNSP's reply to any submissions made by the disputing party regarding the *project assessment conclusions report* (if applicable)
- details of any meetings held by the TNSP with the interested party (if applicable), and
- the details of any other known parties involved in the matter.

5.3 Procedure for a dispute

The AER, TNSPs and disputing parties all have different obligations under clause 5.6.6A of the Electricity Rules to ensure the timely resolution of disputes. Figure 2 summarises the process for resolving RIT-T disputes.

Figure 2 Dispute resolution process



Timeframe for resolving disputes

The AER must either reject the dispute or make and publish a determination:

- within 40 days of receiving the dispute notice, or
- within a period of up to an additional 60 days where the AER notifies interested parties that the additional time is required to make a determination because of the complexity or difficulty of the issues involved.

Extension of timeframe – request for additional information

The AER may also extend the time for making its determination if it has requested further information regarding a dispute from the disputing party or the TNSP, provided:

- the AER makes the request for the additional information at least seven *business days* prior to the expiry of the period for making its determination, and
- the TNSP or disputing party provides the additional information within 14 *business days* of receipt of the request.

Under these circumstances the AER may extend the time for making its determination by the time it takes the disputing party or TNSP to provide the requested information to the AER.

AER determination

After considering the dispute notice and any other relevant information, the AER must either reject the dispute or make and publish a determination.

If the AER rejects the dispute

The AER must:

- reject the dispute by written notice to the disputing party if the AER considers that the grounds for the dispute are misconceived or lacking in substance, and
- notify the TNSP that the dispute has been rejected.

If the AER does not reject the dispute

The AER must make and publish a determination:

- stating that, based on the grounds of the dispute, the TNSP will not need to amend the *project assessment conclusions report*, or
- directing the TNSP to amend the matters set out in the *project assessment conclusions report*.

Scope of AER determination

The AER may only determine that the TNSP amend the matters set out in the *project assessment conclusions report* if it determines that:

- the TNSP has incorrectly applied the RIT-T
- the TNSP has erroneously classified the *preferred option* as being for *reliability corrective action*
- the TNSP has incorrectly assessed whether the *preferred option* will have a material inter-network impact, or
- there was a manifest error in the calculations performed by the TNSP in applying the RIT-T.

Expert consultants

The AER may engage an expert to provide advice. Given the level of technical and engineering detail involved in RIT-T assessments, such experts may include engineers, economists or experts in the electricity industry.

It is likely that an engineering consultant would be needed to advise the AER on the engineering/planning aspects where the *identified need* is for *reliability corrective action*. Given the complex economic modelling and analysis required, the AER may also require an economic consultant to assist in resolving disputes regarding the quantification of *market benefit*s.

Material the AER may consider

In making a determination on the dispute, the AER:

- must only take into account information and analysis that the TNSP could reasonably be expected to have considered or undertaken at the time it performed the RIT-T, and
- may disregard any matter raised by the disputing party or the TNSP that is misconceived or lacking in substance.

The following material is likely to be relevant to the AER's consideration:

- the dispute notice
- the project specification report, the *project assessment draft report* and *project assessment conclusions report* (as applicable)
- any expert advice or reports on the proposed asset
- AEMO's National Transmission Network Development Plan and/or National Transmission Statement, the TNSP's *annual planning report*s and any other relevant planning publications.
- relevant planning criteria, reliability requirements or jurisdictional licensing requirements, and
- relevant regulatory decisions relating to the proposed asset.

Requests for further information

Under clause 5.6.6A(e)(3) of the Electricity Rules the AER may also request further information from the disputing party and TNSP. The disputing party or the TNSP must provide any additional information requested by the AER as soon as reasonably practicable.

A request for further information will be in writing and the notice will explain that:

- the request is being made under clause 5.6.6A(e)(3) of the Electricity Rules,
- the timeframe within which the TNSP or disputing party should provide the information (generally 14 *business days*), and
- under clause 5.6.6A(h) the clock has stopped for calculating the time the AER must make a determination.

While the Electricity Rules expressly provides for the AER to request information from the TNSP or the disputing party, the AER is not prohibited from requesting information from a party that is external to a dispute.

The AER may ask third parties to provide information voluntarily. The AER can also issue a notice under section 28 of the National Electricity Law (as discussed below).

Depending on the nature of the information from external parties, and the anticipated use to which the information will be put, the AER may allow the applicant and/or disputing party an opportunity to comment on the information.

Section 28 notice

Under section 28 of the National Electricity Law, the AER may issue a compulsory information gathering notice to require a person to provide information or produce documents which the AER requires for the performance or exercise of its functions and powers. The RIT-T dispute resolution process is one of the AER's functions.

A section 28 notice can require the person providing the information or producing documents within the time specified in the notice. The timeframe within which information must be provided is determined by the AER on a case by case basis. In the case of a RIT-T dispute, the notice will likely require that the information be provided within 14 *business days*.

Section 28(3) provides that a person must comply with a section 28 notice unless the person has a reasonable excuse. Under section 28(4) a person must not, in purported compliance with a relevant notice, provide information that the person knows is false or misleading in a material particular.

A breach of section 28 carries a penalty of up to $2000 (in the case of a natural person) or $10 000 (in the case of a body corporate).

Compliance with AER determination

A determination will generally take effect on the date that it is made by the AER and will specify a reasonable timeframe for the TNSP to comply with the AER's directions to amend the *project assessment conclusions report*.

Publishing a determination

The AER must publish its determination and its reasons for making a determination. The determination will be published on the AER's website and made available for public inspection at the AER's offices.

AER determination register

The AER intends to keep a public register of all determinations it makes.[12] Once a determination is published, it will be added to the AER determination register.

The disputing notice and all submissions (except those that are confidential) will be uploaded onto this register.

Merits review

The AER's RIT-T dispute resolution determinations are not subject to merits review.

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[12] This register will be located at the AER's website www.aer.gov.au.

5.4 Treatment of information

For information regarding the AER's use and disclosure of information see the ACCC/AER *Information Policy*, October 2008, which is available on the AER's website.

5.5 TNSP may request AER determination

Under clause 5.6.6AA where the *identified need* for a TNSP's *preferred option* is not *reliability corrective action*, the TNSP may request that the AER make a determination as to whether its *preferred option* satisfies the RIT-T.

Requirements for lodging the request

The request can only be lodged after the expiry of the 30 day period for disputing a *project assessment conclusions report* and must be in writing. The TNSP should also attach any information or reports which it considers may be relevant to the AER's determination. Relevant reports include (but are not limited to) the TNSP's *project specification consultation report*, the *project assessment draft report* and the *project assessment conclusions report*.

Timeframe for AER determination

Under the Electricity Rules the AER must make and publish a determination (including its reasons) within 120 *business days* of receiving the request. This period is automatically extended by the time taken by a TNSP to respond to a request from the AER for further information, provided:

- the AER makes the request for the additional information at least seven *business days* prior to the expiry of the period for making its determination, and

- the TNSP or disputing party provides the additional information within 14 *business days* of receipt of the request.

The determination will be published on the AER's website and made available for public inspection at the AER's offices.

Material the AER may consider

In making its determination the AER:

- must use the findings and recommendations in the *project assessment conclusions report* in making its determination

- may request further information from the TNSP, and

- may have regard to any other matter the AER considers relevant.

Other information which is likely to be relevant to the AER's consideration of the request includes any expert advice or reports on the proposed asset, any relevant planning publications and regulatory decisions relating to the proposed asset.

The AER may also engage an expert to provide advice. Such experts may include engineers, economists or experts in the electricity industry.

5.6 Cost determinations

Clause 5.6.6AA(d) of the Electricity Rules provides where the AER engages a consultant to assist in making a RIT-T dispute determination or a determination that a *preferred option* satisfies the RIT-T, the AER may make a costs determination. Costs determinations are limited to consultancy costs. Relevantly clause 5.6.6AA states:

> (e) Where a costs determination is made, the *AER* may:
>
> (1) render the *Transmission Network Service Provider* an invoice for the costs; or
>
> (2) determine that the costs should:
>
> (i) be shared by all the parties to the dispute, whether in the same proportion or differing proportions; or
>
> (ii) be borne by a party or parties to the dispute other than the *Transmission Network Service Provider* whether in the same proportion or differing proportions; and
>
> (iii) the *AER* may render invoices accordingly.
>
> (f) If an invoice is rendered, the *AER* must specify a time period for the payment of the invoice that is no later than 30 *business days* from the date the *AER* makes a determination under paragraph (d).

If a costs determination is made an invoice will be provided to the appropriate party. The invoice will set out a break down of the costs involved. Consistent with the requirements of the Electricity Rules, payment of the invoice will be required no later than 30 *business days* from the date of the AER's RIT-T dispute determination or a determination that a *preferred option* satisfies the RIT-T.

In making a cost determination, the AER has the discretion to determine the proportion of costs that each party should bear. Where the AER considers it appropriate that costs will be shared, the AER will take into account the circumstances and nature of the dispute to make its decision.

A. Guidance and worked examples on classes of market benefits

Clause 5.6.5B of the Electricity Rules requires the AER to provide guidance and worked examples on acceptable methodologies for valuing the *market benefits* of a *credible option*.

This attachment provides this guidance and worked examples on the following classes of *market benefits*:

- variable operating costs
- voluntary load curtailment
- involuntary load shedding
- costs to other parties
- timing of transmission investment
- network losses
- ancillary services costs
- competition benefits

Further guidance and worked examples on capturing option value in applying the RIT-T is set out in sections 3.2 and 3.6 of this application guideline.

A.1 Variable operating costs

A *credible option* may lead to a decrease, increase, or no material net change in the variable operating costs of supplying electricity to load. Variable operating costs include fuel consumption, ongoing legal and regulatory compliance costs (such as carbon costs) and variable maintenance costs. For simplicity, this note focuses on fuel costs.

First, a *credible option* may lead to a decrease in the cost of fuel consumed to supply electricity to load. For example, a *credible option* may:

- lead to a direct reduction in generation dispatch (typical for a demand-side reduction option), or
- facilitate the substitution of high-fuel cost plant with low-fuel cost plant (typical for a network option).

Either of these would constitute a positive contribution to the market benefits of the *credible option*.

Example 19 Decrease in fuel costs

Load is 200 MW. Local gas-fired generation has a fuel cost of $30/MWh and capacity of 100 MW. Remote coal-fired generation has a fuel cost of $10/MWh and capacity of 200 MW.

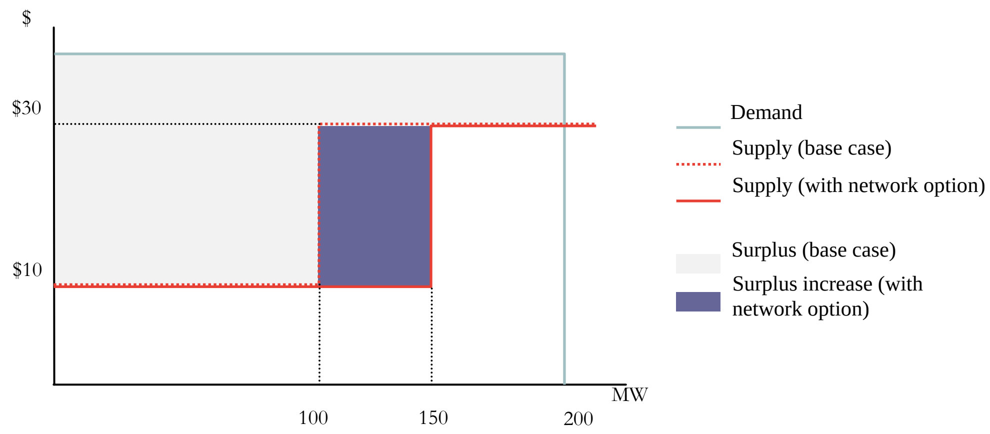
The capacity of the network between the remote generator and the load is limited to 100 MW whereas the capacity of the network between the local generator and the load is effectively unlimited.

The *credible option* is to augment the network between the remote generator and the load by 50 MW. This would reduce the fuel costs used in dispatch:

- from: $4,000 per hour (100 MW*$10+100 MW*$30)
- to: $3,000 per hour (150 MW*$10+50 MW*$30).

Assuming the same conditions over all 8,760 hours in a full year, the total fuel cost saving would be 8,760*$1,000 = $8,760,000 per annum. This would make a positive contribution to the market benefit of the network option.

Diagram 1 Decrease in fuel costs



Alternatively, a *credible option* may lead to an increase in the cost of fuel consumed to supply electricity to load. This may occur if, for example, the *credible option* is a local generator that is dispatched in a manner that leads to a reduction in unserved energy. However, the increase in fuel costs would constitute a negative contribution to the *market benefit* of the *credible option*.

Example 20 Increase in fuel costs

Load is 200 MW. Remote coal-fired generation has a fuel cost of $10/MWh and capacity of 200 MW. The capacity of the network between the remote generator and the load is limited to 150 MW.

The *credible option* is to build a 75 MW local gas-fired generator with a fuel cost of $30/MWh. This would increase the fuel costs used in dispatch:

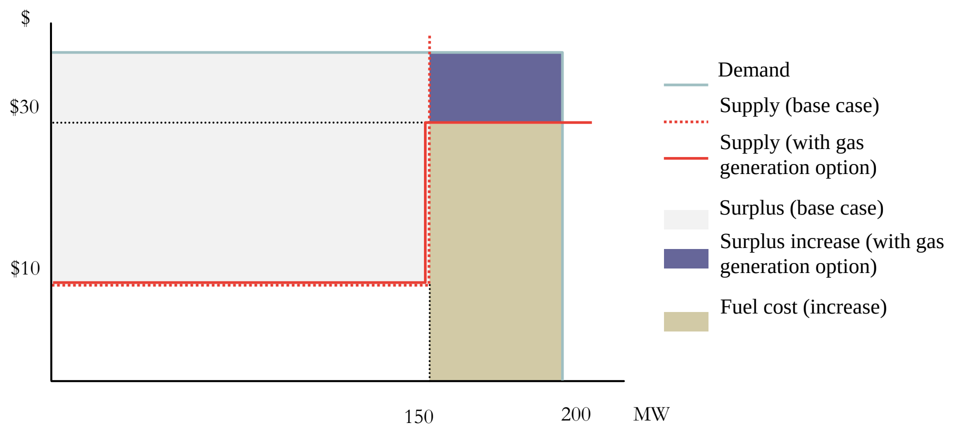
- from: 150 MW*$10 = $1,500 per hour

- to: 150 MW*$10 + 50MW*$30 = $3,000 per hour

In doing so, the *credible option* would reduce unserved energy by 50 MW.

Assuming the same conditions over all 8,760 hours in a full year, the total fuel cost increase would be 8,760*($3,000-$1,500) = $13,140,000 per annum. This would make a negative contribution to the market benefits of the local generation option.

Diagram 2 Increase in fuel costs



Finally, a *credible option* may have no material net impact on the cost of fuel consumed to supply electricity to load. For example, a network augmentation may both:

- facilitate the substitution of high-fuel cost plant by low-fuel cost plant (which reduces the cost of fuel consumed to supply electricity to load); as well as

- lead to a reduction in unserved energy (which increases the cost of fuel consumed to supply electricity to load).

Example 21 No change in fuel costs

Load is 200 MW. Local gas-fired generation has a fuel cost of $30/MWh and capacity of 75 MW. Remote coal-fired generation has a fuel cost of $10/MWh and capacity of 200 MW. The capacity of the network between the remote generator and the load is limited to 100 MW.

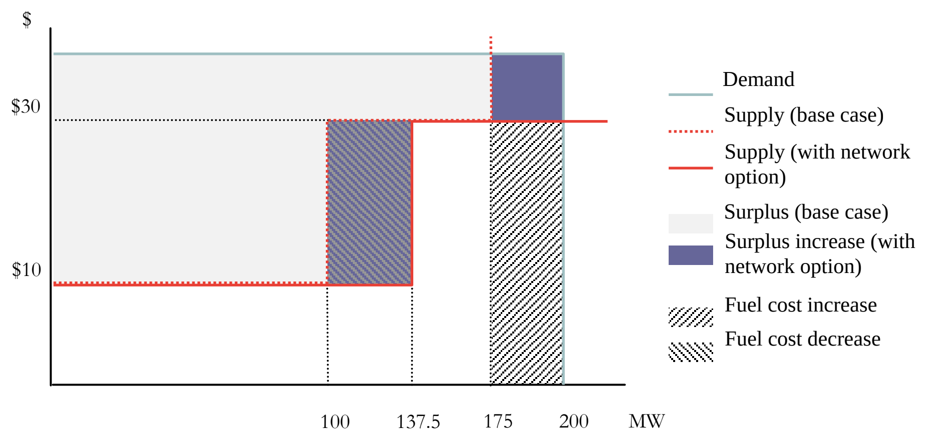
The *credible option* is to augment the network between the remote generator and the load by 37.5 MW. This would have the following effect on the fuel costs used in dispatch:

- from: 100 MW*$10 + 75 MW*$30 = $3,250 per hour

- to: 137.5 MW*$10 + 62.5 MW*$30 = $3,250 per hour.

The *credible option* in this case has reduced unserved energy by 25 MW (increasing fuel costs) while simultaneously displacing 12.5 MW of expensive local generation with cheap remote generation (decreasing fuel costs).

Diagram 3 No change in fuel costs



A.2 Voluntary load curtailment

A *credible option* may lead to a reduction in the amount of voluntary load curtailment. For example, a network option may, by facilitating the substitution of high-fuel cost plant with low-fuel cost plant, lead to a reduction in the spot price of electricity and consequently a reduction in voluntary load curtailment. This reduction in voluntary load curtailment can be valued as a market benefit by multiplying:

- the quantity (in MWh) of voluntary load curtailment not undertaken due to the *credible option*, by
- consumers' willingness to pay (in $/MWh) for the electricity that is not voluntarily curtailed due to the *credible option*.

This positive contribution to the market benefit of the *credible option* will be partly offset by a negative contribution to market benefit due to the costs of providing the additional electricity that is not voluntarily curtailed as a result of the *credible option* (see also the discussion of fuel consumption above).

Example 22 Decreased voluntary load curtailment

Load is 200 MW. Local gas-fired generation has a fuel cost of $30/MWh and capacity of 100 MW. Remote coal-fired generation has a fuel cost of $10/MWh and capacity of 250 MW.

The capacity of the network between the remote generator and the load is limited to 150 MW whereas the capacity of the network between the local generator and the load is effectively unlimited.

Voluntary load curtailment at a spot price of $30/MWh is 40 MW while voluntary load curtailment at a spot price of $10/MWh is 0 MW.

The *credible option* is to augment the network between the remote generator and the load by 50 MW. In the ***base case***:

- Demand = Load – voluntary load curtailment = 200 MW – 40 MW = 160 MW.
- The remote generator is dispatched to 150 MW and the local generator is dispatched to 10 MW.
- Spot price = $30/MWh (set by the local generator).
- Value of fuel consumed = 150 MW*$10 + 10 MW*$30 = $1,800 per hour.
- Value of voluntary load curtailment = 40 MW*$30/MWh = $1,200 per hour.

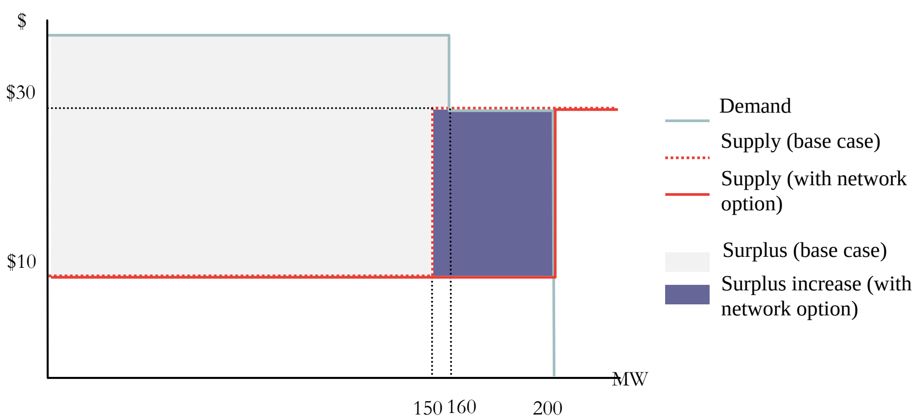
In the *state of the world* **with** the *credible option*:

- Demand = Load – voluntary load curtailment = 200 MW – 0 MW = 200 MW.
- The remote generator is dispatched to 200 MW and the local generator is dispatched to 0 MW.
- Spot price = $10/MWh (set by the remote generator).
- Value of fuel consumed = 200 MW*$10 + 0 MW*$30 = $2,000 per hour.
- Value of voluntary load curtailment = 0 MW*$10/MWh = $0 per hour.

Thus, the contribution to the market benefit of the *credible option* from a reduction in voluntary load curtailment is $1,200 - $0 = $1,200 per hour. This would be partly offset by the cost of increased fuel consumption of $2,000 - $1,800 = $200 per hour. The net impact on the market benefit of the *credible option* is $1,000 per hour.

Assuming the same conditions prevail for 100 hours in a year, the annual market benefit due to decreased voluntary load curtailment and the corresponding increased fuel consumption is 100*$1,000 = $100,000 per annum.

Diagram 4 Decreased voluntary load curtailment



Alternatively, a *credible option* (namely, a demand-side reduction option) may lead to an increase in the amount of voluntary load curtailment. This would make a negative contribution to the market benefits of the *credible option,* derived from:

- the quantity (in MWh) of voluntary load curtailment undertaken due to the *credible option*, multiplied by
- consumers' willingness to pay (in $/MWh) for the electricity that is voluntarily curtailed due to the *credible option*.

However, this negative contribution to the market benefits of the demand-side option should be **more than offset** by a positive contribution to market benefit caused by a reduction in the amount of involuntary load shedding that would otherwise occur (see Example 24 below).

The net contribution to the market benefits of the demand-side option would be derived from the difference between the value of unserved energy to consumers generally (e.g. $30,000/MWh) and the value of that energy to those consumers who have voluntarily agreed to consume less as a result of the demand-side option. For example, a demand-side option that led to voluntary load curtailment of 10 MWh of electricity valued by consumers at $30/MWh instead of involuntary load shedding of 10 MWh of electricity valued at $30,000/MWh would yield a positive contribution to market benefits of ($30,000-$30)*10 = $299,700.

A.3 Involuntary load shedding

A *credible option* may lead to a reduction in the amount of involuntary load shedding. This may occur if the *credible option* is:

- a local generation option that supplies electricity
- a demand-side reduction option that leads to voluntary load curtailment and thereby reduces demand for electricity, or
- a network option that enables electricity to be transported from a location where it is relatively plentiful to a location where it is relatively scarce, at times that involuntary load shedding would otherwise need to occur.

This reduction in involuntary load shedding can be valued as a market benefit by multiplying:

- the quantity (in MWh) of involuntary load shedding not required due to the *credible option*, by
- a reasonable forecast of the value of electricity to consumers (in $/MWh) not shed due to the *credible option*.

Examples of reasonable estimates of the value of electricity to consumers include:

- The market price cap (or Value of Lost Load, VoLL) – currently VoLL is $10,000/MWh but will increase to $12,500/MWh from 1 July 2010.

- The Value of Customer Reliability (VCR) used by AEMO for network planning purposes in Victoria. The VCR used by AEMO in the 2009 Victorian Annual Planning Report (VPAR) is $55,000/MWh.

This positive contribution to market benefits would be partially offset by a negative contribution due to the provision of the *credible option*. For example, a local generation option may reduce involuntary load shedding but will increase the use of fuel to supply electricity.

Example 23 Decreased involuntary load shedding

Load is 201 MW. Remote coal-fired generation has a fuel cost of $10/MWh and capacity of 250MW. The capacity of the network between the remote generator and the load is limited to 200 MW. Customers' value of involuntarily curtailed energy is $30,000/MWh.

The *credible option* is to build a 25 MW local gas-fired generator with a fuel cost of $100/MWh. In the ***base case***:

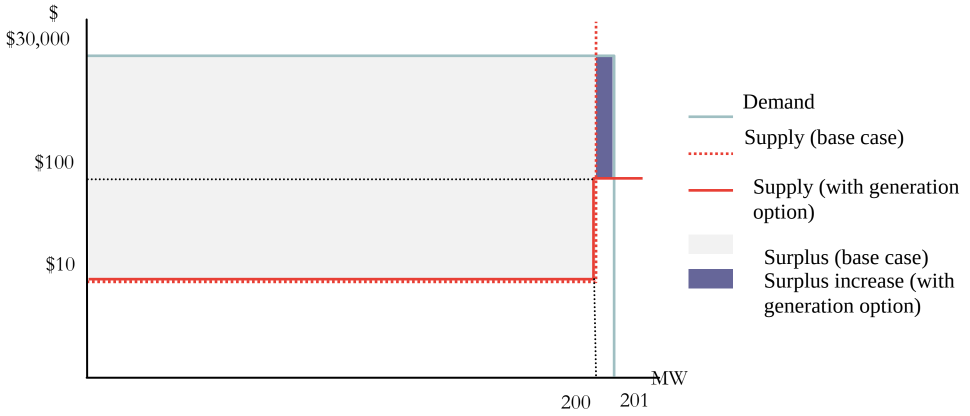
- Demand outstrips supply by 201 MW – 200 MW = 1 MW.
- Price is set at the value customers place on involuntarily curtailed energy, $30,000/MWh.
- Value of fuel consumed = 200 MW*$10 = $2,000 per hour.
- Value of involuntarily curtailed load = 1 MW*$30,000 = $30,000 per hour.

In the *state of the world* **with** the *credible option*:

- Output of remote generator = 200 MW and output of local generator = 1 MW.
- Price is set to $100/MWh by the local generator.
- Value of fuel consumed = 200 MW*$10 + 1 MW*$100 = $2,100 per hour.
- Demand = supply and hence there is no load shedding.

The contribution to the market benefits of the *credible option* from a reduction in involuntary load curtailment is $30,000 - $0 = $30,000. This would be partly offset by the cost of increased fuel consumption needed to generate electricity which is $2,100 - $2,000 = $100 per hour. The net contribution to the market benefits of the *credible option* (in terms of decreased involuntary load curtailment and increased fuel consumption) is thus $29,900 per hour. Assuming the same conditions over 10 hours in a year, the total contribution to the market benefits of the *credible option* is 10*$29,900 = $299,000 per annum.

Diagram 5 Decreased involuntary load shedding



As noted above, a demand-side reduction option may simultaneously have a negative contribution to market benefit due to an increase in voluntary load curtailment as well as a positive contribution to market benefit due to a decrease in involuntary load shedding. However, the net effect on market benefit would almost always be positive, as electricity will usually be worth more to those who are involuntarily curtailed than to those who are voluntarily curtailed.

Example 24 Increased voluntary and decreased involuntary load curtailment

Load is 201 MW. Remote coal-fired generation has a fuel cost of $10/MWh and capacity of 250 MW. The capacity of the network between the remote generator and the load is limited to 200 MW. In the event demand outstrips supply load is involuntarily curtailed (load shedding). Customers value involuntarily curtailed energy at $30,000/MWh.

The *credible option* is a demand side management scheme whereby commercial customers agree with a retailer to reduce power demand by 1 MW when requested by the retailer. This will occur when the retailer expects that the spot price would exceed $1,000/MWh in the absence of load curtailment. The $1,000/MWh price reflects the retailer's view of its commercial customers' underlying willingness to pay for electricity.

In the ***base case***:

- Demand outstrips supply by 201 MW – 200 MW = 1 MW.
- Price is set at the value customers place on involuntarily curtailed load ($30,000/MWh) and 1 MW of load is involuntarily curtailed to ensure demand = supply.
- Value of voluntary load curtailment = 0 MW*$1,000 = $0 per hour.

- Value of involuntary load curtailment = 1 MW*$30,000 = $30,000 per hour.

In the *state of the world* **with** the *credible option*:

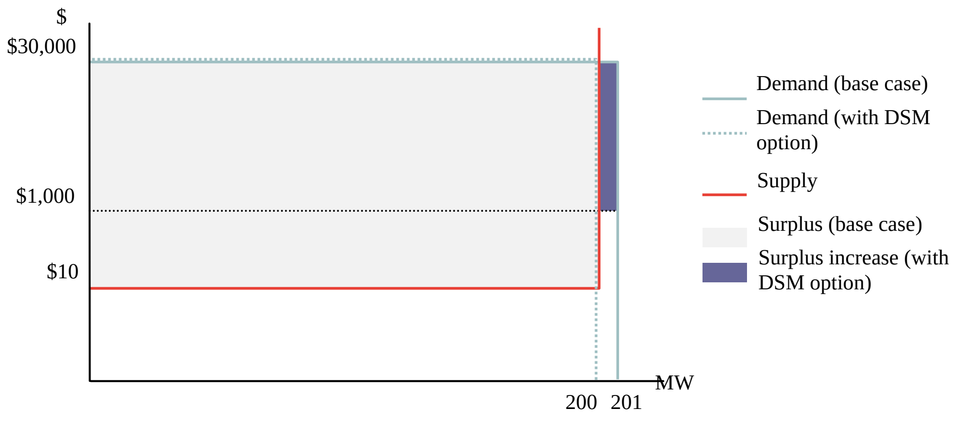
- Demand = load – voluntary load curtailment = 201MW – 1MW = 200 MW.
- Price is set by the remote generator at $10/MWh.
- Voluntary load curtailment under the *credible option* and at a price of $10/MWh is 1 MW.
- Demand = supply and there is no load shedding.
- Value of voluntary load curtailment = 1 MW*$1000 = $1,000 per hour.

The market benefit of the *credible option* arising from the demand side option is:

- benefit of decreased involuntary load curtailment = $30,000 - $0 = $30,000 less
- benefit of increased voluntary load curtailment = $1,000 - $0 = $1,000.

The combined contribution to the market benefits of the *credible option* (in terms of increased voluntary and decreased involuntary load curtailment) is thus $29,000 per hour. Assuming the same conditions over 10 hours in a year, the total contribution to the market benefits of the *credible option* would be 10*$29,000 = $290,000 per annum.

Diagram 6 Increased voluntary and decreased involuntary load curtailment



A.4 Costs to other parties

This class of costs captures the impact of a *credible option* on the plant expansion path of the market.

To the extent that a *credible option* leads to a delay in the commissioning of a new plant (which reduces the present value of the resource costs incurred to meet demand), or to other reductions to other parties' costs, this represents a positive *market benefit* of the option. The reverse is also the case.

Example 25 Delaying plant commissioning

The *credible option* is the development of a 1000 MW interconnection. The development of this interconnection will delay the need for a 450 MW mid-merit gas plant by 3 years. Without the interconnection the gas plant would be developed immediately (t = 0). With the interconnection, the gas plant would be developed in three years (t = 3). The mid-merit gas plant has a total capital cost of $500m. The discount rate is 7 per cent.

Based on the above assumptions, the positive contribution to the *market benefits* of the interconnection option due to the delayed commissioning of the mid-merit gas plant (in terms of delaying capital costs only) can be calculated as follows:

- Present value of the mid-merit gas plant's capital costs in the ***base case***:

$$PV = \frac{\$500m}{(1.07)^0} = \$500m$$

- Present value of the mid-merit gas plant's capital costs **with** the *credible option*:

$$PV = \frac{\$500m}{(1.07)^3} = \$408m$$

The positive contribution to the market benefits of the *credible option* due to the delayed commissioning of the mid-merit gas plant is $500m - $408m = $92m.

Example 26 Delaying and accelerating plant commissioning

The following example builds on Example 25.

In addition to delaying the need for a mid-merit gas plant, the *credible option* also leads to the bringing forward of a 450 MW baseload plant in the exporting *region.* In the *base case*, the mid-merit gas plant would be developed immediately (t = 0), while the baseload plant would be developed in three years (t = 3). With the *credible option*, the mid-merit gas plant would be developed in three years (t = 3) while the baseload plant would be developed in two years (t = 2). The baseload plant has a capital cost of $600m.

Based on the above assumptions, the negative contribution to the market benefits of the *credible option* due to the accelerated commissioning of the baseload plant (in terms of bringing forward capital costs only) is calculated as follows:

- Present value of the baseload plant's capital costs in the ***base case***:

$$PV = \frac{\$600m}{(1.07)^3} = \$490m$$

- Present value of the baseload plant's capital costs **with** the *credible option*:

$$PV = \frac{\$600m}{(1.07)^2} = \$524m$$

The negative contribution to the market benefits of the *credible option* due to the bringing forward of the commissioning of the baseload plant is \$524m - \$490m = \$34m.

The combined contribution to the market benefits of the *credible option* due to (i) the delaying of the mid-merit gas plant and (ii) the bringing-forward of the baseload plant is \$92m - \$34m = \$58m.

A.5 Timing of transmission investment

A *credible option* may change the timing (or the configuration) of other investments to be made by (or for) the TNSP in the future.

As noted above, the market benefits of all *credible options* need to be derived by comparison against a common *base case* (although the *base case* will vary across the relevant *reasonable scenario* under consideration). The development of the required *states of the world* and *reasonable scenarios* is discussed in section 3.5.

Also noted in the RIT-T, the *base case* is a *state of the world* without any *credible option* in place. Under the Electricity Rules and the RIT-T, a *credible option* is an option (or group of options) that, among other things, addresses an *identified need*.

This means that the *transmission investments* that are the subject of clause 5.6.5B(c)(4)(v) should not be those that have the same *identified need* as the set of *credible options* under consideration. Any *transmission investments* that are directed towards the same *identified need* as a particular *credible option* should themselves be viewed as *credible options* (or elements of *credible options*) and excluded from the *base case*.

Therefore, the only *transmission investments* whose changes in timing should be taken into account in applying the RIT-T are those directed towards *identified needs* different to those that the *credible option* is directed towards. It is not clear whether or how many investments this category could or would include.

A.6 Network losses

A *credible option* may lead to a net increase or decrease in network losses. An increase in network losses makes a negative contribution to the market benefits of a *credible option* while a decrease in network losses makes a positive contribution to the market benefits of a *credible option*.

Example 27 Decreased network losses

Load is 500 MW. Remote coal-fired generation has a fuel cost of \$10/MWh and capacity of 750 MW. The capacity of the network link between the remote coal-fired generator and the load is limited to 600 MW.

The *credible option* is the augmentation of the network link between the remote coal-fired generator and the load. The augmentation will involve upgrading the transmission link from a 220 kV to a 400 kV line. This augmentation is expected to reduce transmission losses from 10 per cent to 5 per cent when operating at 500 MW.

In the ***base case***:

- Price is $10/MWh set by the remote coal-fired generator
- Total losses = $10*0.1*500 MW = $500 per hour.

In the *state of the world* **with** the *credible option*:

- Price is $10/MWh, set by the remote coal-fired generation.
- Total losses = $10*0.05*500 MW = $250 per hour.

Assuming the same conditions over 8,760 hours per year the contribution of decreased network losses to the market benefit of the *credible option* is ($500 - $250)*8,760 = $2,190,000 per year.

A.7 Ancillary services costs

A *credible option* may lead to a net increase or decrease in *ancillary services* costs. An increase in *ancillary services* costs makes a negative contribution to the market benefits of a *credible option* while a decrease in *ancillary services* costs makes a positive contribution to the market benefits of a *credible option*.

Example 28 Increased ancillary services costs

Load is 300 MW and is flat (i.e. is equal to 300 MW) for all hours of the year. Average *network control ancillary services* costs across the year are $0.35/MWh.

The *credible option* is the development of a network element to help stabilise voltage. This is expected to reduce average *network control ancillary services* costs to $0.20/MWh.

In the ***base case***:

- Total *ancillary services* costs are $0.35*8,760*300 MW = $919,800 per year.

In the state of the world **with** the *credible option*:

- Total *ancillary services* costs are $0.20*8,760*300 MW = $525,600 per year.

Assuming load is flat at 300 MW for all hours of the year, the contribution of reduced *ancillary services* costs to the market benefits of the *credible option* is $918,800 - $525,600 = $394,200 per year.

A.8 Competition benefits

Clause 5.6.5B(c)(4)(viii) of the Electricity Rules requires a TNSP conducting the RIT-T to consider competition benefits as a class of potential market benefits that could be provided by a *credible option*.

The identity and description of competition benefits was discussed extensively in the ACCC's 2004 Regulatory Test Decision including in Appendices C, D and E by Dr Darryl Biggar.

As discussed in that decision, and as set out below, the computation of the market benefits of a *credible option* in a given *reasonable scenario* **includes** competition benefits where the modelling process explicitly takes into account the likely impact of the *credible option* on the bidding behaviour of generators (and other market participants) who may have a degree of market power relative to the *base case*. A market participant has a degree of market power in a given dispatch interval if it can, by varying its bid or offer, alter the pricing, dispatch and flow outcomes in the market (including possibly inducing 'clamping') in that dispatch interval in a manner that is profitable for that firm.

Paragraph 16(h)(i) of the RIT-T requires a TNSP to apply competitive (short-run marginal cost or SRMC) bidding and provides for approximates of 'realistic' bidding approaches to be used as a reasonable scenario. Where realistic bidding is used to consider the effects of a *credible option*, the measured change in overall economic surplus will, **by implication**, include competition benefits.

To be precise, the computation of the market benefits of a *credible option* in a given *reasonable scenario* **will automatically include** competition benefits where the modelling process calculates market benefits as the difference between the present value of:

- the overall economic surplus arising with the *credible option*, with bidding behaviour reflecting any market power prevailing with that option in place, and
- the overall economic surplus in the *base case*, with bidding behaviour reflecting any market power in the *base case*.

The Appendices to the 2004 Regulatory Test Decision suggested two possible methodologies for identifying that component of market benefits which is attributable to competition benefits:

- the methodology suggested by Dr Biggar, which involved finding the difference between:
  - the overall economic surplus arising in a network with the *credible option*, with the bidding behaviour of market participants reflecting any market power they have in a network with that option in place, and
  - the overall economic surplus arising in a network with the *credible option*, with the bidding behaviour of market participants reflecting any market power they have in the *base case* network.

This methodology requires a modelling process which allows the bidding behaviour to be 'held constant' while the underlying network is changed.

- the methodology suggested by Frontier Economics, which involved finding the difference between:
  - the change in overall economic surplus resulting from the *credible option* assuming bidding reflected the prevailing degree of market power both before and after the augmentation, and
  - the change in overall economic surplus resulting from the *credible option* assuming competitive bidding both before and after the augmentation.

Examples of both of these methodologies are provided below.

To be clear, both of these approaches involve the same methodology for the calculation of the overall *market benefits* of a *credible option*. The difference between the two approaches is in how the overall *market benefits* of a *credible option* are divided between competition benefits and other benefits (also referred to as 'efficiency benefits').

Both of these approaches have certain merits. Dr Biggar considered that his approach yielded a more intuitive economic interpretation to competition benefits than Frontier Economics' approach. However, he noted that Frontier Economics' approach meant that its measure of efficiency benefits was directly comparable to the definition of market benefits in previous applications under the regulatory test.

A TNSP is free to adopt either approach or another approach of their choosing in calculating competition benefits and the RIT-T reflects this intention. However, it is important that there is no double-counting of the competition benefits of a *credible option*.

The key requirement in calculating competition benefits is a robust approach to the methodology for determining 'realistic' bidding behaviour. The AER does not wish to prescribe the methodology for determining realistic bidding behaviour other than to suggest that it should:

- be based on a credible theory as to how participants are likely to behave in the wholesale spot market over the modelling period, and
- take into account the impacts of other participants' behaviour on the bidding behaviour of any given participant.

Example 29 Competition benefits – Biggar approach

The following example draws on Biggar (2004).[13]

[13] D Biggar, *Calculating competition benefits: a two town example*, Appendix D to ACCC, *Decision of the review of the regulatory test for network augmentations*, August 2004, p. 99.

- Load is 200 MW
- There are three generators capable of serving this load:
  - coal-fired generation with a short-run marginal cost (SRMC) of $10/MWh and capacity of 120 MW
  - mid-merit gas-fired generation with a SRMC of $50/MWh and capacity of 100 MW
  - peaking oil-fired generation with a SRMC of $100/MWh and capacity of 40 MW
- The *credible option* in question is the development of an interconnector with a capacity of 140 MW to a competitive *region* that supplies electricity at a constant SRMC of $12/MWh.
- Assume that the coal-fired generator behaves strategically so as to maximise its short-run profit, given by: Qty*(Price-SRMC).
- Further assume the coal-fired generator, due to technical requirements, has a minimum generation level of 60 MW and must offer its capacity in increments of 10 MW.
- Finally assume that all other generators (including the power supplied through the interconnector) behave competitively – i.e. they bid their full capacity into the market at SRMC.

In the ***base case***:

- The three generators in the *region* make the following offers:
  - coal-fired generation offers 90 MW at $10/MWh[14]
  - mid-merit gas-fired generation offers 100 MW at $50/MWh
  - peaking oil-fired generation offers 40 MW at $100/MWh.
- Market price is $100/MWh set by the peaking generator.
- Total dispatch costs are 90*$10 + 100*$50 + 10*$100 = $6,900 per hour

In the *state of the world* **with** the *credible option*:

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[14] This maximises the incumbent coal-fired generators short-run profit at 90*(100-10) = $8 100 per hour. Offering 100MW yields 100*(50-10) = $4000 per hour. Offering 80MW yields 80*(100-10) = $7200 per hour. Offering 60MW (minimum offer) yields 60*(100-10) = $5400 per hour.

[15] This maximises the incumbent coal-fired generators short-run profit at 120*(12-10) = $240 per hour. Offering 110MW yields 110*(12-10) = $220 per hour. Offering 60 MW (minimum offer) yields 60*(12-10)=$120 per hour.

- The interconnector enables the supply of 140 MW of electricity at $12/MWh.

- The generators in the *region* make the following offers:

  - coal-fired generation offers 120 MW at $10/MWh[15]

  - mid-merit gas-fired generation offers 100 MW at $50/MWh

  - peaking oil-fired generation offers 40 MW at $100/MWh.

- Market price is $12/MWh set by the marginal generator in the adjacent *region* through the interconnector.

- Total dispatch costs are 120*$10 + 80*$12 = $2,160 per hour.

- The Biggar approach calculates the competition benefit of a *credible option* as the difference between the total dispatch cost:

  - in a *state of the world* **with** the *credible option* and assuming participants bid strategically in a manner that reflects any market power they have in the presence of the *credible option*, and

  - in a *state of the world* **with** the *credible option* but assuming that participants bid as they did in a state of the world **without** the *credible option* (that is, the *base case*).

- Based on the above data, the total dispatch cost in a *state of the world* with the *credible option* and assuming participants bid strategically is:

Dispatch cost = (120 * $10 + 80 * $12) = $2160 per hour

- The total dispatch cost in a *state of the world* **with** the *credible option* and assuming participants bid as they did in a *state of the world* **without** the *credible option* (that is, the *base case*) is:

(90 * $10 + 110 * $12) = $2220 per hour

- The competition benefit is thus:

$2220 – $2160 = $60 per hour

- The total benefit is $6,900 – $2,160 = $4,740 per hour. This implies that the efficiency benefit is $4,740 - $60 = $4,680.

Example 30 The Frontier approach to calculating competition benefits

The following example is based on the data used in Example 29:

- The Frontier approach calculates the competition benefit of a *credible option* as the difference between:

- the change in the total dispatch cost between *states of the world* with and without the *credible option*, assuming competitive bidding in both *states of the world*
- the change in the total dispatch cost between *states of the world* with and without the *credible option*, assuming strategic bidding in both *states of the world*.

- Based on Example 29, the change in the total dispatch cost between *states of the world* **with** and **without** the *credible option*, assuming competitive bidding in both *states of the world* is:

(120 * $10 + 80 * $50) – (120 * $10 + 80 * $12) = $3040 per hour

- The change in the total dispatch cost between a *state of the world* with and without the *credible option*, assuming strategic bidding in both *states of the world* is:

(90 * $10 + 100 * $50 + 10 * $100) –(120 * $10 + 80 * $12) = $4740 per hour

- The competition benefit is thus:

$4740 – $3040 = $1700 per hour

- The total benefit is the change in total dispatch costs between *states of the world* with and without the *credible option*, assuming strategic bidding. From above, this is $4,740 which is the same as under the Biggar approach. This implies that the efficiency benefit is $4,740 - $1,700 = $3,040. This is equivalent to the change in total dispatch costs between *states of the world* with and without the *credible option*, assuming competitive bidding in both *states of the world*.

The regulatory test (version three) allows for TNSPs to include *market benefits* from overcoming ‘disorderly’ bidding through sensitivity testing. Paragraph 16 of the RIT-T allows a TNSP to model the effect of ‘realistic’ generator bidding behaviour. Realistic bidding in this context could include disorderly bidding, where appropriate. Therefore, to the extent a *credible option* attenuates the incentives for a generator to engage in disorderly bidding, the calculation of that *credible option*’s *market benefit* could include the *market benefit* arising from more cost-reflective generator bidding. However, modelling disorderly bidding behaviour is difficult and may not be warranted in the majority of RIT-T assessments.

A.9 Option value

Clause 5.6.5B(c)(4)(ix) of the Electricity Rules requires a TNSP applying the RIT-T to consider option value as a class of potential market benefits that could be provided by a credible option.

Option value refers to a benefit that results from retaining flexibility in a context in which certain actions are irreversible (sunk), and new information may arise in the future as to the payoff from taking a certain action.

The AER believes that appropriate identification of credible options captures any option value, thereby meeting the Rule requirement to consider option value as a class of market benefit under the RIT-T. This is discussed further, and worked examples provided in sections 3.2 and 3.6.

Glossary

anticipated project	has the meaning set out in the RIT-T.
application guidelines or guidelines	means the *regulatory investment test for transmission application guidelines* defined in the Electricity Rules.
base case	has the meaning set out in the RIT-T.
committed project	has the meaning set out in the RIT-T.
cost	has the meaning set out in the RIT-T.
market benefit	The term market benefit (not italicised) refers to the incremental benefit of a *credible option* (over the *base case*) **in a given *reasonable scenario***. The term *market benefit* (italicised) has the meaning set out in the RIT-T.
modelled project	has the meaning set out in the RIT-T.
Electricity Rules	the rules as defined in the National Electricity Law.
reasonable scenarios	has the meaning set out in the RIT-T.
RIT-T	the *regulatory investment test for transmission* defined in the Electricity Rules.
state of the world	has the meaning set out in the RIT-T.