17 The Regulatory Investment Test for Transmission

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| Key points |
| * The Regulatory Investment Test for Transmission (RIT‑T) is a cost-benefit test that is performed before major new transmission projects are commenced. It does not dictate revenue allowed for particular projects. While a useful tool, it has some shortcomings. * There is inevitably scope for those conducting any cost–benefit test to influence the outcome. At present, there is no independent approval of the RIT‑T. Therefore, the party that performs the test can have financial incentives to achieve a particular outcome. * There is a need for increased involvement from independent parties. * In line with its recommendations for transmission planning, the Commission recommends an enhanced process and new role for the RIT‑T. * All projects (both augmentations and replacements) above a threshold value would be subject to a revised RIT‑T, and a contingent project based determination for the revenue for that project. This threshold would be indexed over time to maintain its real value. * The RIT‑T documentation would become the business’s revenue proposal. * The AER (Australian Energy Regulator) would assess the merits of the RIT‑T (as well as the process). * Once approved by the AER, revenue for the allowed sum could be recovered through network charges. At the next regulatory determination, the actual capital spent would be rolled into the regulatory asset base. * Taking on this new role necessitates changes to the RIT‑T process. * Transmission businesses would remain responsible for conducting the test, with AEMO (Australian Energy Market Operator) conducting a parallel analysis. * The AER would effectively approve the RIT‑T through the ‘contingent projects’ process. AEMO’s advice would be presumed to apply, unless the transmission business could provide convincing alternative evidence. * The RIT‑T would become a full cost-benefit analysis, including updating probabilistic reliability standards as part of the overall benefit calculations. * The current test only allows consideration of costs and benefits that accrue to those who produce, consume or transport electricity. There are both theoretical and pragmatic reasons for not expanding this to include costs and benefits to other parties. |
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Incentive regulation of Transmission Network Service Providers (TNSPs) (chapter 5), the reliability standards with which they must comply and the broader transmission planning process (chapter 16) are the major drivers of TNSP investment decisions. However, there is another regulatory process that can influence the choice of transmission projects — the Regulatory Investment Test for Transmission (RIT‑T), which is a cost–benefit test applied to specific major transmission projects.

In concert with transmission planning, the goal of the RIT‑T is to identify the most beneficial options for future transmission investment. While such a succinct aspirational statement may seem simple, it belies several complexities. Beneficial to whom? Which benefits can be counted, and how? As the subsequent discussion illustrates, such considerations are highly relevant in assessing the contribution that the RIT‑T currently makes towards achieving efficient levels of transmission and interconnector investment in the National Electricity Market (NEM).

Importantly, a revised transmission planning framework (chapter 16) brings with it a new role for the RIT‑T.

## 17.1 The current framework

The RIT‑T is a cost–benefit process that is done before all major new transmission projects, including interconnectors, are undertaken.[[1]](#footnote-1) It is not required if a transmission asset is being replaced, rather than augmented.

In attempting to replicate investment outcomes that would arise in a competitive market environment, the RIT‑T aims to: quantify the costs and benefits that accrue to those who consume, transport or generate electricity as the result of a new project; and to ensure that only projects with the highest net present value proceed.[[2]](#footnote-2) In doing so, it includes several categories of costs and benefits (box 17.1).

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| Box 17.1 The costs and benefits in a RIT‑T under the current system |
| For any proposed new investment, the party performing the RIT‑T compiles a list of options. These options can be network options, or alternatives such as demand management or a new generator. At this stage of the process, interested parties can raise alternatives that must be considered, or a rationale given for their exclusion.  Once a list of options is finalised, the expected benefit of each project is calculated using the costs and benefit categories described in the RIT‑T documentation.  The costs that can be included are:   * the costs of construction or providing the options * operating and maintenance costs * cost of complying with laws and regulations * any other reasonable costs that are agreed to by the AER.   The benefits considered under the RIT‑T include:   * decreased fuel dispatch * changes in voluntary load curtailment (users reducing consumption for a price) * reductions in involuntary load shedding (when electricity supply is cut off to parts of the network to maintain system security) * changes in cost to other parties, such as the deferral of a new plant * differences in the timing of other transmission projects * changes in network losses or in ancillary services costs * competition benefits * option value (the benefit from retaining flexibility by taking a sunk action, such as reserving property rights, whose value could change in the future) * adjustments for helping to meet the Renewable Energy Target.   These costs and benefits are calculated in a number of forecast scenarios, and assigned a weight for the probability that each scenario will occur. The project with the highest, probability‑weighted, net present value is chosen by the TNSP for development (if the project is ‘reliability driven’ this value may be negative).Throughout the RIT‑T process, the regulator only plays a role in monitoring issues of process, such as not following the consultation guidelines, and plays no active role in approving the RIT‑T outcomes. Indeed, despite the name, this is not a test that the regulator is involved in ‘marking’. In reality, it is ‘due diligence’ by the TNSP, undertaken prior to an investment and carried out with some public involvement and transparency. |
| *Source*: AER (2010e). |
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The RIT‑T gives equal consideration to the interests of those who consume, produce and transport electricity. In effect, this is an efficiency test, and will give no weight to any redistributive outcome of an investment. To a large degree, decisions made under this rule will align with the overarching National Electricity Objective (NEO) as they will generally direct investment in the *long‑term* interests of consumers. (As noted in chapter 3, the NEO can also be seen as fundamentally an efficiency objective.) It is important to recognise that the RIT‑T is just the most recent form of regulatory test applied to transmission, and previous versions of the test did consider some issues of distribution (box 17.2).

The primary goal of the RIT‑T is to identify both the most efficient transmission projects, and any more efficient (non‑network) options, such as demand management, where they exist. However, the RIT‑T itself does not determine the revenue allocated for a particular project. Instead, it is part of a broader regulatory process in which the building block process, incentive regulation and the longer‑term planning processes all play a role in promoting efficient investment decisions.

It is therefore important to consider the design of the RIT‑T as part of the overall regulatory process. If other parts of the regulatory system are working well and providing appropriate incentives to deliver an efficiently reliable, low cost network, the RIT‑T would be less important. But if the regulatory system is providing weak incentives, the RIT‑T will play a more important role in directing efficient investment.

Where reliability standards are set deterministically, a profit motivated TNSP has incentives to achieve these standards at least cost (regardless of whether a RIT‑T is undertaken or not). At best, the reassuringly named ‘regulatory investment test’ may substantiate that the TNSP has selected the available option with the highest net benefits, given the deterministic constraints, but it cannot alter the inefficiency of those constraints.

Aside from the main goal of identifying the most efficient new investments, the RIT‑T also performs several secondary, but still valuable roles. These include a (mandatory) consultation process to allow parties with relevant information, such as suggested alternative solutions, for a particular investment to come forward.[[3]](#footnote-3) For example, a generator announcing that it was planning to commission a new plant in an area could make a network augmentation unnecessary.

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| Box 17.2 A brief history of regulatory tests |
| The RIT‑T is a relatively new process, and has only applied to transmission assessments initiated since 1 August 2010. A full RIT‑T process is yet to be completed. Some have argued that, in the name of regulatory certainty the recent introduction of the RIT‑T might militate against reforms to it at this juncture.  However, the RIT‑T is in fact the result of an evolving process for the assessment of new transmission projects that began with the consumer benefits test included in the National Electricity Code prior to 1999 (AER 2009f, p. 3). As the name suggests, this test was based on whether the project represented a net gain for consumers of electricity.  As it transpired, application of this test proved to be problematic, especially if a project offered the prospect of a gain for consumers but imposed more than offsetting costs on other parties. After the rejection of a proposed South Australia–New South Wales interconnector, the National Energy Market Management Company Limited found that the customer benefits test was ‘highly volatile’ (ACCC 1999).[[4]](#footnote-4)  The first regulatory test was introduced in 1999 by the Australian Competition and Consumer Commission and required the test to examine a net market benefit as the RIT‑T does now. Versions 2 (AER 2004) and 3 (AER 2007b) expanded on the cost–benefit framework and clarified some areas of uncertainty in its implementation.  The main changes to the process introduced with the RIT‑T in 2010 were the requirement to do a cost–benefit test for projects performed for reliability reasons, rather than providing them at the lowest overall cost, and the introduction of new consultation requirements. The RIT‑T is also more prescriptive in how to calculate costs and benefits (AER 2010f, p. 2). |
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The RIT‑T also provides a platform for public debate around a particular transmission investment and provides transparency around the calculations used in coming to investment decisions. Importantly, the RIT‑T does not involve the regulator approving (or vetoing) particular investment options.

Moreover, the test is a cost–benefit analysis and, like all calculations of its type, it will require assumptions, simplifications and, in some cases, decisions about whether to include entire classes of benefits. Analysis is costly, and the goal of the RIT‑T is to find the best project, not to attempt to produce the perfect estimate of the net benefit of any particular option.

## 17.2 Issues with the current RIT‑T

As identified in chapter 16 (box 16.2), and above, there are several issues with the broad functioning of the RIT‑T in its current form. Principally, these relate to the responsibility for the conduct and ‘approval’ of the test, the incentives provided (particularly in relation to projects identified as necessary on reliability grounds), and the consequences arising from the performance and outcome of the test.

### Responsibility for performing and ‘approving’ the RIT‑T

Despite its name, the RIT‑T is not performed or ‘marked’ by a regulator. Instead, it is undertaken by the entity with responsibility for transmission planning in each jurisdiction.

Consequently, in New South Wales, South Australia, Tasmania and Queensland, the relevant transmission business performs the test, with the limited oversight provided by the Australian Energy Regulator (AER) focused only on matters of process, rather than assessing (or approving) the TNSPs’ analysis. The TNSP is also responsible for arranging the construction of a new asset if the RIT‑T finds it to be the available option with the highest net benefits. As such, there is no independent assessment of the merits of the RIT‑T.[[5]](#footnote-5) Some participants argued that there were sufficient controls, and oversight by outside parties, to ensure that the RIT‑T would be applied appropriately by TNSPs:

… the RIT‑T is a highly prescribed test that is conducted with oversight by interested stakeholders and the AER. This oversight is also strengthened through the AEMC’s [Economic Rule Change] proposals. While the current formulation of the test is still relatively new, there is no reason to suggest that this test will not be applied as prescribed and in good faith. (Grid Australia, sub. DR91, p. 33)

In Victoria, the RIT‑T is performed by the Australian Energy Market Operator (AEMO) as part of its planning function and the favoured option is constructed and ultimately owned by either the incumbent TNSP or a different party. Small projects, or projects that are unable to be separated from the network, are provided by the incumbent TNSP (SP AusNet) for a negotiated fee. For larger projects that can be separated from the network, a tendering process is employed and the incumbent TNSP, as well as others, can bid for the right to construct, operate and own the augmentation. While TNSPs in other jurisdictions, and AEMO in Victoria, all conduct a RIT‑T, outcomes in Victoria can be markedly different, as:

* AEMO also conducts a (broader) cost–benefit analysis in the course of its own planning process
* AEMO applies probabilistic reliability standards, meaning that projects must pass a cost–benefit analysis, in contrast to the existing special treatment for reliability under the RIT‑T (below), and
* having an independent party (other than the TNSP) responsible for performing a cost–benefit analysis and the RIT‑T (including consultation processes), and effectively approving its outcome, changes the role and nature of the RIT‑T.

Cost–benefit analysis of any complex future action is never an exact science. In estimating the costs and benefits of a new project it is necessary to make a number of assumptions. While some of these are specified in the RIT‑T framework, others are necessarily left to the discretion of the party performing the test. Some important assumptions that affect the viability of future projects include:

* demand forecasts
* cost estimates of future projects
* the weighting and detailed application of future scenarios[[6]](#footnote-6)
* the extent to which other projects (including generation assets) will be delayed if a particular option is chosen
* the value of improved reliability to customers
* the costs and benefits of alternative options (including those posed by third parties). Notably, this can include the relative risks, particularly to the stability of the network, of various options.

Under the current framework, TNSPs undertaking the analysis can have a financial incentive to favour a particular outcome. The presence of financial rewards or penalties in the incentive regulation regime (chapter 5), as well as additional objectives brought to bear on government‑owned TNSPs (chapter 7) could drive a TNSP to favour investment options that may not necessarily be optimal from the perspective of an efficiently‑operated NEM. For example, in certain circumstances, a transmission business may wish, for commercial reasons, to delay or bring forward expenditure. It may also wish to select network options over non‑network options, or favour an intra‑state option over an interstate option. Such incentives may, consciously or unconsciously, reduce the impartiality of consideration of all options and thus diminish the capacity of the RIT‑T to effectively perform its intended role.

On the other hand, it could be argued that this type of commercial influence on RIT‑Ts may be muted in practice, as RIT‑Ts are often performed in a separate part of the transmission business, and can be outsourced to external parties. In these circumstances, it is conceivable that the detailed application of the test could occur in more of an arms‑length fashion than might appear to be the case. Further, the detailed local knowledge and experience possessed by TNSPs could mean that they are aware of particular advantages and disadvantages of options that may not appear obvious to a third party — this could include familiarity with local planning requirements, local geography as it effects construction options and costs, and pre‑existing relationships with both regulators and prospective tenderers.

Nonetheless, the conflict of interest arising from those with a financial interest both conducting the test and approving the outcome, whether real or perceived, remains. Thus, in the Commission’s opinion, some improvements to the transparency and oversight of the RIT-T, and the disciplines on TNSPs in conducting the test, are warranted.

#### Information asymmetries

In their roles as network service providers (and planners), TNSPs possess detailed information of their own network and the power that flows through it. While the current RIT‑T (as well as TNSP annual planning reports) brings some level of transparency, it relies on outside parties to challenge the TNSP’s analysis, or to propose alternatives the TNSP will later analyse.

Most outside parties are unlikely to possess the detailed information that the TNSP has, or to have the broad understanding of the network (many parties will only have knowledge of one facet of the network problem and potential solutions depending on their expertise, such as generators or demand aggregators).

Given this asymmetry, the third party discipline created by publishing the results is muted, and limited in its effectiveness.

#### Consequences from the RIT‑T

As discussed above (and in box 17.1), there is no formal regulatory approval of the RIT‑T. The outcome is selected by the TNSP. The only role for the regulator is purely administrative — ensuring that TNSPs have followed required processes — rather than any substantive assessment of the merits of the proposed outcome.

At most, the AER can instruct that the RIT‑T is redone, with the procedural elements (for example, minimum time allowed for consultation) corrected. The AER noted that it felt these powers were ‘limited’ and difficult to exercise:

As the RIT‑T and the associated Electricity Rules are not civil penalty provisions, the only formal remedy available to the AER to address a breach of the RIT‑T is court action seeking an order for the business to redo the RIT‑T. This is both resource and time intensive. (sub. DR92, p. 9)

Indeed, some participants (such as the Total Environment Centre, sub. DR50) perceive the AER’s current role as little more than ‘rubber‑stamping the results of processes conducted essentially by the proponents for their own benefit’ (p. 6).

Further, as noted above, the RIT‑T does not determine the allowed revenue for a particular project (with revenue instead being set through the broader incentive regulation process).

As such, the RIT‑T itself has little (direct) consequence.

### Allowing projects to be justified by reliability standards

The RIT‑T aims to calculate the net present value (NPV) of identified options. However, currently, if the ‘identified need’ (or ‘driver’) for a project is to meet a reliability standard, the project with the highest NPV will be approved, even if that value is negative. In contrast to this, interconnectors are not subject to reliability standards, and must be justified on market benefit grounds (that is, they must have a positive NPV). As there is a lower (and more simply expressed) hurdle for reliability standards, intra‑regional transmission projects could be given priority over interconnectors, despite the lesser relative merits of these if considered through the lens of the NEM as a whole.

One option for reform would be to assign reliability standards to interconnectors so that all interconnectors and intra‑regional transmission received equal treatment under the RIT‑T. The Australian Energy Market Commission (AEMC) considered this as a stand‑alone option in its first interim report of Transmission Frameworks Review (AEMC 2011f). But the optional firm access (OFA) package, considered in the AEMC’s second interim report, included scope for parties to buy ‘firm’ rights for access to transmission capacity on interconnectors (chapter 19), replacing the need for setting reliability standards for interconnectors as a stand‑alone option.[[7]](#footnote-7) Further, to the extent that existing reliability standards are inefficient, ‘levelling the playing field’ by applying similar standards to interconnectors would simply spread any inefficiencies.

In chapter 16, the Commission recommended moving to probabilistically‑set reliability standards for all transmission projects. In the context of the RIT‑T process, a move to probabilistically‑set standards would remove reliability as a separately identified need and, in doing so, remove any potential bias between types of projects. Benefits from improved reliability would instead be considered as a component of the overall benefits, in turn, requiring measurement of the value of customer reliability (chapter 14).

However, including reliability benefits is not straightforward if current approaches to reliability are retained:

* If transmission planning is driven by the specification of deterministic reliability standards (as is currently the case in New South Wales, Queensland and Tasmania), many transmission projects driven by reliability concerns (particularly intra‑regional projects) would run the risk of failing a cost–benefit test. This would result in TNSPs having to conduct modelling and report on projects that show a net cost, but proceeding with (the best of) those projects to meet reliability specifications — in many respects, this is the current practice.
* In the case of the ‘hybrid’ planning currently used in South Australia, and the similar model proposed for NEM‑wide application by the AEMC (appendix F), derived value of customer reliability estimates are used in setting the hybrid standards. As such, projects should, in theory, pass a cost–benefit test (chapter 16). However, changes occurring since the hybrid standard was set, and the coarse nature of the six reliability standard categories, may result in the deterministically‑expressed standard not being closely aligned with economic benefits.

Accordingly, removing reliability as a separately identified need in the RIT‑T requires, at least, a move to hybrid planning (where standards are underpinned by probabilistic cost–benefit analysis). However, using an up‑to‑date probabilistic analysis for each RIT‑T would provide an outcome more aligned with economic benefits. This is considered further in section 17.3.

## 17.3 The future role of the RIT-T

As discussed above, currently the RIT‑T plays a limited role in the process of encouraging, determining and funding efficient transmission investment. It sits parallel to the regulatory determination process (and does not determine funding). The only involvement of the regulator is an assessment of procedural compliance (not approval of investments), and it only applies to certain transmission augmentations (not to replacements).

It is also flawed, with the entity responsible (the TNSP) for performing the test also ‘approving’ the result, and the test itself having little effect to counter‑balance underlying incentives on the TNSP. The information asymmetries facing outside parties also hinders their effectiveness in challenging any of the TNSP’s propositions. The test itself favours projects justified on deterministic reliability grounds (potentially to the detriment of options involving augmentation to interconnectors). Finally, there are few consequences for TNSPs for conducting inadequate RIT‑Ts.

In chapter 16, the Commission recommended a new transmission planning system that incorporates an approval process for large investments based on the current ‘contingent projects’ model. The RIT‑T performs a markedly different role in this new system and, as such, it is important to address the identified flaws inherent in the current RIT‑T.

### Responsibility for performing the test

Under the Commission’s model, the responsibility for performing the RIT‑T will remain with the TNSPs in their role as planners for each jurisdiction.[[8]](#footnote-8) This would allow TNSPs to benefit from economies of scope as they can plan on a basis that considers augmentation, replacement and maintenance as part of a holistic process.

For projects above a certain threshold (see below), the AER would approve revenue allowances for individual projects. This process would operate in a manner based on the current ‘contingent projects’ process. That is, the AER would, in effect, approve the RIT‑T through a revenue allowance.

Further, AEMO would essentially ‘shadow’ the RIT‑Ts for large projects, conducting analyses of its own. Based on these analyses, AEMO would provide advice to the AER relating to technical aspects of individual projects such as their timing, choice and costs. In its position as national planner (with responsibility for the National Transmission Network Development Plan and as planner of last resort), AEMO would be well placed to comment on any NEM‑wide effects or options. This would also allow it to comment on any flow‑on effects from a given investment that may reduce the need for other investments elsewhere in the jurisdiction in question, or the NEM as a whole. Such advice could help to ensure that the AER only approves the net, incremental, investment cost, limiting the opportunities for TNSPs to selectively ‘game’ the RIT‑T by putting projects forward in a particular order, or a particular combination, avoiding the potential for ‘cost shuffling’, as identified by the AER:

But the more there is the opportunity for pass‑through of costs or recognition of change of circumstances such that, “Things have changed, we actually need more money” the more the prospect then that the business can simply label part of the ex ante allowance as being needed for this activity and the demand is now growing in that area. That then frees up capital in other areas for underspends in other areas. There's all sorts of costs shuffling that can go on. (trans., p. 129)

Importantly, AEMO’s advice would have presumptive force with the AER (becoming a form of benchmark). That is, it is presumed that the AER would accept AEMO’s advice, unless the TNSP could provide sufficient, convincing, evidence or arguments to refute it. This could arise in a number of circumstances, for example, where the TNSP’s investment choice has been informed by its detailed local knowledge and experience, or the TNSP may be pursuing more innovative solutions due to the financial incentives it faces. In suggesting a similar model to the Commission’s, Grid Australia emphasised the importance of the ability to refute AEMO’s advice in certain circumstances:[[9]](#footnote-9)

… TNSPs have a much better understanding of their networks, and service performance obligations rest with them. Given these facts it is essential that the option to vary from the recommendations of AEMO remain with TNSPs, where there is strong evidence that AEMO has not chosen the most efficient option and where there is a critical need. (sub. DR91, p. 32)

Giving AEMO’s analysis presumptive force encourages appropriate consideration of NEM‑wide effects and works to counter‑balance some of the underlying incentives faced by TNSPs (which may lead to less than a fully efficient NEM‑wide solution). As the Commission has recommended that AEMO be subject to additional reporting requirements in using probabilistic methods to set reliability standards (chapter 16), requiring AEMO to publish their analysis of a major project could also enhance the ability of other outside parties to analyse TNSPs’ investment decisions, reducing the extent of information asymmetries.[[10]](#footnote-10)

### Consequences from the revised RIT‑T

As noted above, for projects above a threshold value, the RIT‑T would become the first stage in a process based on the current ‘contingent projects’ model. In such instances, the RIT‑T documentation would form the basis of the revenue determination for each project — adding consequences to the RIT‑T by tying it to (a component of) the TNSP’s allowed revenue. The TNSP would nominate large projects (or a set of circumstances that could give rise to large projects, in a manner similar to the trigger mechanism for contingent projects) in its revenue proposal. These would then be subject to the RIT‑T process described below. Additionally, any projects previously identified as ‘small’, which as the time to invest approaches appear likely to become ‘large’ for unforseen reasons, would then become subject to the RIT‑T. In such cases the AER’s revenue determination for the project should take account of the funds already allocated to the project at the time of the regulatory reset, and only allow the incremental increase in funds, not the entire project cost (to guard against double counting of projects).

This process also allows the AER to substantively examine the project selected under the RIT‑T. As with a ‘full’ revenue determination, the AER could investigate a range of issues including the need for, and costs of, a given project and the merits of any alternatives. However, as with a ‘full’ revenue determination, the AER’s role would be to approve the sum of money that the efficient option is expected to cost, *not* to mandate that the identified efficient option is actually built. As with general revenue determinations (chapter 5), if the TNSP were able to complete the project, or meet the identified need, at a lower overall cost (including both capital and operating costs), then it would be able to keep a proportion of the gains.

Once projects were approved through this process, TNSPs could recover the allowed sum through network charges. At the next regulatory determination, the actual project cost (less any depreciation) would be rolled into the TNSP’s regulatory asset base, and the RIT‑T would be used as the basis for any ex post review process if expenditures exceeded the approved amount.

In short, the RIT‑T will become more ‘regulatory’ and more of a test. While the TNSP still conducts the test and selects the investment option, in financial terms, the AER approves both the merit and process of the test, supported by additional input from AEMO.

Recommendation 17.1

The Regulatory Investment Test for Transmission process should be revised. The new test should continue to be performed by transmission businesses, but:

* be accompanied by parallel independent analysis from the Australian Energy Market Operator. This analysis should be published, and provided as advice to the Australian Energy Regulator (AER). The advice should have presumptive force in the AER’s deliberations
* be used by the AER as the basis for a revenue determination for the individual project in question, in a manner similar to the current ‘contingent projects’ process. The AER should assess and approve both the merit and process of the analysis.

### Performing the RIT‑T for replacements?

The RIT‑T is currently only applied for new projects. As such, when an existing asset needs to be replaced, it can be done without performing a cost–benefit test. This would be appropriate if, in most cases, past experience (and initial evaluation) had established that the best investment option would be to replace the existing asset.

However, over time, many of the factors that influenced the original investment decision may have changed, and technological developments may offer alternatives. While TNSPs will have incentives to look at the relative efficiency of alternative options before deciding to replicate an existing asset, if they choose the replication option, any such assessment will remain internal to the provider and, therefore, not open to public scrutiny (outside of an overall, forward looking estimate included in the revenue determination process). Indeed, there is the possibility that the exemption from having to conduct a RIT‑T for replacement projects may have the perverse effect of motivating a TNSP to choose a simple replacement, rather than an alternative, to avoid having to go through the RIT‑T process.

In the context of the Commission’s recommended approach to transmission planning (chapter 16), the application of the revised RIT‑T brings not just transparency, but for large projects is also tied to revenue allowances with focused project‑by‑project scrutiny. In this environment, there could be greater incentive for a TNSP to simply categorise a project as a replacement at the time of the regulatory determination (and thus not consider conducting potentially scale‑efficient augmentations at the same time) to avoid more focused scrutiny of the project, and rely on its inclusion in the (broader) general revenue determination. Further, the level of consultation and scrutiny applied to a project should depend on its significance (in terms of dollars spent, as well as impact on the network), rather than any classification as a replacement for existing investment, or entirely new investment.

Therefore, in contrast to the current contingent project process, the Commission’s model is ‘triggered’ not when some uncertain event occurs, but rather simply by a project costing more than a threshold value (below). As with the current RIT‑T threshold, this would also apply when one possible option to address an identified need exceeded the threshold. This means that *all* projects — both augmentation and replacement projects — above the threshold would subject to the revised RIT‑T.

One potential concern from expanding the application of the RIT‑T to include replacement projects is an associated increase in compliance costs. Indeed, the AEMC submitted that in developing the Regulatory Investment Test for Distribution, it considered including replacement projects but found that doing so ‘would impose a disproportionate regulatory burden on DNSPs [distribution businesses] and it would appear similar reasoning also applies to transmission investments’ (sub. DR89, p. 9). However, the ‘lumpy’ nature of transmission investments (as distinct from distribution investments) suggests that relatively few projects will involve large sums of money (and therefore significant impacts on market participants). As such, a proportionate level of regulatory burden can be applied, providing that an appropriate threshold for application of the test is chosen.

Recommendation 17.2

The revised Regulatory Investment Test for Transmission should apply to all large projects, subject to a uniform threshold value, whether augmentation, replacement or a combination of both.

### A threshold for the test

#### The current RIT‑T threshold

The RIT‑T currently only applies to network augmentations (notably not replacements) where the cost of any option considered is over $5 million. Further, where the preferred option does not cost more than $38 million, the planner applying the RIT‑T can be exempted from parts of the consultation process (AER 2012j, p. 6), effectively conducting a ‘streamlined’ version of the RIT‑T. The $5 million threshold for the RIT–T appears to be a low value, particularly as it applies to the highest cost option considered. However, a low threshold helps minimise the risk of a network business dividing a larger project into several smaller projects to avoid having to conduct a RIT‑T.

The low threshold could be seen as imposing a significant compliance burden on relatively low‑value projects. This would be the case if the costs of all the analysis required for a RIT‑T could be attributed to the test process. But, in fact, much of the analysis that is required for a RIT‑T would be done by a prudent business in any case, to ensure that the capital proposal was justified, even if the results were not published. Further, given that RIT‑Ts are usually done well in advance of a project (as they are supposed to examine investments from the early options stage), it is unlikely that the process would delay the construction of a new asset.

Such considerations suggest that the threshold for the current test is not unreasonable. However, under the Rules, the threshold is to be reviewed periodically by the AER. The first review was completed in November 2012. The review (AER 2012u) concluded that the $5 million threshold should be maintained, but that the consultation threshold of $35 million be increased to $38 million, due to a roughly 10 per cent increase in capital input costs for transmission businesses.

#### A threshold for the revised RIT‑T

The revised RIT‑T process described above sets up individual revenue determinations for specific projects. There are a number of benefits in doing this as it:

* removes a financial incentive to TNSPs to delay important investments. Such delays may put at risk the reliability of the transmission network (given difficulties in observing latent levels of reliability). Under the revised RIT‑T process, there are no incentives for delay as TNSPs cannot access revenues for projects until approved through a RIT‑T process
* minimises the possibility of windfall gains (or losses) as allowed revenues are less reliant on extended demand forecasts, which have significant uncertainties attached
* provides greater public scrutiny over augmentation and replacement options, potentially increasing the ability for TNSPs to discover innovative solutions to network constraints and constraining a reliance on ‘business as usual’ options
* leverages off existing institutional mechanisms (RIT‑T and contingent projects) and so limits incremental administration and compliance costs.

However, the system does impose some additional costs:

* the extra process creates additional compliance and administration costs, which might be significant if most augmentation and replacement activities were to be covered
* it can reduce the ability of TNSPs to substitute between different projects (a significant advantage of well‑functioning incentive regulation) for projects that are on the margins of the threshold.

As such, there is a tradeoff between the costs and benefits of subjecting projects to greater scrutiny. This tradeoff can be accounted for by only applying the revised RIT‑T to projects that meet (or exceed) a threshold value. This would ensure that smaller projects do not incur disproportionate administrative and compliance costs, and that some flexibility to substitute between projects is retained, while still preserving the benefits noted above for larger projects that may present greater risks (and costs) of delays and windfall gains. Any criteria for the application of greater scrutiny would need to consider the:

* proportion of total capital spending covered, and the number of projects (in consideration of the administrative and compliance burden)
* degree of uncertainty associated with certain sized projects (Grid Australia (sub. DR91) put forward that for large transmission projects in particular, timing is critically affected by forecast demand, increasing the degree of uncertainty)
* potential to ‘game’ a threshold by repackaging groups of smaller projects. Lower thresholds will lend themselves more to such gaming as small variations in the definition or timing of the project could determine if it is above or below the threshold. Conversely, the inherently ‘lumpy’ nature of larger transmission projects suggests that higher thresholds are less likely to be gamed
* degree to which investment benefits are easily observable in the day‑to‑day running of the network (for example, where the benefits or costs of delay are easily observable, TNSPs are likely to have greater incentives to complete projects expeditiously. Where they are not, such as some long‑term reliability and ‘net benefit’ driven investments, there are greater risks of investments being delayed or avoided)
* costs of the review system for all parties.

The most administratively simple, clear, and objective threshold to apply is one based on a dollar value. Based on information of the composition of projects over the next five year forecast periods provided by Grid Australia (table 17.1), a threshold in the order of $35 million would appear to be an appropriate starting point. This would capture 7 per cent of augmentation and replacement projects by number (limiting the compliance burden) and, more importantly, 54 per cent of the value of projects (ensuring significant projects are subject to appropriate scrutiny).

Table 17.1 Grid Australia consolidated five year forecast project costs a

|  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Project size | Augmentation | | | Replacement | | Augmentation plus replacement | | | |
|  | $ million ($2012 or $2012/13) | Number | | $ million ($2012 or $2012/13) | Number | $ million ($2012 or $2012/13) | Per cent share (by value) | Number | Per cent share  (by number) |
| $0 to <$5 million | 93 | | 89 | 437 | 536 | 530 | 10 | 625 | 67 |
| $5 million to <$35 million | 532 | | 60 | 1 409 | 178 | 1 941 | 36 | 238 | 26 |
| >$35 million | 999 | | 21 | 1 914 | 42 | 2 913 | 54 | 63 | 7 |
|  |  | |  |  |  |  |  |  |  |
| Total | 1 624 | | 170 | 3 761 | 756 | 5 384 | 100 | 926 | 100 |

a Project costs and numbers are consolidated across different five year periods between 2012 and 2019, based on TNSP regulatory periods. The figures are sums of values for SP AusNet, TransGrid, Powerlink, Electranet and Transend. Augmentation figures do not include SP AusNet. The classification of replacement projects (whether large replacements are grouped as a single project or many different ones) varies between TNSPs.

*Source*: Grid Australia (sub. DR101).

In the first instance, using the revised input cost estimates from the AER’s recent review (AER 2012u) would be a reasonable starting point, suggesting a threshold of $38 million. This threshold figure should be indexed annually in order to maintain its real value.

At the margin, there may be theoretical scope to ‘game’ this threshold by reclassifying projects as costing less than $38 million in order to avoid additional scrutiny. However, as noted above, the Commission considers that several controls would limit the scope (and incentive) for such gaming, notably:

* while TNSPs will be required to nominate foreseeable ‘large’ projects at the time of their regulatory determination, smaller (or new, unforseen) projects that appear likely to become ‘large’ as the time to invest approaches would be also be subject to the RIT‑T
* analysis by AEMO in its various roles could be used as advice to the AER
* the AER’s ability to conduct an ex post review (chapter 5) could identify egregious examples of overspending on transmission projects where the actual amount spent exceeded $38 million (effectively subjecting the process to an ex post RIT‑T, creating greater risk for the transmission business)
* avoiding the RIT‑T does not equate to avoiding scrutiny altogether. Instead, a project would become a part of the general revenue determination process.

Applying this threshold, in concert with the existing RIT‑T arrangements, would see projects split into three tiers:

* $0‑5 million: Projects are not subject to any form of RIT‑T or transparency requirements. Such projects are dealt with entirely through the pre‑existing general revenue determination (and detailed in TNSPs’ annual planning report).
* $5‑$38 million: Projects are subject to the ‘streamlined’ RIT‑T (with fewer consultation requirements). This brings a measure of transparency, but minimises compliance costs. The revenue for such projects is determined through the general revenue determination.
* $38 million and above: Projects are subject to the ‘full’ revised RIT‑T, with input from AEMO. The AER approves the revenue for the individual project through the ‘contingent projects’ process, not the general revenue determination.

Recommendation 17.3

The revised Regulatory Investment Test for Transmission, and the associated project-specific revenue determination, should be triggered when a project (or any of the considered options) exceeds a threshold value. In the first instance, this should be based on the current threshold for application of the full test ($38 million), which should then be indexed over time to maintain its real value.

### Measuring reliability benefits

While most (smaller) transmission projects will be based on meeting probabilistically set reliability standards (chapter 16), for major projects (that is, those above the threshold), undertaking a RIT‑T entails conducting a full cost‑benefit analysis. Essentially, this involves ‘reopening’ the probabilistic reliability calculations, and using the latest available data (particularly regarding the value of customer reliability) to measure reliability benefits as a component of the overall cost–benefit analysis.

As noted above, this removes the need for a separate ‘reliability driver’ for the test, as all projects would now be justified on net benefit grounds.

Conducting a full cost–benefit analysis allows for a more detailed, tailored and up‑to‑date analysis of reliability (and other) benefits for major projects, and makes the selection of economically efficient major investments more likely.

Recommendation 17.4

The Regulatory Investment Test for Transmission should be changed so that reliability is only assessed as a component of overall benefits and not as a separate criterion.

When a Regulatory Investment Test for Transmission is triggered for a major project, a full cost–benefit analysis involving a (public) probabilistic reliability assessment should be conducted.

## 17.4 Other potential improvements

Even if the RIT‑T retains its current role, there are a number of issues and potential improvements to its detailed performance that were raised in the Commission’s draft report. In the context of the RIT‑T’s revised, and more central, role as recommended by the Commission, ensuring that the test functions well takes on even greater importance.

### Other means to improve the transparency of the RIT‑T

One of the main functions of the RIT‑T is to provide a degree of transparency to the transmission investment process. It is therefore important that the RIT‑T is itself a transparent process.

The second interim report of the Transmission Frameworks Review (AEMC 2012j) includes a number of suggestions for improving the transparency of the RIT‑T process, including public reporting of the parties that stand to ‘win’ and ‘lose’ from a new project (even though such transfers are netted out during the calculation of the overall net present value). The review found that these changes ‘were almost universally supported’ (p. 6). However, as the AEMC noted (p. 74), increases in transparency should only be pursued up to the point at which the additional benefits are equal to the additional compliance costs entailed.

The Commission agrees with this principle. However, as noted earlier, absent the public consultation requirement (and consideration of ‘competing’ options involving investments in other regions), most aspects of the RIT‑T process would be conducted by a prudent business before making a major investment, regardless of regulatory requirements. Making such analysis transparent, unless it would substantially risk commercial damage due to disclosing confidential material, would involve little additional compliance cost.[[11]](#footnote-11) Indeed, as Hogan (2011, p. 25) noted in the context of cost allocation of transmission projects, the information that must be produced as part of the evaluation of investments can provide a basis for identifying project beneficiaries in a cost–benefit analysis.

Where possible, and as appropriate, such information could, therefore, be used to augment or inform existing modelling work. Moreover, while wealth transfers might not have an effect on short‑term efficiency, in some cases they can have implications for long‑term efficiency (chapter 19). In particular, where a wealth transfer is expected and repeated, it takes on characteristics of a long‑term investment incentive or disincentive.

### Calculating the benefits

#### Should the RIT‑T include effects in other markets?

The RIT‑T only allows benefits and costs to be counted where they apply to those who consume, produce or transport electricity. Some have suggested that allowing the impacts of an investment to be considered more generally may improve the RIT‑T process.[[12]](#footnote-12) For instance, Grid Australia contended:

… major transmission upgrades may bestow wider economic benefits, which would not be ‘counted’ in a RIT‑T assessment. … However, any mechanism for capturing wider benefits should not unduly complicate what is a relatively complex (but feasible) assessment process. (sub. 22, p. 14)

Similarly, in the 2011 National Transmission Network Development Plan, AEMO argued that:

Changes to the national regulatory and transmission frameworks are needed to enable wider economic benefits beyond the electricity market to be considered, to maximise the value of these investments to Australia. (2011d, p. xxi)

However, as detailed in appendix D, the Commission considers that there are both conceptual and pragmatic reasons for not moving in this direction.

On conceptual grounds, including such wider economic effects would allow the transmission business to count benefits that are not accessible for other industries. For instance, when hiring staff, a manager of a commercial business will only consider whether that decision is cost effective for the business, and not whether it will reduce the regional unemployment rate. Were these broader concerns to be considered in the RIT‑T, it might bias investment away from other sectors of the economy towards transmission projects. It would also require modellers to make difficult judgments about the relevance of potential market distortions in secondary markets to a particular investment project. TNSPs are not well‑suited for such a role. Indeed, the Commission considers that the role of the RIT‑T should be to try to produce investment decisions that (overall) mimic the investment outcomes that might eventuate in a competitive market. Accordingly, the focus should be on an assessment of the electricity market, not the entire economy.

On pragmatic grounds, calculating economywide impacts would require existing detailed market modelling of the electricity sector to be incorporated into either an extended partial equilibrium model or a general equilibrium model. This would be costly to achieve and would make the RIT‑T process significantly less transparent (AER, sub. 13, p. 27).

In any event, adding the complexity of economywide modelling is unlikely to dramatically change the outcome of RIT‑T processes as most projects would have indirect costs as well as benefits (including the opportunity cost of investment in other industries).

Recommendation 17.5

The Regulatory Investment Test for Transmission should not be amended to include indirect effects of investment decisions.

#### Competition benefits

The RIT‑T can include consideration of ‘competition benefits’ — that is, the dilution of localised generator market power where a transmission expansion allows the wholesale market to access more competitive generation from elsewhere in the NEM.

The Grid Australia RIT‑T Handbook (2011a) divides the class of competition benefits into three categories:

* A reduction of deadweight loss resulting from generators being motivated to bid closer to their marginal cost. The size of this gain will be positively correlated to the elasticity of demand in the electricity market concerned.[[13]](#footnote-13)
* An improvement in the merit order dispatch. With market power, a generator may withhold some supply, which will result in lower merit (and higher cost) generators being dispatched, such as peaking plants, and a higher regional pool price. The introduction of further competition makes additional sources of power available to meet demand, reducing reliance on peaking generators and putting downward pressure on prices.
* A generator exercising market power can raise the price of electricity in an area and provide signals for new entrants. A transmission line may defer the entry of the new plant, which could be a significant cost saving that can be considered in the RIT‑T.

The Commission agrees with the framework provided in the Handbook, although it is unclear whether all of the information required for these types of calculations would ever be available in practice. The Commission also understands that, to date, the estimation of competition benefits has focused on benefits of lower fuel costs to energy users. This would suggest that competition benefits may be underestimated.

If, over time, any tendency to underestimate competition benefits is considered to be significant, an adjustment to the RIT‑T methodology could be warranted.

#### Future scenarios

The Garnaut review (2008) raised concerns about the ability of the existing interconnector regulation to facilitate structural change (as carbon policies lead to changes in generator location and technology mix). In particular, Garnaut argued that transmission planners ‘must consider the effects of climate change on demand (higher temperatures) and supply (severe weather events, water scarcity and bushfires)’ (2008, p. 450).[[14]](#footnote-14)

The Commission agrees that modelling methodologies should aim to represent the variables that have major effects on the decision in question. However, neither can these always be accurately predicted nor definitively incorporated into a model. Indeed, most modelling of potential futures will be, by its very nature, an estimate involving simplified relationships between variables.

Currently, AEMO develops a range of future scenarios in the National Transmission Network Development Plan (AEMO 2011d). These scenarios incorporate a range of generation, demand and policy settings. The transparent process of scenario development also allows interested parties (such as network businesses, generators, users and academics) to test the validity of the scenarios on a regular basis. The scenarios are then used by TNSPs for their modelling in RIT‑Ts, with each scenario given a probability weighting. The project that performs the best across the weighted scenarios is then selected.

Without requiring a focus on any particular future outcome (which would risk biasing investment decisions to cater for futures that might not eventuate), these scenarios will update to reflect changing policy settings and available information. Illustratively, AEMO’s latest range of scenarios includes legislated carbon policies (as at January 2012), and also reflects the effect of such policies on economic growth by adopting the Treasury’s ‘core’ modelling forecast for the impact of the carbon price (AEMO 2012g).

The existing range of scenarios appears suitably broad, and is developed and updated independently of those who could have a financial incentive to game it. As such, the Commission considers that existing range of scenarios is suitable for the task of planning for an uncertain future.

#### A bias away from gas transport alternatives?

Issues with the RIT‑T process can occur when there is a choice between meeting a need with an electricity transmission project or through a gas pipeline. For example, electric power can either be generated at a gas field and transmitted to the city, or gas can be piped to the city and power generated there.

Under current NEM rules, provided that there is a transmission line nearby to the gas field, generators have an incentive to locate close to the gas fields, as they do not have to pay the full cost for the construction of the transmission line (only shallow access fees). Yet where both options are being considered with no pre‑existing investment to bias the choice, the capital cost of building infrastructure to transport gas is significantly lower than that for electricity. Some estimates suggest electric energy is between 1.5 to 2.5 times more expensive to transport as the equivalent amount of gas energy (AEMO 2011d).

Further, a generator’s choice of location can contribute to congestion in the transmission network, necessitating (or bringing forward) other transmission investments (currently a cost that is recovered from users, not generators). As such, locating close to a gas field may appear cheaper to generators, but it may have a higher long‑term cost to the economy as a whole (particularly to electricity users who ultimately pay directly through transmission charges, and indirectly through transmission losses or costs that arise from congestion (chapter 19).

As it does not explicitly consider gas transport alternatives as options, the RIT‑T could be seen as too narrow, and thus may not result in the most efficient method of transporting energy. However, TNSPs (and electricity planners more generally) do not have the authority to direct gas pipeline investment. Consequently, a RIT‑T that considered gas and determined it was the best option, could lead to a perceived ‘gap’ in the market if pipeline owners chose not to invest (deploying their capital elsewhere). However, if the RIT‑T analysis is transparent, and interested parties have a good understanding of the options (and benefits) considered, then normal commercial incentives may act to encourage an efficient outcome.

Given the problem arises due to generators not facing the ‘true’ cost of their connection to the electricity network, the best solution lies not with the RIT‑T, but in exposing generators to a larger share of the network costs they create. Some potential options (such as ‘firm access’ payments, which could create a level playing field for gas and electricity) are discussed in chapter 19.

1. ` Currently, a ‘major project’ is one in which any of the options considered would cost more than $5 million. For projects between $5 and $38 million, a ‘streamlined’ version of the RIT‑T is conducted with lower consultation requirements. Projects above $38 million require a standard RIT‑T. The previous threshold of $35 million was recently reviewed by the AER in 2012, and updated to $38 million to reflect changes in input costs (AER 2012u). [↑](#footnote-ref-1)
2. The AER (2010e) only stipulate that a ‘commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector’ be used to calculate the net present value. Grid Australia’s (2011a) RIT‑T cost–benefit analysis handbook suggests a 10 per cent rate should be used, unless there are ‘compelling reasons to adopt a different rate’. [↑](#footnote-ref-2)
3. The TNSP is required to make the project specification report available to all registered participants (in the NEM), AEMO, and ‘interested parties’ (AER 2010g). ‘Interested parties’ is broadly defined to include those with an interest in network planning, or with the potential to suffer an adverse market impact from the proposed transmission investment. Both AEMO and the AER play a role in determining whether a party qualifies as an ‘interested party’. [↑](#footnote-ref-3)
4. Hypothetically a (short‑term) customer benefits test could approve an investment that resulted in a benefit, of say $1 million to electricity consumers, but imposed a cost on particular generators (which would be unlikely to be able to fully recover the cost through the wholesale market) of $2 million. This could provide a disincentive for those generators to invest, and cause power supplies to fall below efficient levels in the future. (Note that the NEO, in focusing on the *long‑term* interests of consumers, would be unlikely to be met for such an investment.) [↑](#footnote-ref-4)
5. In effect, the RIT‑T is a test where the TNSP sets the questions, prepares the answers and marks the exams themselves. The AER and other parties act only as observers, able to comment but not ‘mark’ the exam themselves. [↑](#footnote-ref-5)
6. At broad level, AEMO already effectively sets the scenarios as the TNSPs adopt those set out in AEMO’s National Transmission Network Development Plan. [↑](#footnote-ref-6)
7. Under the OFA package, TNSPs would be obliged to maintain interconnector capacity to meet the subscribed levels of access. This level of capacity would be subject to a ‘firm access standard’ (chapter 19), which would effectively perform the same role as a reliability standard. [↑](#footnote-ref-7)
8. The Commission considers that Victoria should also transition to the NEM-wide system (chapter 16). Accordingly, SP AusNet would eventually take over responsibility for the RIT‑T/contingent projects process. [↑](#footnote-ref-8)
9. In Grid Australia’s ‘enhanced AEMC model’ (sub. DR91) the RIT-T would also be conducted by the transmission business ‘with scrutiny by AEMO and oversight of the AER’ (p. 12). [↑](#footnote-ref-9)
10. Theoretically, a third party could use published information to run the probabilistic model used by AEMO to set reliability standards. This would highlight some of the assumptions made by TNSPs in concluding that a particular investment was needed, and that it had a net benefit. [↑](#footnote-ref-10)
11. Examples of possible confidential material might include the details of contracts with construction firms. These firms could suffer financial loss if their competitors discovered, and copied, particular aspects of their bidding and contracting arrangements. [↑](#footnote-ref-11)
12. This issue was also considered by ACIL Tasman (2006). [↑](#footnote-ref-12)
13. There will be a rent transfer, from generators to consumers but, as discussed above, these are not considered under the RIT‑T framework. [↑](#footnote-ref-13)
14. In his review, Garnaut (2008) contemplated a NEM‑wide assessment, similar to the Californian Energy Transmission Initiative, as a role for the national transmission planner. [↑](#footnote-ref-14)