The Allen Consulting Group

Review of Energy Market Frameworks in light of Climate Change Policies

Climate change policies and the application of the Regulatory Investment Test for Transmission

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Note to the Australian Energy Market Commission

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Section 1

Purpose and scope

The purpose of section 2 of this note is to explain how the effects of the proposed expanded renewables energy target (ERET) and the proposed carbon pollution reduction scheme (CPRS) should be treated when undertaking a cost benefit test of new transmission investment.

The purpose of section 3 is to explain why the existing guidelines to the regulatory test require the test to be satisfied when the net present value of the project is maximised, rather than just that the net present value is positive. This matter recently has been raised in consultation.

Section 2

ERET, CPRS and the Regulatory Test

2.1 Background – intended effect of the ERET and the CPRS

Expanded renewables energy target

The policy objective of the Expanded Renewable Energy Target (ERET) scheme is to provide for the subsidisation of renewables generation until the point where the renewables target is met, and then for the subsidy to cease.[1] The scheme as a whole, therefore, can be interpreted as a mandatory obligation on the market for the renewables target to be met, with the Renewable Energy Certificates (RECs) being the financial device for delivering the subsidy to the renewables generators and encouraging the target to be met at least cost.

More specifically, renewable generation projects would be expected to enter and sell the RECs produced to retailers for the latter to meet their renewable obligations. Entry would be expected first in the areas whose unit cost is lowest — and hence that require the lowest subsidy to be profitable — which would depend on such factors as:

- the quality of the renewable resource:
  - for example, the quality of a wind resource would depend on the expected average wind speed of the area and profile of that wind, as this in turn would determine its expected revenues for a given project size (maximum output) and forecast of electricity spot prices (or, alternatively, determine its cost per MWh generated);
- the capacity of the network to accept its energy output;
- forecasts of spot prices in its region;
- the transmission loss factor in the relevant area (also the distribution loss factor if the wind farm is connected to the distribution network); and
- the costs (such as land) or other constraints (such as environmental) of constructing a wind farm in different areas.

Once options for further development in the lowest cost sites are exhausted, it would be expected that entry of renewable generation in higher cost areas would proceed. As a consequence, the price that a retailer would need to pay for the RECs created would need to rise to the extent necessary to make the higher cost projects profitable. In a well functioning market, the equilibrium price for renewable energy certificates would be expected to settle at a level that encourages entry by the target level of renewable generation, which in turn would be expected to settle at a level that reflects the minimum of:

[1] It is assumed in this note that the expanded renewable energy target scheme largely will mirror the current scheme albeit with an expanded target, namely that each retailer will have to purchase renewables certificates (RECs) for a proportion of its annual energy sales — which will rise to 20 per cent by 2020 — or pay a financial penalty. Compliance with this requirement would be assessed at the end of the year. In parallel with this, renewables generators get a REC for each MWh of energy produced.

- the difference between the average cost of the highest cost (i.e. marginal) renewable generator and the expected average pool price; and
- the short fall penalty — currently $40 per MWh — which would operate as a de facto price cap on the value of renewable certificates (i.e., a rational retailer would not agree to pay more than the shortfall penalty for RECs).

It is possible that more renewables generation may enter than required to meet the renewables target. In this situation the additional RECs would not be purchased by retailers — as they would have already met their obligation — and so the additional RECs would not have a value (or, alternatively, the oversupply of RECs would cause the price of all traded RECs to decline).

Carbon pollution reduction scheme

The central feature of the Government's proposed carbon pollution reduction scheme (CPRS) is a "cap and trade" system for carbon and equivalent emissions, which is assumed to operate as follows:

- A prescribed number of permits will be made available, part of which may be given away and the remainder sold initially for a fixed price (for 2010 2012) and then auctioned.
- Any carbon emitter is required to have sufficient carbon credits to meet its carbon output, which is assessed at the end of each year, or face a deterrent penalty with an obligation to "make good" (i.e. purchase sufficient permits in the next period to cover the earlier shortfall so total carbon emissions do not increase).
- Carbon permits may be purchased on a secondary market which, initially at least, will be limited to Australia. They may also be created by investing in programs to "offset" carbon emissions in industries (such as forestry) that are outside of the scope of the scheme.

The policy objective of the CPRS is to have all decision in the economy — including electricity generation operating and investment decisions — to take account of the social cost of meeting the government's desired level of future carbon emissions. As the number of carbon permits to be issued will be capped, they will have a value, and would be expected to settle at a level that reflects the lesser of:[2]

- the loss of economic value from a marginal reduction in carbon emissions anywhere in the economy; or
- the cost of a marginal increase in the sequestering of carbon, anywhere in the economy.

It follows that the price of carbon permits will indicate the (marginal) social cost of meeting the Government's desired level of carbon emissions.

[2] This is after any transitional prices for carbon (expected to be for the first two years) have ceased.

Specifically in relation to electricity, the CPRS will require fossil fuel and other carbon emitting generators to purchase sufficient permits to cover their measured carbon emissions. The price for these permits, in turn, would reflect the trajectory for carbon emissions set by the government (i.e. the supply of permits), the "willingness to pay" for carbon permits in all sectors of the economy and the cost of creating carbon permits where permitted (e.g. in forestry), as discussed above.

The requirement for carbon emitting generators to by carbon permits will raise their operating cost according to the carbon intensity of their generation. Generators would be expected to raise their bids in light of this new cost, and as the bids from the majority of the current and forecast stock of generators would have risen, spot prices — and therefore contract prices — would be expected to rise. The order of dispatch would be expected to alter as the cost (and hence bids) of less carbon intensive plant would reduce relative to the cost of more carbon intensive plant. It is also possible that a sufficiently high price for carbon permits would encourage existing generators to close prematurely, or reduce incentives to extend the life of existing facilities.

The CPRS will also affect the choice of generation technology for new entry. The cost of less carbon intensive generation would fall relative to carbon intensive generation, and hence encourage a switch towards less carbon intensive technologies. Generation technologies that do not produce carbon emissions — like wind power — would receive higher pool prices while bearing no additional costs, which would improve their commercial viability unambiguously (putting aside the interactions with the ERET scheme, discussed below).

Interactions between the ERET scheme and CPRS

It should be noted that it would be expected that either the ERET scheme or the CPRS would be redundant for renewables generators, depending on the settings of the schemes. In particular:

- *Very high carbon price* — if the carbon price is sufficiently high so that renewables generation is financially viable from sales at the spot or contract prices, then RECs should have no value, and hence the ERET scheme is redundant.
- *Lower carbon price* — at carbon prices that are lower than needed to make renewables financially viable, an increase in the carbon price — and resulting increase in the spot price — would just mean that renewables need a smaller subsidy to be financially viable, which in turn should translate into a corresponding reduction in the value of RECs. Thus, the CPRS would not deliver a marginal benefit to a renewables generator (or at least to the marginal renewables generator).

2.2 Assessment of new transmission investment

Background — costs and benefits from transmission investment

The issue of relevance of this paper is where a constraint on the transmission network limits the output of generation from a particular location and where undertaking a transmission investment to alleviate that constraint would permit:

- additional output from existing renewable generators or low carbon generators; and/or
- entry of new entrant renewable generators or low carbon generators.

Turning to the cost of transmission investment, this is merely the upfront and ongoing cost associated with the transmission network upgrade, expressed in present value terms.

Turning to the benefits expected from transmission investment, one of the key drivers for many of the Australian TNSPs to augment the transmission networks is to meet a prescribed (deterministic) planning standard with respect to the resilience of the network in the face of contingencies. However, a range of wider economic benefits may also be delivered by additional transmission transfer capability, which includes the following:

- *Reduced generation operating costs* — the transmission upgrade may permit the dispatch of generation that has a lower operating cost than if the constraint persisted. The economic benefit is the difference in the operating cost that would be incurred with the generators forecast to be dispatched “with” and “without” the transmission upgrade occurring.
- *Reduced generation capital costs* — increasing the capability for the transmission network to receive energy from a particular location may permit lower cost generation to be constructed “with” the upgrade than would be possible “without” the transmission upgrade.
- *System reliability* — transmission investment may permit a reduction in expected unserved energy as they connect additional sources of supply and thus more resilience in the presence of generation or network outages.[3] A formal estimation of system reliability benefits would generally involve conducting a Monte Carlo estimation (i.e. using known failure rates for the different generation and transmission equipment) of expected unserved energy without the transmission upgrade and with the transmission upgrade, and then assigning a value to that change in unserved energy.
- *Reduced transmission costs* — constructing one transmission project may imply that other transmission projects that otherwise would have been undertaken would be avoided.
- *Reduced transmission losses* — constructing additional transmission plant may reduce the amount of energy that is lost during transportation to the customer.

Where transmission businesses are subject to mandatory obligations, then the optimal transmission investment need not deliver quantified benefits that exceed the costs.[4] However, the classes of benefit discussed above remain relevant to the selection of the optimal project, in particular:[5]

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[3] It should be noted, however, that transmission investment may permit new generation entry to be deferred – as better use is made of the surplus capacity on the generation rich side of the constraint – which may lead to a reduction in system reliability (i.e. so that there is a trade off between saving generation costs and system reliability).

[4] Where TNSPs are subject to mandatory obligations, the benefit from meeting the mandatory obligation need not be quantified.

[5] The AEMC has recently recommended a new version of the regulatory test for transmission that facilitates the consideration of the additional benefits and costs that a reliability-driven project may deliver.

- *Generation operating and capital costs* — projects that meet the mandatory obligation may also permit reductions in generation costs, the value of which should be considered when selecting the optimal project; and
- *System reliability* — projects that meet the mandatory obligation may also deliver levels of reliability above the minimum requirement, the value of which should be considered when selecting the optimal project.

The estimation of these benefits in light of the ERET scheme and CPRS are discussed in turn below.

2.3 Application of a cost benefit test for transmission in the presence of the ERET scheme and CPRS

ERET scheme

As discussed above, the ERET scheme is in the nature of a mandatory obligation on the electricity supply industry to achieve the target share of renewables generation, with the role of the RECs being to provide a mechanism to encourage the obligation to be met at least cost. The outcomes from the scheme should be that either:[6]

- the target for renewable energy is met, and the value of RECs rises to the level necessary to make the marginal renewable generator commercially viable; or
- the value of RECs rises to the implicit cap on the value of RECs prior to the renewables target being met, and so the target is not met, but retailers instead opt to pay the financial penalty.

The effect of the renewables scheme, therefore, is that there will be substantial new entry of renewables electricity generation. As a result, the main (but not exclusive) economic benefit that could flow from a transmission augmentation to permit greater output from renewable generators is to permit the total cost of meeting the renewables obligation to be reduced. This reduced cost would arise by:

- making better use of existing renewables plant rather than constructing new plant; or
- permitting the entry of renewables plant that has a lower unit cost than would be the case if renewables generation instead was built in the next best location.[7]

In terms of the classes of benefits discussed in section 2.2, this benefit would be a reduction in generation capital cost. Depending on the type and location of renewable plant that may be attracted, other benefits also may be created.

Thus, a comprehensive assessment of the benefits would involve using appropriate market models to:[8]

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[6] The analysis in this section assumes that the CPRS does not cause electricity spot prices to rise sufficiently high to make the target quantity of renewables generation commercially viable without receiving a subsidy through the ERET scheme.

[7] As discussed above, the unit cost of wind generation in particular would be expected to vary materially across the NEM reflecting the different quality of wind for generation across the NEM.

[8] This is essentially the same conclusion that NERA reached in a recent report to the AEMC: NERA, 2008, Implications of climate change policies for electricity network service providers, August. It is noted, however, that the implicit assumption in the discussion above is that the renewables target is forecast to be met (i.e., retailers do not opt to pay the financial penalty rather than purchasing RECs). If the financial penalty is forecast to be lower than the cost of RECs then a slightly more complex formulation that factors in the financial penalty is required.

- project the expected future generation investment without the transmission upgrade being in place – factoring in the effect of the ERET scheme on new generation investment;
- project the expected future generation investment with the transmission upgrade being in place – also factoring in the effect of the ERET scheme on new generation investment;
  - the difference between the two projections above would be the forecast saving in generation capital costs;
- project the expected future generation dispatch without the transmission upgrade in place;
- project the expected future generation dispatch with the transmission upgrade in place;
  - the difference between the two projections above would be the forecast saving in generation operating (dispatch) costs;[9]
- project the expected future losses without the transmission upgrade in place;
- project the expected future losses with the transmission upgrade in place;
  - the difference between the two projections above will be the forecast saving in transmission losses;[10]
- (possibly) project the expected unserved energy without the transmission upgrade in place; and
- (again, possibly) project the expected unserved energy with the transmission upgrade in place:
  - if undertaken, the difference between the two between the two projections above will be the change in expected unserved energy caused by the transmission upgrade.

The method described above involves estimating directly how transmission augmentation may reduce the cost of meeting the ERET scheme. In this analysis, the value of RECs should be ignored – to also take account of the effect of the transmission project on the price of RECs would amount to double-counting.

The question arises, however, as to whether a simpler approach for estimating the 'ERET benefit' of a transmission upgrade would be to estimate how that project may reduce the cost of RECs. The short answer to this question is "no". In particular, even though factoring the cost of RECs into the analysis of transmission projects may appear to be the correct approach, it is unlikely to provide an accurate estimate of a project's ERET benefit and is also unlikely to be simpler than the approach described above.

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9 If the effect of the transmission upgrade is to encourage wind generation in location A rather than in location B, then the transmission upgrade may not have a material effect on generation operating costs.

10 Losses may rise or fall with the transmission upgrade depending on the effect of the upgrade on generation locational decisions.

First, minimising the cost of RECs (and therefore the total subsidy required for renewables projects) will not translate into meeting the renewable obligation at least cost. The reason for this is because the cost of RECs would be unaffected by the cost of transmission upgrades that pass the regulatory test and are recovered through prescribed service charges, which is turn reflects the fact that the cost of the shared transmission network is recovered wholly from customers. Thus, seeking to minimise the cost of RECs would not equate to minimising the total cost (i.e., including the cost of transmission) of meeting the renewables obligation. This is demonstrated further with a simple example in Appendix A.

Secondly, even if minimising the cost of RECs did equate to minimising the cost of meeting the renewables obligation, a similar estimation method to that described above would be required in any event to ascertain how a transmission upgrade would be expected to affect the cost of RECs. In particular, the affect of a transmission upgrade on the cost of RECs would depend upon the cost of the renewable generation that would have been built *without* the transmission upgrade compared to the cost of the renewable generation that would be built with the transmission upgrade in place. Thus, incorporating the cost of RECs into the analysis of transmission upgrades would not imply a simpler analysis to estimating directly the effect of the transmission upgrade on the cost of meeting the renewables obligation.

CPRS

Incorporating the effect of the CPRS into a cost benefit test of a transmission upgrade is a more straightforward task than that of the renewables obligation. As discussed above, the policy objective of the CPRS is to set a limit on the overall (economy wide) emission of carbon, and to expose all carbon emitters to the social cost of meeting that obligation. The social cost is exposed to emitters through the price that must be paid to purchase carbon permits — with this price expected to reflect the reduction in the value of economic activity or consumption from the marginal reduction in carbon emissions across the economy or the cost of creating new credits through approved carbon sequestration. The intention, therefore, is for all carbon emitters to behave — and make decisions — as if the price for purchasing carbon credits is equivalent to the price of any other input.

It follows that the most straightforward means of accommodating the effect of the CPRS into cost benefit assessments of transmission projects is to treat the price of permits as a generation operating cost. It follows that, if a transmission upgrade would permit additional dispatch of an existing low emission generator, or would encourage additional investment in low emission generation, then the reduction in the cost of purchasing carbon permits would appropriately be included in the estimated savings in generation operating costs.

2.4 Does the current regulatory test and proposed RIT–T accommodate the ERET scheme and CPRS?

The regulatory test and guidelines for its application provide for a comprehensive assessment of the benefits of transmission projects. The binding constraints are that the benefits are restricted to those received by electricity market participants in that capacity (i.e. not related to externalities) and that the benefits are true economic benefits (i.e. that transfers are excluded). It would be unexpected, therefore, that the tests were not sufficient to take account of these new policy measures.

The most important aspect of the method described above for incorporating the effects of the ERET scheme into the assessment of transmission benefits is to take account of the ERET scheme when forecasting the future type, timing and location of generation capacity "without" and "with" the transmission augmentation. The AER's regulatory test guidelines do not provide definitive guidance on what should be assumed to exist in the world "without" and "with" the transmission upgrade; however, it can be inferred that the future world should be modelled as realistically as possible:[11]

> The *market benefit* of an option (or alternative option) can only be calculated by a comparison between the state of the world with the option in place to a state of the world in which the option is not in place.

Regarding the CPRS, the method described above involved treating the purchase of carbon permits as a generating operating cost, so that a reduction in the permits required would imply a commensurate benefit. The regulatory test refers explicitly to the change in generation operating cost as being a possible source of benefit from a transmission project,[12] and the cost of carbon permits clearly would fall within the scope of generation operating costs.

Notwithstanding, the appropriate treatment of the schemes in the regulatory test — the ERET in particular — is not necessarily obvious, and so there would be a benefit from clarifying the treatment of these schemes, for example, through explicit treatment in the AER's guidelines.

2.5 Summary of conclusions

The value of RECs should be excluded from cost benefit assessments of transmission upgrades. Instead, the pattern of generation should be projected "without" and "with" the transmission upgrade, taking account of the effect of the renewables obligation. It would be expected that the most significant economic benefit from a transmission upgrade to an area of low cost renewable generation potential would be to permit the renewables obligation to be met at lower (generation capital) cost.[13]

The cost of acquiring carbon permits under the CPRS should be treated as a generation operating cost. A transmission project that permitted additional low carbon generation would reduce the cost to the industry of purchasing carbon permits, which is a valid economic benefit to attribute to the transmission upgrade.

The regulatory test and accompanying guidelines would appear to provide sufficient flexibility to take account of the ERET scheme and CPRS when estimating the benefits of a transmission upgrade. Notwithstanding, explicit guidance would be desirable, for example, by providing explicit guidance in the AER guideline.

[11] AER, 2007, Regulatory Test Application Guidelines, November, clause 4.1(b).

[12] AER, 2007, Regulatory Test Version 3, November, clause 4(d)(ii).

[13] Note that an adjustment to this calculation would be needed if the modelling suggested that retailers would opt to pay the financial penalties rather than contract with additional renewables generators and hence the renewables target would not be met.

Section 3

Requirement for the net present value of the project to be maximised

3.1 Introduction

The regulatory test requires the net present value of the project to be maximised,[14] which includes that the net present value be maximised across different potential commencement dates for the relevant project.[15] The comment recently has been made that it is inappropriate for a project to be deferred until the present value of its net benefits is maximised, but rather that the project should be commenced whenever the present value of its net benefits is positive.

It is concluded below that it is appropriate to undertake projects when the present value of the net market benefits is maximised rather than merely positive. In particular, it is shown that if deferring the project would raise the present value of that project's projected net market benefit, then the benefits received during the years that the project is deferred will exceed the costs – and so deferring the project will create a net economic gain.

This proposition is illustrated below with two examples. The first example reflects the simplest of all cases, namely where the annual benefit from the transmission upgrade increase over time. The second example addresses a more complex case, namely where the benefit that a transmission upgrade would provide vary from year to year.

3.2 Example 1 – increasing annual benefits

Figure 3.1 illustrates this proposition with a very simple example, in which it is assumed that:

- the upfront cost of a transmission project is $100 million, the project has an infinite life and operating and maintenance costs are ignored;[16]
- the annual economic benefit from the transmission project commences at $5 million if the project was in place at the start of year 1, and rises thereafter linearly by $1.1 million per annum; and
- the discount rate — and cost of capital — is 9 per cent.

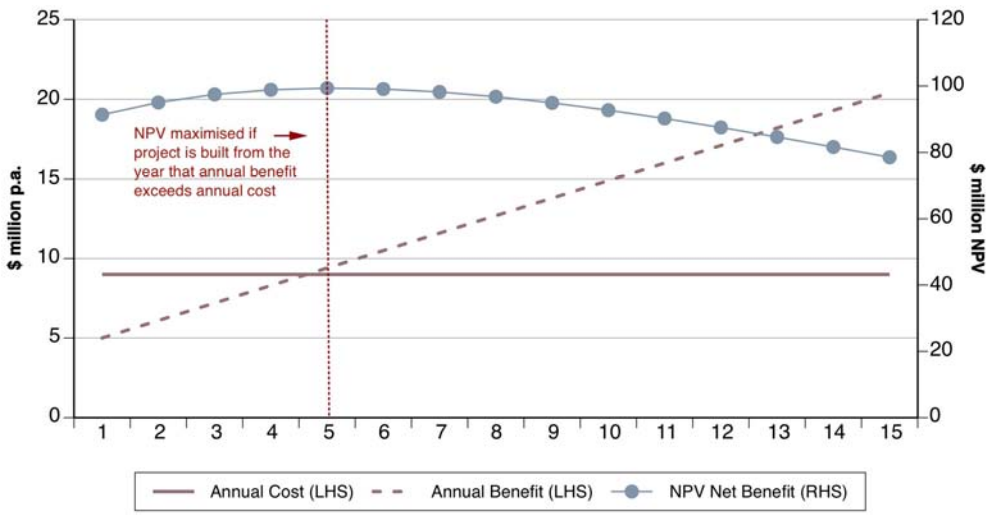
[14] AER, 2007, Regulatory Test Version 3, November, clause 1(b).

[15] The requirement for the timing to be optimised is not explicit in the Regulatory Test (although a different timing of the proposed project may fit within the definition of an alternative project, which the TNSP has to consider. The requirement to look at alternative commissioning dates, however, is implicit in the AER's guidelines for the application of the test (see AER, 2007, Regulatory Test Application Guidelines, November, clause 4.1(c)).

[16] This assumption is not necessary and does not change the results, but rather has been imposed to make the modelling simpler.

Figure 3.1

ANNUAL BENEFIT, COST AND NPV OF NET BENEFITS



The *dashed* in Figure 3.1 shows the forecast annual benefit from the transmission project as described above. While benefits need not rise uniformly over time, it is plausible — indeed, likely — that the benefit from a transmission project would increase over time.

- As discussed above, the benefit from a transmission project is the difference between the economic costs that would be incurred by participants without the transmission project and the economic costs that would be incurred by participants with the project in place. As congestion would be expected to rise over time in the "without" case — as demand grows — the annual benefit from a transmission upgrade would also be expected to rise.

- As an example, a constraint may limit a low fuel cost generator to supply 200 MW at peak times, with the remainder having to be supplied by a higher fuel cost generator. As demand grew, a greater amount of energy would need to be supplied by the higher fuel cost generator. Thus, assuming the low fuel cost generator had sufficient capacity, the fuel cost savings from removing the constraint (and thus permitting the low fuel cost generator to displace the high fuel cost generator) would rise over time in an approximately linear fashion.

The *solid (no symbols) line* in Figure 3.1 shows the cost of the transmission project, converted into an annual cost. Thus, in the years after the transmission project is constructed, an annual financing cost of $9 million would be incurred (i.e. a cost of capital of 9 per cent).[17]

The *solid (circular symbols) line* in Figure 3.1 shows the present value of the project if the project is in place for the year in question, discounted back to the start of the period in order to make the values comparable. Thus, the present value of the project's net benefit commences at about $84 million if the project is in place for year 1, but rises if the project is deferred, reaching a maximum of $91 million if the project is in place for year 5.

17 As the project is assumed to have an infinite life the annualised cost is merely the cost of capital multiplied by the initial cost.

If all of the lines are compared, it is evident that in the years where the present value of net benefit is rising, the annual benefit from the project is lower than the annual cost — this is the case for years 1 to 4 where annual cost is above the annual benefit. Thus, if the project is deferred during this period, the reduction in annual financing costs will exceed the reduction in annual benefits — and society wopuld be made better off by deferring the project. The present value of net benefit is maximised in the year when annual benefits first exceed annual costs (i.e. year 5, as indicated in the figure) – which is therefore the time at which further deferral of the project would lead to a larger reduction of benefits than cost, and hence is the time at which the project should be in place.

3.3 Example 2 – lumpy annual transmission benefits

The example provided above is a very simple one and it may be the case that annual benefits may vary over time. Given that the annual cost of a project will be constant (under the assumptions adopted above), these 'lumpy' annual benefits may cause the annual net benefit to be positive in some years and negative in others. However, as a general proposition, if the present value of the project's net benefit is projected to rise if the project is deferred, then it must follow that the present value of the net benefit in the intervening period is negative, which would mean that there is an economic benefit from deferring the project.

A simple numerical example will also demonstrate this proposition. In the results for this example set out in Table 3.1 the same assumptions are made about the cost of the relevant project as assumed in Figure 3.1 above. However, rather than being a smooth function, the annual benefit is assumed to vary. Specifically the project is assumed to deliver a market benefit of 12 if it is in place for year 1 and then a lower level of benefits — but increasing — in the years thereafter. This could reflect the fact that the construction of the project may permit a large reduction in generation fuel costs for the first year, but which then are expected reduce because of the entry of a new, low cost generator.

Table 3.1

NET MARKET BENEFITS WITH "LUMPY" BENEFITS

Year	1	2	3	4	5	6	7	…
Annual benefit	12.00	3.00	5.00	7.00	8.00	9.10	10.20	…
Annual cost	9.00	9.00	9.00	9.00	9.00	9.00	9.00	…
Annual net benefit	3.00	-6.00	-4.00	-2.00	-1.00	0.10	1.20	…
NPV Net benefit	**81.53**	**78.78**	**83.83**	**86.92**	**88.33**	**88.98**	**88.92**	**…**

As with the example above, the annual cost is the annual cost that is incurred in all years after the project is in service, and "NPV net market benefit" for any year is the present value of the annual net benefit if the project is in place for that year (thus, if the project is commenced in year 7 then the net present value of its annual net benefits from that time forward would be $88.92, discounted to the start of the period).

The in example provided in Table 3.1, if the project is in service for year 1, then it would deliver a large benefit in that year that is substantially would be excess of the annual (financing) cost of the project in that year. However, for the next four years, the annual benefits are low and fail to offset the annual cost that would be incurred from investing in the transmission asset.[18] Thus, while a net benefit of 3 is made in year 1 (NPV = 2.75 to the start of year 1), aggregate net losses of 13 would be made over the next 4 years (NPV = -10.21). These results mean that:

- having the project in service for year 1 would mean that the benefit in year 1 (NPV = 2.75) would be received; however
- deferring the project to year 6 would avoid the losses projected in the subsequent years; which means that
- there would be a net gain from deferring the project to year 6, which is given by: 2.75 + 10.21 = 7.45. Note that this gain from deferring the project is also the difference between the NPV of the net benefit from constructing the project to be in service for year 1 (81.53) and for year 6 (88.98).

It follows that the optimal time for having the project in service is the time at which the present value of its net market benefits are forecast to be maximised.

[18] Transmission investments are irreversible. Therefore, once an asset has been built, the annual financing costs will be borne from that time forward irrespective of whether the asset generates benefits.

Appendix A

Can the value of RECS be used in the Regulatory Test?

The method proposed in this note for incorporating the effects of the ERET in the regulatory test is to ignore the traded value or cost of RECs. Instead it has been proposed to forecast directly how the relevant transmission upgrade would change the future stock of generation, in all cases taking account of the effect of the ERET scheme on future generation entry. However, the question remains as to whether an alternative would be to infer the value of transmission investment from the change in the value of RECs and possibly obviate the need to forecast future generation entry and costs.

The conclusion reached in this note is that the value of transmission upgrades cannot be inferred simply from the value or the change in value of RECs — and indeed that this is likely to overvalue transmission upgrades. This is best illustrated by way of a simple example, which assumes as follows:

- Unit cost of generation in location 1 (the constrained location) is $80/MWh;
- Unit cost of generation in location 2 (the unconstrained location) is $100/MWh;
- Cost of resolving the constraint to location 1 is $10/MWh; and
- Expected average pool price is $50/MWh at both locations, which is not expected to be affected by either project.

Assuming that one of the generators is required to be constructed to meet the renewables target, the efficient response would be to construct the transmission upgrade. The total cost of constructing further generation in the constrained region would be $90/MWh (including the cost of the transmission upgrade), which is still lower than the cost of constructing generation in the next best unconstrained location (of $100/MWh). Table A.1 shows how the results of the cost benefit test as described above would look and how the value of RECs would be affected by the choice of project.

Table A.1

EXAMPLE OF GENERATION COST SAVINGS AND RECs

	Cost ($/MWh)	Generation benefit	Transmission cost	Net benefit	Value of RECs required[19]	Difference in RECs required
Location 1	80	20	10	10	30	20
Location 2	100	n/a	n/a	n/a	50	n/a

[19] As discussed above, it is assumed that the cost and value of RECs reflects the difference between the expected pool price and the generator's unit cost (i.e. the required subsidy).

The cost benefit test as described previously — which focuses on the physical costs and ignores the value of RECs — delivers an estimated net benefit to the transmission upgrade of $10/MWh. This is equal to the saving in total cost that would arise from installing generation in location 1 and upgrading the transmission network rather than installing generation in location 2. The cost benefit test correctly identifies the efficient option and the savings it would create.

In contrast, the cost/value of RECs would be $20/MWh lower if the project was constructed in location 1, which overstates the cost savings that would result from constructing generation in location 1 compared to location 2. Indeed, if the cost of transmission was $25/MWh, then construction in location 2 should then be preferred (total cost of location 1 of $100/MWh compared to $105/MWh in location 2); however, the cost/value of RECs would still be $20/MWh lower if the generator was constructed in location 1. Thus, if the reduction in the cost/value of RECs was used as a proxy for the benefit of a transmission upgrade, then the transmission upgrade would be preferred when it not the efficient option.

The reason why the cost/value of RECs — or, more specifically, the forecast reduction in the cost/value of RECs — does not provide an indicator of the relative efficiency of transmission investment is because generators do not pay for using the shared transmission network. This means that the transmission costs that are caused by a particular project would not be reflected in the cost/value of RECs.[20] Accordingly, there is no mechanism for the cost of the transmission upgrade to affect the value of RECs.

Moreover, even if generators did pay for using the transmission network — and transmission prices “signalled” the cost of the upgrade to generators — then it would not be straightforward to use the cost/value of RECs to assess the relative efficiency of transmission upgrades in any event. The relevant question is how the cost/value of the incremental RECs would be affected by the transmission upgrade. In order to forecast the change in the cost/value of RECs that is caused by an upgrade it would appear necessary to forecast the difference in the cost of different renewables generators, which would then offer no advantage over estimating the reduction in generation costs directly.

[20] In the example above, if the generator in Location 1 paid for the incremental transmission cost of $10/MWh, then the required subsidy for the project – and hence the cost/value of RECs – would rise to $40/MWh.