EnergyAustralia's submission to

Australian Competition &
Consumer Commission

Revised Transmission Capital Investment Program 2004-2009

29 October 2004

Energy

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EXECUTIVE SUMMARY

EnergyAustralia submits this revised transmission capital investment program in accordance with the ACCC's Draft Decision concerning the Statement of Regulatory Principles (Draft SRP) including the proposed changes to the capital investment framework and the ACCC's more recent proposals for the treatment of excluded projects.[1]

EnergyAustralia is also participating in the consultation on the draft SRP and in its submission on that subject, outlines its views on the suite of changes proposed by ACCC. EnergyAustralia is disappointed that the application of a price cap has not been considered as part of the consultation and review process. A price cap could deliver significant economic benefits and promote greater efficiency than is delivered by the current revenue cap framework.

This submission focuses on the ACCC's proposed changes that relate to capital investment. It also contains comments on outstanding issues that remain from the ACCC's draft determination for EnergyAustralia's transmission revenue determination for 2004-2009.

The proposed capital framework

EnergyAustralia remains fundamentally opposed to the introduction of a *firm* ex-ante cap on capital expenditure if efficient expenditure at a level above the cap is not recognised. We have concerns that the framework is inconsistent with the Code and assert that any framework that fails to recognise efficient investment is not in the long term interests of customers and shareholders.

The new framework has fundamentally changed the risks borne by TNSPs and the regime itself is still being developed and as such the risks of the framework are difficult to quantify until the regime is set down with certainty. Accordingly, EnergyAustralia's capital forecasts are likely to be impacted by material changes in the regulatory framework that may result from the parallel consultation process being conducted in relation to the SRP. EnergyAustralia maintains its opposition to the regulatory principles being reviewed at the same time as they are being applied to its business, and strongly believes that any significant changes to the framework through the SRP process must be the subject of further consultation with EnergyAustralia.

EnergyAustralia's understanding of the new capex incentive framework is outlined in this document, and is the basis upon which the new capital forecasts have been developed. In particular in order to provide some level of acceptability to the ex ant approach the mechanisms identified ie excluded projects, off-ramps, linkage of the firm cap to price indexes etc are essential.

In addition, EnergyAustralia submits a number of proposals that we believe address areas of heightened risk for TNSPs. We outline proposals that we believe will assist in the practical application of the framework. Our proposals focus on the process for approving excluded projects, and use of the off-ramp mechanism. The proposed capital program assumes that these mechanisms will apply during 2004-2009.

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[1] *Incentivisation of excluded projects*, ACCC document received by EnergyAustralia on 1 October 2004.

1 CAPEX INCENTIVE FRAMEWORK

The ACCC has proposed a change to the capital investment framework. The most significant change is a move from an ex-post review of capital expenditure for prudence and efficiency, to an ex-ante review of projects and the establishment of a firm cap for capital spending. The framework is essentially asymmetric with the lower of actual spend or the cap itself being included in the RAB. Any capital expenditure over the firm cap will not be recognised by the regulator as prudent and therefore will not receive a return in the future.

EnergyAustralia believes that the case for fundamental changes to the framework has not been adequately made. In our submission in response to the capex incentive framework discussion paper released in March 2004, EnergyAustralia argued that the existing framework, while not ideal, does not need to be completely overhauled in favour of an untried framework created in haste. In fact, EnergyAustralia argued that incentives already exist in the current framework that encourage efficient investment outcomes by TNSPs.

1.1 THE CASE FOR CHANGE TO EX-ANTE

1.1.1 NSW Transmission investment during1999-2004

The ACCC has stated in various forums that the over-spend in NSW on transmission capex during the 1999-2004 period prompted it to rethink the capital investment framework. EnergyAustralia does not believe that spending capex over the amount allowed in the initial determination signals a failure of the framework. Instead, EnergyAustralia would argue that such overspend is likely to be the result of a range of factors including the robustness of the initial forecasts, whether forecasts for demand growth were accurate in each geographic area, movements in GDP, changes to regulations, conditions on planning approvals, better information on asset condition, environmental considerations and the experience of utilities responding to regulatory regimes. EnergyAustralia believes equating over-spend to framework failure is too simplistic.

EnergyAustralia believes that the criteria for changing the capital investment framework should refer to the certainty of investment, and the flexibility of allowing a business to innovate and choose the most efficient projects. It should not be based on wishes to minimise infrastructure investment overall or minimise resources required to regulate it.

The ACCC argues that the existing ex-post framework exposes TNSPs to significant investment uncertainty. EnergyAustralia agrees and would argue that the absence of explicit criteria to assess prudent investment is a key source of this uncertainty. The absence of explicit criteria effectively provides full discretion to the regulator to question all investment and planning decisions ex-post with the potential for some investments to not be accepted as prudent and therefore not be allowed a return. This level of risk is unacceptable to EnergyAustralia.

EnergyAustralia supports a framework that makes investment criteria explicit and that provides discretion to the business to determine priorities and the appropriateness of investments.

1.2 THE PROCESS OF CHANGE

The ACCC's proposed capex incentive framework provides explicit investment criteria and allows investment discretion. In this respect it has EnergyAustralia's support. However, the regime itself is still being developed and as such is difficult to support in full until such time as it is set down with certainty.

EnergyAustralia has long held the view that the concurrent assessment of EnergyAustralia's revenue cap for the 2004-2009 period and the review and redesign of the capital investment framework represents a failure of process by the ACCC. Despite raising these issues at the outset, the ACCC has continued on its path to redraft the Statement of Regulatory Principles and redesign the framework whilst applying it in practice.

EnergyAustralia has reassessed its capital strategy in light of the ACCC's Draft Decision concerning the Statement of Regulatory Principles (Draft SRP) and its more recent proposals for the treatment of excluded projects.[2] EnergyAustralia believes that the ex-ante framework proposed by ACCC has potential advantages over the current ex-post review in some limited instances. However, the increases in risk for EnergyAustralia will require utilisation of both the excluded projects and off-ramp provisions before EnergyAustralia believes the risks inherent in the frameworks are equivalent. Notwithstanding, EnergyAustralia is not convinced that the approach proposed by ACCC of not allowing expenditure over the cap is consistent with the Code. In particular, EnergyAustralia believes that a framework that has at its core the proposition that prudent and efficient investment may not be recognised in future regulatory decisions if it exceeds the firm cap is inconsistent with the Code.

The following section outlines EnergyAustralia's understanding of the new capex incentive framework, and is the basis upon which the new capital forecasts have been developed. The capital program is outlined in section 3.

EnergyAustralia then goes on to outline its concerns regarding the ex-ante framework and puts forward a number of proposals that we believe would address areas of heightened risk for TNSPs. We also outline proposals that we believe will assist in the practical working of the framework. Our proposals focus on the process for approving excluded projects, and use of the off-ramp mechanism.

EnergyAustralia notes that subsequent changes to the framework that impact the balance of risks borne by TNSPs within the framework, such as any proposed changes resulting from the separate SRP process, will impact EnergyAustralia's capital forecasts and therefore must be the subject of further specific consultation with EnergyAustralia.

1.2.1 Code compliance of ex-ante framework

EnergyAustralia is concerned that the ACCC's ex-ante framework may not be consistent with the Code. EnergyAustralia has sought legal advice and has been advised that there are a number of aspects of the ACCC's framework that appear inconsistent with the Code's objectives. In particular, we believe that because the framework contemplates the exclusion of actual efficient investment (above the ex-ante cap) from the asset base, it cannot be said that the framework has as one of its objectives the provision of a fair and reasonable return on

[2] *Incentivisation of excluded projects*, ACCC document received by EnergyAustralia on 1October 2004.

efficient investment. Therefore, EnergyAustralia would argue that the capex incentive mechanism is inconsistent with the Code.

Furthermore, we would argue that the regulator at the next reset should determine on a prospective basis the required revenues given actual efficient investment in the previous and prior periods and anticipated or forecast efficient investment for the next period. On this basis, the exclusion of efficient investment above the ex-ante cap would not provide a fair and reasonable rate of return on efficient investment on a prospective basis and would be directly contrary to what is provided for in clause 6.2.2(b)(2) of the Code. In fact, EnergyAustralia's advice suggests there is nothing in clause 6.2.2(b) that would justify the exclusion of actual efficient investment in the RAB for the next control period and there is no other provision in the Code which would support such an outcome.

EnergyAustralia acknowledges that the Code also requires the ACCC to use incentive based regulation. However, we believe that the objective of incentive based regulation under the Code is to promote efficient investment, not inefficient low cost under-investment as could arguably become the case under the ex-ante framework. EnergyAustralia believes that the exclusion of actual costs above the estimated level appears to actually undermine efficient investment incentives rather than promote an environment where businesses reveal their efficient costs.

EnergyAustralia's proposal

EnergyAustralia believes that the ACCC is obliged to recognise spending above the cap, should it eventuate, at each subsequent review in order to ensure that the framework is consistent with the Code.

1.3 INCENTIVES WITHIN THE CURRENT EX-POST FRAMEWORK

The ACCC has put forward its ex-ante framework because it is required under the Code to regulate TNSPs using incentive regulation. The ACCC has decided that the incentive properties of the existing framework are not sufficient to drive optimal investment outcomes and has therefore proposed an overhaul of the framework.

EnergyAustralia believes that the ex-post framework has some very strong incentives inherent in it and that there has not been an appropriate consideration of these incentive properties, and therefore the incremental benefit of applying a new framework. This section explains the incentive properties of the ex-post framework.

1.3.1 Capital investment

Under the ex-post framework a revenue path is established for five years on the basis of the building blocks – operating and maintenance costs, return of capital, and a return on existing capital investments. A TNSP invests in its network in response to various investment drivers and at the end of the five year period demonstrates to the regulator the prudence and efficiency of its investments over the period. Once prudence and efficiency has been demonstrated, the Regulator includes the spent capital in the regulated asset base which forms part of the following five years' revenue stream.

If a TNSP is unable to demonstrate prudence of the investment, the regulator may not recognise the asset in the regulatory asset base, which means that the business receives an NPV loss of the full amount of that investment. This ex-post assessment of prudence is a very powerful driver to ensure that the business invests appropriately. Ideally, investment criteria would be established to guide investment decisions and to assist the TNSP to provide appropriate information to demonstrate prudence at the review.

If a TNSP invests less capital than it has been allowed by the regulator, it is able to keep the difference between the revenues calculated on a higher expenditure base and those from the resulting lower expenditure base. This incentive to achieve efficiency gains by allowing businesses to retail any profits resulting from lower expenditure is at the core of CPI-X incentive regulation. At the time of the subsequent review, the TNSP must demonstrate prudence of its investments and only the prudent spend will be recognised in the asset base moving forward.

If a TNSP invests an amount that is higher than that assumed in the revenue cap, the TNSP does not receive a return on that investment for the duration of the period. Not only does investing more than the capital allowance effectively cost the TNSP money and compromise its cashflow position during the regulatory period, a higher level of spending is likely to draw a higher level of scrutiny when reviewed by the Regulator. EnergyAustralia is strongly of the view that the <u>TNSP has no incentive to spend more than the amount allowed under the revenue cap under the ex-post framework</u>.

The recognition of past spending at the time of the review is critical to the ex-post framework and is a very powerful incentive not to overspend. If the regulator recognises past spending and the holding costs (if any) of those investments, the business is revenue, but not cash, neutral. However, the TNSP bears significant risk that the regulator may not accept all projects as prudent. The risk is even higher when the investment criteria has not been made explicit. The business, therefore, has the incentive to ensure that all its spending can be demonstrated as prudent.

If the regulator does not recognise holding costs but recognises the actual higher investment, the TNSP still faces a negative NPV on that investment. In this case, the business has even less incentive to overspend its capital allowance.

The ACCC should recognise that expenditures above forecast levels may happen even when a business is faced with strong incentives to reduce expenditure, but this on its own does not necessarily suggest that the higher investment was inefficient, as is the implicit assumption underlying the ACCC's ex-ante framework. In face, the incentive implicit in the CPI-X revenue cap framework is to make no investments, as each dollar spent results in reduced returns, irrespective of the size of the revenue cap.

1.3.2 The adequacy of the incentives

EnergyAustralia believes that the ex-post framework contains very strong incentives to drive efficiency. EnergyAustralia has recently introduced its capital governance framework to drive greater transparency and accountability of decision making. The framework has been driven by the internal needs for greater transparency of decision making but it will also benefit external stakeholders.

As outlined in EnergyAustralia's SRP submission, EnergyAustralia has also undertaken a major revision of its operating program to better target maintenance activity. The move from a time based to a condition based program will deliver long term efficiencies in the maintenance program and improve condition monitoring and ensure strategic analysis of replacement programs.

In short, EnergyAustralia can demonstrate that it has responded to the existing regulatory framework and therefore believes the incentives in the current framework are sufficient and do not require improvement as suggested by the ACCC. It is too simplistic for ACCC to assume the higher expenditure in the current period represents inefficiency.

1.4 ENERGYAUSTRALIA'S UNDERSTANDING OF THE FRAMEWORK

This section summarises EnergyAustralia's understanding of the ACCC's proposed ex-ante capital incentive framework. This understanding is the basis upon which our revised capital forecasts have been developed. It takes into account the draft SRP released in August 2004 and subsequent information provided to EnergyAustralia regarding the excluded project and off-ramp mechanisms.

Capex efficiency mechanism - firm ex-ante cap

- Ex-ante review of capital projects included in the cap with **no ex-post review**;
- Projects under the ex-ante cap would be specified up front, but the business would have full discretion as to what projects it constructs;
- The cap would be firm. Any spend over and above the cap would not be recognised in the asset base at any stage and therefore would not form the basis of the allowed revenues stream at subsequent regulatory reviews;
- The difference in revenues between the allowed amount and any spend under the cap would be kept by the business for the remainder of the period. However, only the capital invested up to the cap would be included in the asset base moving forward;
- The cap is to be set where possible using probability analysis and scenario modelling; and
- The cap can also be linked to key business drivers such as load growth.

Excluded projects

- Some large and/or uncertain projects may be nominated to be excluded from the cap. The ACCC has set out materiality criteria for such projects as a guide but will also use its discretion to decide which projects should be outside the cap. The ACCC's exclusion threshold is based on whether the expected error of including the project in the revenue line results in a greater than 10% error if the project does not go ahead.
- Excluded projects are those that are identifiable at the time of the review, however, are sufficiently uncertain in terms of timing and scope that it would be unreasonable to include in a firm cap.
- Projects will be excluded at the discretion of the ACCC at the time of the review.
- An estimate of the excluded project's costs will be included in the revenue line in advance, but actual spend on excluded projects will be included in the RAB at the end of the period.[3]

[3] Ibid

- An incentive mechanism will apply to excluded projects. A project specific cap will be agreed prior to the project's construction. The project specific cap will apply for a period of five years which may or may not align to the five year regulatory period.
- If a TNSP spends more than the amount agreed to, it will lost the carrying costs of any overspend. However, the actual cost of the investment is rolled in to the RAB.
- If the TNSP spends less than the cap, the TNSP benefits by retaining the return on any underspend for a 5 year period, with the actual lower cost of the asset rolled in to the asset base.
- This incentive mechanism differs from that which applies to the overall firm cap. In the case of excluded projects, the incentive penalty/benefit is symmetric. Actual cost regardless of whether it is higher or lower than the agreed cap is included in the asset base.

Off ramps

- Off-ramps are designed to address circumstances that are unexpected and unforeseen at the time of the review. Typically off-ramps will include force majeure events or changes in taxation rules etc.
- The off-ramp criteria are to be specified and negotiated between the TNSP and the ACCC as far as is possible at the time of the review. The ACCC propose an annual materiality threshold equivalent to 5% of the average annual capital expenditure (in other words, one percent of the total capex target). The threshold will apply annually and to each off-ramp event. "If the present value of the investment following an off-ramp event exceeds the "threshold", then the full cost will be recoverable from consumers".[4] This is different from the ACCC's previous position, as set out in its draft decision on the SRP, which proposed that an "excess" would apply to each off-ramp event which TNSPs would bear. The "excess" proposal has now been withdrawn.
- "Off-ramp events" can only be invoked by TNSPs – in other words TNSPs will be covered (subject to the event meeting the threshold) against cost increases resulting from off ramp events. However, the off ramp mechanism will not be used to reduce the ex-ante cap should forecast events not occur.[5] This aspect is also different from that proposed in the ACCC's draft decision on the SRP.
- The adjustment of revenues to take account of off-ramp events has not been determined specifically (i.e. annual versus end of period adjustment). However, ACCC proposes that "(t)he TNSP…will be allowed to include the actual expenditure incurred on the off-ramp project during the regulatory period in which the off-ramp occurred…"[6]

1.5 ENERGYAUSTRALIA'S CONCERNS

1.5.1 A framework developed in haste

EnergyAustralia is concerned that the ACCC has hastily put together its new regulatory framework. And it is within the context of a changing set of rules that EnergyAustralia and TransGrid have been asked to develop their respective capital programs. EnergyAustralia is

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[4] ibid, p10.
[5] Ibid, p10.
[6] Ibid, p11.

concerned that aspects of the framework are still being developed whilst the framework is applied to TNSPs revenues in NSW for the 2004-2009 period.

1.5.2 Impacts on a relatively small portfolio

EnergyAustralia has a small portfolio of projects relative to most TNSPs and particularly when compared to TransGrid. The smaller the portfolio, the less likely it is that cost increases on a particular project can be recovered within the cap.

This situation is made worse when there are large and uncertain projects within the small portfolio, and further compounded by the difficult construction environment (i.e. a dense urban/ CBD setting) faced by EnergyAustralia. The ACCC itself has realised the ramifications of this fact and has adjusted its framework to allow specific projects to be excluded to take account of their uncertainty.

The use of the excluded projects mechanism however, leads to an even smaller portfolio of projects to be included under the cap, therefore again, reducing the ability of EnergyAustralia to compensate for any unforeseen cost increase on any project.

The ACCC has indicated that it will set an ex-ante cap in a conservative manner. The ACCC's recent paper "*Incentivisation of excluded projects*" says that where an asymmetric incentive mechanism is applied the ACCC must "(set) the allowed expenditure above expected efficient expenditure level(s)".[7]

EnergyAustralia is pleased that the ACCC has acknowledged the relative disadvantage that could result from the ex-ante framework, but is concerned that no detail has been provided as to how this might be done in practice.

EnergyAustralia's proposal

EnergyAustralia therefore expects ACCC to set its cap conservatively at the level at which the business has a very high degree of confidence that its spending will not increase over the cap. This must, by definition, be higher than the mid-point estimate provided by EnergyAustralia for its capital program in 2003.

1.5.3 Probabilistic analysis

The ACCC has indicated it expects TNSPs to develop their capex proposals using both scenario modelling and probability analysis. EnergyAustralia is concerned that there is insufficient time to adequately undertake either of these processes to develop capital programs for the 2004-2009 review.

Furthermore, EnergyAustralia is at a loss as to how it might develop scenario modelling or probabilistic analysis when a significant proportion of its program has the potential to be impacted by the investments made by TransGrid. Given that TransGrid is undertaking a similar process concurrently with EnergyAustralia and may submit its revised capex program after EnergyAustralia's submission, it is difficult to see how EnergyAustralia could take account of TransGrid's analysis when it becomes available.

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[7] Ibid, p5.

EnergyAustralia's proposal

EnergyAustralia intends to exclude projects that are the subject of joint planning or that are likely to be significantly impacted by joint planning with TransGrid. EnergyAustralia intends to exclude all jointly planned projects regardless of the projects' size. This is because any requirement to reach a threshold for excluding the project could lead to projects being planned in a way to ensure that EnergyAustralia's portion of expenditure is sufficient to trigger an excluded project, regardless of whether the project plan that eventuates is the optimal project design.

EnergyAustralia therefore proposes that all projects subject to joint planning be excluded from the cap regardless of the project's impact on the revenue cap. In early discussions, the ACCC has indicated its agreement with this position.

EnergyAustralia has undertaken some analysis with regard to the likely timing of projects and has assigned a probability with respect to the likelihood that the project timing will change from that included in the program. The purpose of this analysis is to demonstrate the extent of flexibility that EnergyAustralia may have within the period.

1.5.4 Approval process for excluded projects

The ACCC has set out a process for the approval of excluded projects. The process is as follows[8]:

> **Step 1**
> The TNSP notifies the ACCC of its intention to invoke an "excluded project event". This should occur when the TNSPs becomes certain that investment in the excluded project will be needed. The ACCC then decides whether a bona fide "excluded project event" has occurred and notifies the TNSP accordingly. This is intended to provide certainty that the ACCC will recognise the investment as an excluded project – i.e. in addition to the investment provided in the main ex-ante incentive. This means that the TNSP can proceed to develop project designs, seek environmental and other approvals with the knowledge that, subject to the incentive, the costs will be recognised by the ACCC. The TNSP should then apply the Regulatory Test (if applicable) or other investment appraisal processes to the investment in the excluded project. A key point is that while primary responsibility rest with the TNSP to undertake the project assessment, ACCC staff envisages that this assessment will be conducted in consultation with the ACCC. This means that ACCC staff expects to closely monitor key assumptions and the analytical approach adopted with the TNSP. ACCC staff propose to adopt this approach partly to ensure that incentives can be expeditiously developed. This recognises that in setting an incentive for investment in the excluded project the ACCC will need to cover the same ground that would have been covered in the Regulatory Test. It will be possible to avoid unnecessary duplication by consulting with the ACCC at the time that the TNSP undertakes this evaluation. ACCC staff expect to undertake consultation with interested parties throughout the assessment. This may involve consultation over and above that already provided for in Chapter 5 of the Code. ACCC staff consider that an indicative time frame of four months would be appropriate depending on the length of time required to complete the regulatory test process in accordance with the Code.
>
> **Step 2**
> After completion of the Regulatory Test process in accordance with the Code (including any appeals), the ACCC will establish an incentive for the excluded project. The incentive will specify:
>
> - when the incentive is to begin (under the preferred incentive design it ends five years from the date the incentive begins to apply);

[8] Ibid, p8.

- the profile of target annual expenditure on the excluded project;
- the calculation of the annual regulated revenue to cover depreciation and return on the investment in the excluded project on the basis of the annual investment allowances determined by the ACCC;
- the calculation of the closing Regulatory Asset Base for the investment in the excluded project at the end of its five year incentive.

Step 3
The TNSP invests in the excluded project. The appropriate adjustments to the closing Regulatory Asset Base and the capex allowance for the following period will be made at the re-set of the TNSP's revenue cap. Although the necessary adjustments could be made during the regulatory period with amendments to the Code.

EnergyAustralia believes it to be crucial that the process for approval of excluded projects be as simple and streamlined as possible. The relative ease/complexity of the process will heavily influence the success or otherwise of this part of the framework, and therefore the inherent risks of the framework overall. If the process outlined for excluded projects is cumbersome, time consuming, characterised by long delays to decisions and costly, EnergyAustralia believes that the benefits of this mechanism being contained in the framework will be lost. EnergyAustralia believes that maintaining this feature within the framework is a critical tool to balance the risks inherent in the new capex framework. EnergyAustralia has an incentive to ensure that the approval mechanism is streamlined, easy to comply with and minimises regulatory cost imposts and micro-management.

EnergyAustralia's proposal

EnergyAustralia believes some further clarification needs to be provided, especially with regard to the ACCC's stated intention to "closely monitor key assumptions and the analytical approach adopted".

EnergyAustralia believes that its governance procedure should deliver the majority of information that is likely to be sought by ACCC in its approval process for excluded projects. The governance procedure (Appendix 25) has been developed in response not only to requirements for significantly increased investment programs, but also in response to the need for greater transparency of decision making both internally and to external stakeholders.

EnergyAustralia intends to utilise the milestones that are delivered by the governance procedure as an appropriate starting point for the approval process for excluded projects. The alignment of the regulatory approval process for excluded projects with the internal governance regime will limit the administrative complexities and costs involved to gain approval for excluded projects, and would match the information generated for internal decision makers with that available to external regulators.

The governance procedure outlines a 5-step process by which projects (and investment programs) will be developed. By following the step by step process, EnergyAustralia can ensure that appropriate assessment of options has taken place, including demand side analysis. The procedure ensures that projects do not pass through the "Approval Gates" to the next stage of development until all documentation, consultation and authorisation requirements are met.

1.5.5 Further general concerns about excluded project approval process

EnergyAustralia is concerned that the development timeframe for excluded projects is longer than the ACCC's process outline assumes. The Step 1 set out by ACCC above, is effectively a multi-stage process with the first stage being to identify the need for the project and to notify the ACCC. The next stage is the development of the project, which could take several months or years depending on the project. It is within this second stage that options are developed, a specific option is chosen, demand side analysis is conducted, specific designs developed, EIS conducted, and planning authorities received etc.

Throughout this phase, decisions are made that allow the project to be progressed. By the time the Regulatory Test is completed, the project is ready for construction and in fact, it is often too late to reconsider an alternate project, particularly if the investment is being driven by demand. EnergyAustralia believes that it will be critical that the ACCC is involved in some of these key investment decisions leading up to the application of the Regulatory Test to ensure that the final option is not required to be re-engineer at too late a stage in the process. Clearly the challenge will be balancing the level of comfort sought by ACCC through direct involvement in the process compared with the increased regulatory intervention that will necessarily increase compliance costs and project development times.

EnergyAustralia proposes that the ACCC's close monitoring of projects should involve a process of incremental approval of planning decisions. The incremental approval process will require regulatory commitment to participate in the planning and development of projects. It will provide hands on experience of transmission planning and demonstrate the lengths TNSPs take to optioneer solutions and address performance risk. It will also demonstrate the level of information available to businesses when they make investment decisions. Most importantly, an incremental approval process will require the regulator to act consistently with decisions it has made in the past and will effectively remove the regulator's ability to look at investments with 20:20 hindsight and discount the prudence of investments. This has clearly been the case in the Mountain & Associates report regarding TransGrid's CBD augmentation. Perfect hindsight is not a luxury afforded to transmission planners when making ex-ante investment decisions. It is therefore not appropriate that it be afforded the regulator.

EnergyAustralia believes that the ACCC should provide approval for planning decisions, however, it should be such that it ensures the ACCC will not renege on previous decisions at the next reset. EnergyAustralia believes it is up to the ACCC itself to determine the appropriate governance arrangements to grant such approvals. It is critical that the approval mechanism minimises delays to ensure that reliability is not negatively impacted.

With regard to the ACCC's proposed process (outlined in the box above), EnergyAustralia believes that a four month process is appropriate to allow the ACCC to provide its final assessment following the application of the Regulatory Test.

1.5.6 Provisions for excluded projects

EnergyAustralia sought clarification from the ACCC as to how provisions for excluded projects will be incorporated in the revenue line at the time of the revenue reset. The ACCC indicated that it did not expect to make a provision in the revenue line for all excluded projects, particularly those projects that are highly uncertain as to whether they would in fact be constructed within the period. ACCC indicated that where the likelihood of the project proceeding was high, it might be appropriate to include some provision for the project in the revenue line.

EnergyAustralia believes that provisions in the revenue line are crucial to ensure that the business can continue to operate without a compromised cashflow position. EnergyAustralia also believes that the cashflow position of the business needs to be considered in isolation of other non-prescribed activities that the business may conduct.

However, EnergyAustralia recognises that customers should not pay for projects that are not being constructed. Therefore, there is a fine balance to be struck between supporting the commercial needs of the TNSP and ensuring that customers do not face higher than necessary prices for transmission services.

EnergyAustralia's proposal

EnergyAustralia believes that where projects are highly certain to go ahead within the period, provisions must be included in the calculation of the revenue requirement. Where cost/scope of the project is uncertain, it is appropriate that a provision based on a mid point estimate be included. EnergyAustralia believes that accepting a mid point estimate rather than a high estimate balances the needs of both the business and the consumer. Consumers do not pay for the highest cost option, but TNSPs have the majority of their costs met within the period.

In cases where projects are very uncertain as to whether they will in fact go ahead (this is likely to be in cases where projects are scheduled towards the end of the period), EnergyAustralia accepts that it would be difficult to justify a provision in the revenue line. However, where the project does go ahead towards the end of the period, the next revenue reset must include a provision for the project.

It should be noted that the provision in the revenue line is not necessarily the same as the estimate agreed to by ACCC during the excluded project's approval process. It is against this latter estimate that the incentive mechanism is measured.

1.5.7 Inclusion of excluded projects in the asset base

EnergyAustralia sought clarification from the ACCC on how it intends to include the expenditure associated with excluded projects into the asset base. ACCC indicated that it intends to roll-in actual spend on excluded projects at the revenue reset that follows the end of the 5 year incentive mechanism applied to the project. Thus, where an excluded project begins in one period and continues through to the next period, the expenditure on that project would not be incorporated in to the asset base until the end of the second regulatory period. If a project began early in the regulatory period and ended early in the following period, 8-9 years would pass before the expenditure would be included in the asset base. Figures 1 and 2 (following page) demonstrates the ACCC's proposed treatment of excluded projects.

EnergyAustralia does not believe it is reasonable for TNSPs to be required to wait such a long time for expenditure on excluded projects to be included in the asset base. The carrying costs of some excluded projects may be extremely high, particularly where the project is large and where no provision has been made in the revenue line for the project. EnergyAustralia believes that it is not a reasonable allocation of risk between the TNSP and its customers in this regard, nor is it sustainable from a cashflow perspective for TNSPs to carry the costs of non-provisioned investments for two regulatory periods. Furthermore, the cashflow position may be compounded if several non-provisioned excluded projects are being constructed at the same time.

EnergyAustralia believes that the requirement to wait until the end of the 5 year incentive mechanism for excluded projects before adding actual spend to the asset base is not appropriate. Under the current ex-post framework, capital investment on projects regardless of whether the project is completed or not, is reviewed for prudence and rolled in to the asset base. EnergyAustralia believes that the new framework should provide a similar outcome. It is not appropriate for businesses to wait up to twice as long before the costs of investments are recognised simply because of the operation of a construct (the notion of an excluded project) which is of the ACCC's making. EnergyAustralia strongly believes that the ACCC's new framework should meet the needs of the business and of other key stakeholders as a priority and mechanisms that compromise the business's ability to operate in a commercial fashion should not be considered in the framework.

EnergyAustralia's proposal

EnergyAustralia believes that all spending on excluded projects should be recognised at the time of the next regulatory reset regardless of whether the 5 year incentive mechanism for the individual excluded project has ended. EnergyAustralia can see no reason as to why the incentive mechanism cannot continue to apply to spending in the following period, and that at the end of the period any remaining expenditure be recognised.

Figure 1 - ACCC's proposed framework for an excluded project

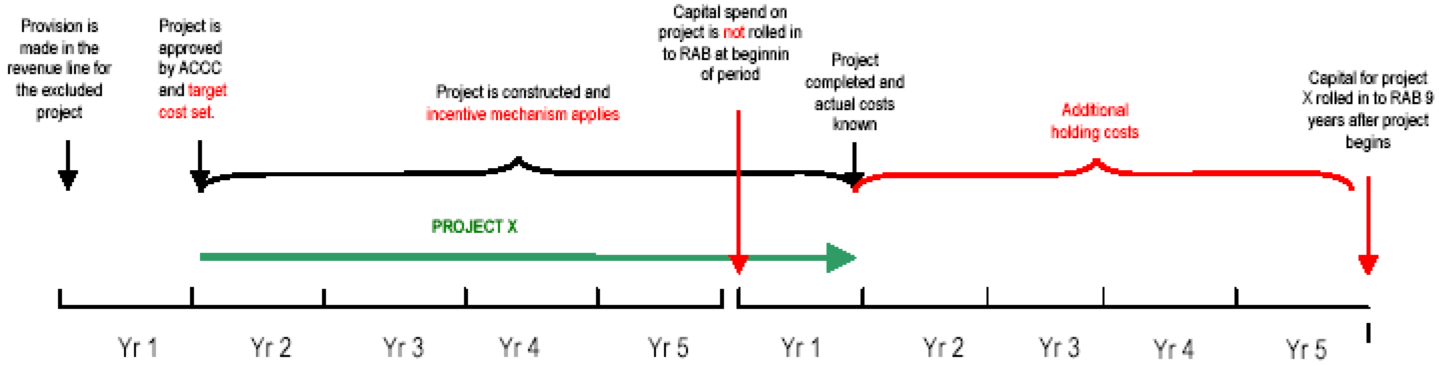
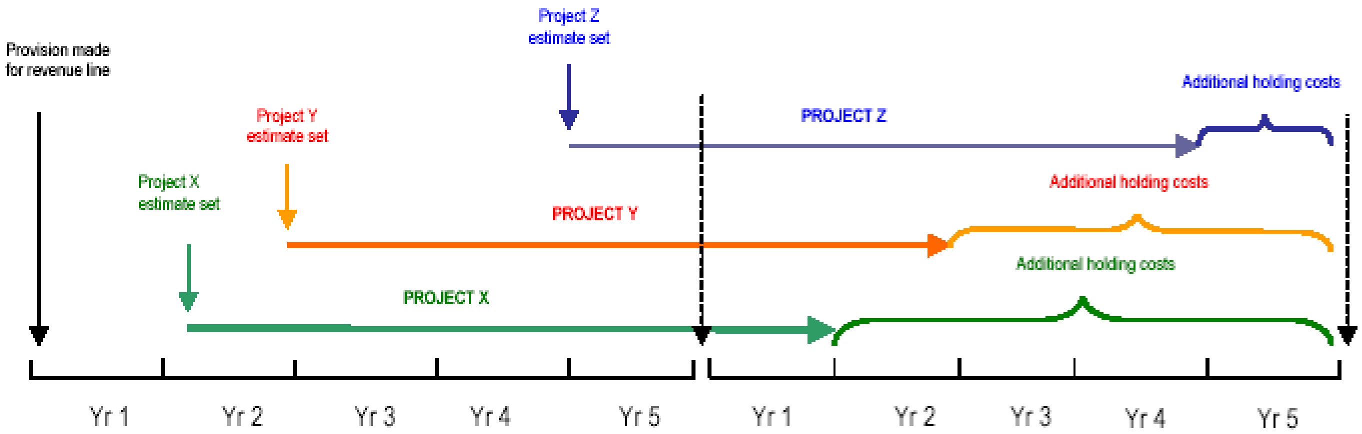


Figure 2 - Framework with more than one excluded project



1.5.7 Off-ramps

The off-ramps mechanism outlined by ACCC in its draft SRP is still somewhat unclear. It is understood that the mechanism allows for unforeseen circumstances that cause a material change in required capital expenditure to be taken into account through a reconsideration of the capital program, including the firm cap. It is understood that such circumstances should be agreed to up front and that a materiality threshold of five percent is to be used to trigger an off-ramp.

The ACCC in its "*Incentivisation of excluded projects*" paper (Appendix 24) includes the ACCC's latest thinking regarding off-ramps which directly contradicts what is contained in the draft SRP.

"(T)he DRP provides for an "excess" for the recovery of expenditure related to off-ramp events equivalent to 5% of the total capex allowance for the regulatory period. This means that the TNSP is required to cover the first 5% of any investment following an "off-ramp" event. It also provided that off-ramp events" could be invoked by TNSPs, the ACCC or third parties."[9]

The ACCC now propose the following:

- The "threshold" should be reduced from 5% of the total capex allowance during the 5 year regulatory control period, to an annual "threshold" equivalent to 5% of the average annual capex expenditure (in other words one percent of the total capex target). The threshold will apply annually. This means that although investment following an off-ramp may exceed the target in any one year, it will need to be reset for all subsequent years;
- If the present value of the investment following an off-ramp event exceed the "threshold", then the full cost will be recoverable from consumers;
- "Off-ramp events" can be invoked by TNSPs – in other words TNSPs will be covered (subject to the excess) against cost increases resulting from off ramp events. However, the off-ramp mechanism will not be used to reduce the ex-ante cap should forecast events not occur.

EnergyAustralia welcomes the ACCC's view that a threshold based on an annual spend should be used to trigger an off-ramp rather than a 5% trigger over a 5 year period.

The ACCC states in its paper "*Incentivisation of excluded projects*" that it does not intend to apply an incentive mechanism to projects triggered by off-ramps. EnergyAustralia agrees that events that trigger off-ramps are not appropriate to have an incentive mechanism applied. However, EnergyAustralia is not clear as to how the ACCC would treat off-ramps. It appears that ACCC intends to provide a target for expenditure, but that if circumstances drive costs above that target level, the TNSP is free to come back to ACCC to review the target. Once completed, the actual spend will be rolled in to the asset base.

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[9] Ibid, p 10.

EnergyAustralia's proposal

In its paper *"Incentivisation of excluded projects"*, the ACCC states that it would only review the agreed off-ramp target in extreme circumstances. EnergyAustralia proposes that the wording be changed to reflect "justified" rather than "extreme" circumstances.

EnergyAustralia proposes that off-ramps be rolled in at their actual cost including holding costs. This is consistent with the ACCC's position that no incentive mechanism be applied to off-ramps.

1.5.8 Suggested off-ramps for EnergyAustralia

The ACCC has suggested that off-ramps be agreed to up front with the TNSP. EnergyAustralia suggests that this is an ideal scenario but that it is likely to be impossible to identify all possible events that could trigger an off-ramp. While some events are clearly imaginable, there is also a possibility that completely unforeseen events could take place which must also be considered within the off-ramp category.

EnergyAustralia's proposal

EnergyAustralia suggests that an non-exhaustive list of events that could be considered in the off-ramp category be identified. EnergyAustralia suggests that the following non-exhaustive list of events should be considered as off-ramps:

- Changes in demand that drive material changes to the capital program;
- Changes in legislation that drive material changes to the standards or construction or operation of the network;
- Material exchange rate variations;
- Unforeseen customer connection;
- Change to planning standards as a result of external factors, including legislation, that drive changes to the capital program;
- Response to a terrorism event.

1.5.9 Off-ramps and pass through

The ACCC has put forward the off-ramp mechanism as a way of addressing unforeseen circumstances that have significant implications for the capital program. As outlined above, the off-ramp mechanism is triggered if the ACCC agrees the circumstances fit the criteria, and if the resulting investment represents one percent of the total capital program (or five percent of the annual capex allowance). The ACCC also proposed in its Draft SRP that a pass through mechanism apply to the regulatory framework, where subject to a set of criteria included in the Pass Through Rules, the costs of unforeseen events that are outside the control of the TNSP but that materially effected the costs borne by the TNSP, would be able to be passed through.

EnergyAustralia is unclear what the relationship between the Pass Through Rules and the off-ramp mechanism are. It appears that many of the defined Pass Through Events listed in the draft Pass Through Rules could in fact have ramifications for capital investment, and therefore that such events could trigger both mechanisms.

It is important that the Pass Through Rules remain intact as they are a central part of the balancing of risks within the current regulatory framework, particularly where opex is concerned. However, it is also important that the purpose of the off-ramp mechanism is clearly defined and made explicit so that it is clear to TNSPs and other stakeholders whether the off-ramp mechanism actually offers any flexibility in addition to what is already provided by the Code (in terms of reopening the revenue cap to take account of material error or false information) and what is provided for in the Pass Through Rules.

EnergyAustralia considers it very important that the ACCC consider the balance of risks that the ex-ante framework presumes and that the additional risks faced by TNSPs under a firm cap arrangement are compensated through a mechanism in the investment framework to cover the more risky investment climate.

1.5.10 Customer connections

EnergyAustralia operates largely as a distribution network. However, part of its network is defined as a transmission network due to the strict application of the definition of transmission contained in the Code. While most customer connections occur at the distribution level, there are an increasing number of high voltage connections being requested by large industrial customers in the Sydney and Hunter regions.

There are a number of customers that have discussed connection options with EnergyAustralia and which could connect to the network in the 2004-2009 period. These are outlined in detail in Section 3.5. Most of the customer connections are at the planning or inquiry stage only and have no firm scope of costs associated with them.

Generally, when a customer connects to the network the customer covers part (or all) of the cost associated with connection. However, customers do not pay for shared assets. If the customer connection were to take place in an area where there is sufficient transmission network capacity, it is likely that the customer's contribution to that connection asset could meet the total costs of the connection (ie only customer specific connection assets would be required). However, in many cases a customer requests a high voltage connection in a part of the network where there is neither capacity at the connection point nor capacity further upstream to meet the customer's connection requirement. In such circumstances, the customer's contribution is likely to fall far short of the required network investment (as the contribution does not cover assets that could be shared).

EnergyAustralia seeks clarification as to how the ACCC's ex-ante cap caters for customer connections. It appears that such unforeseen customer connections would fall in to the off-ramp category. However, for the event to be triggered, the customer connection costs would need to be above the 5% materiality threshold. Where the cost of connecting a customer did meet the 5% threshold, the regulator would be able to review the revenue cap to ensure that the TNSP received an appropriate return for meeting its obligations to connect. However, it is possible that an individual unforeseen customer connection could cost less than the threshold and therefore would not be captured at all by the revenue cap effectively resulting in the TNSP not being paid for meeting its obligations under the Code to connect that customer.

In some cases, a customer has already inquired about a connection and therefore the event would be not be strictly 'unforeseen'. In this case, it would appear that the connection would be more appropriately characterised as an excluded project – foreseeable, has the potential to be significant but is uncertain in terms of scope and cost.

As mentioned above, EnergyAustralia has outlined a number of customer connections that could be made to the network in the 2004-2009 period. However, at this stage, none of the connections are certain to go ahead.

EnergyAustralia's proposal

EnergyAustralia believes that it would be prudent to treat all its customer connections the same, regardless of whether the project is foreseen or unforeseen. EnergyAustralia does not believe that it is appropriate that different thresholds, different incentive mechanisms and different approval processes should apply to customer connections simply because the TNSP had knowledge of them or not at the time it made its submission.

EnergyAustralia would argue that it is not appropriate that a threshold or an incentive mechanism be applied to customer connections. TNSPs face Code obligations to connect customers to their network and the costs of meeting these obligations should be recognised by the regulator as prudent and necessary investment. As mentioned above, EnergyAustralia's policy is that customers pay for all dedicated assets and that EnergyAustralia pays for shared network assets.

Given the obligation to connect customers, EnergyAustralia does not believe it is appropriate that a threshold apply before such spending is recognised. The size of the customer connection does not lessen or increase the obligation faced by EnergyAustralia to connect customers and it is not reasonable for a TNSP to bear the costs of meeting these requirements.

EnergyAustralia proposes that no allowance be included in the revenue line for customer connections that it can foresee at this time. However, should such an event occur, EnergyAustralia proposes that the actual cost of the investment (less customer's contribution) be included in the RAB (including holding costs) at the end of the period. This will ensure that EnergyAustralia receives an NPV neutral return for investing in shared assets that result from customer connections. It also ensures that customers at large do not pay for connections that may not take place within the regulatory period.

EnergyAustralia believes that it is appropriate that a specific mechanism be applied for customer connections as the TNSP itself has no control over the location of the customer or the timing of the customer's connection request. Furthermore, as the TNSP has no discretion as to whether to supply the customer or not, it is appropriate that the TNSP is paid in full for the costs of connecting that customer.

2 GOVERNANCE PROCEDURES

EnergyAustralia has identified a need to improve the transparency of decision making and the tracking of project expenditure. EnergyAustralia has implemented a new governance framework to ensure that processes for making investment decisions are transparent and deliver prudent and efficient investment decisions.

2.1 THE NEW GOVERNANCE FRAMEWORK

The framework is designed to give appropriate attention to the early stages of the investment process. The cost of a project, including operation and maintenance, is largely determined before it is executed. As a result, the greatest scope for managing the costs of a project is in the development and planning stages. Typically, two-thirds of the influence on investment outcomes is determined by assessment and selection, even though only a small proportion of the actual spend occurs in these stages.

The investment governance process is characterised by five stages:

1. Identify Issues

The first stage involved the identification of issues and gathering of all data required to inform the investment process. This data is then analysed and will result in an "Identification of Needs" document that outlines anticipated network requirements in terms of:

- Capacity constraints;
- Reliability improvements
- Duty of care;
- Equipment condition;
- Customer connections.

The Identification of Needs occurs represents the foundation of the investment framework. This process identifies the potential investment needs by forecasting instances where network performance will fall short of the desired standard. Individual issues are analysed to determine related issues and packaged into projects for which options are developed in the following stages.

In the case of demand projects a "Statement of Needs & Initial Network Solution" is prepared which in addition to the "Identification of Needs" contains an initial system solution with planning estimates. The purpose of this to provide a benchmark target cost framework performance investments within which demand-side and non-network solutions can be developed. This benchmark costs will be used in screening projects as to their suitability for a non-network option investigation.

2. Develop Feasible Options

This stage involves the development of feasible options to address the “Identification of Need” and the “Statement of Need & Network Options” produced in the first stage.

“Project Option Studies” are developed detailing a number of feasible options and their likely costs. Including both demand management and network options. These project option studies documents how the options were developed, reviewed and the criteria used to identify the preferred option. It should be noted that the economic assessment approach used to rank options must be consistent with the economic decision making methodology prescribed for the final decision, based on the size of the project.

The outcome of this stage is an “Instruction for Project Development” calling for Project Offers from appropriate service providers. This instruction may call for the development of one or more selected project options. These may include variations on a single option or multiple unrelated options.

3. Plan and Justify

This stage involves the preparation and analysis of the “Project Offer” submitted in response to the “Instruction for Project Development”.

“Project Offers” should include details of costs, project delivery timetables and project risks for each project option and variation.

The project offers will be review for compliance with the required technical outcomes and investment evaluation guidelines. Where the project offers do not meet the requirements or cost estimates differ significantly from planning estimates the selected options may need to be reviewed to ensure that they still represent the preferred option.

The outcome of this stage is a “Justification for Project Selection” and “Authorisation of Selected Project”.

An “Independent review of Project Selection” will also be conducted for projects greater than $10m.

4. Execute Project

The Execution stage commences with the preparation of the “Instruction for Project Evaluation”. The outcome of this stage is the “Project Completion & Acceptance Report”. This stage involves the delivery of the project. Performance in executing the project is assessed on the basis of delivery of the project in accordance with the defined scope, the program schedule and actual cost compared to authorised expenditure.

5. Operate and Evaluate

This stage involves the operation and evaluation of investment projects. This stage is important since Network revenues is dependent on verifying that investments made are both prudent and represent efficient solutions.

A Post Implementation Review is required for projects with a value in excess of $2m and for those selected by the General Manager – Network.

2.1.1 Program Management

In order to meet shareholder and regulator prudence requirements it is necessary to manage investments both at a program level as well as a project level. At the program level it is necessary to:

- Ensure that programs are prioritised in terms of prudence and efficiency within investment portfolios.
- Identify scope for integrating programs across investment portfolios.
- Prioritise projects in terms of timing.
- Manage program contingency.

The management of investment at the program level mirrors the management at the project level. At the program level strategic plans are developed for each investment portfolio. These strategic plans will be used to develop investment programs for a particular regional, asset or other issue.

2.1.2 Alignment of Governance Procedures to ACCC approval of excluded projects

The ACCC has not detailed a process for approval of excluded projects at this stage. EnergyAustralia believes that the Governance Procedures being put in place are an appropriate basis for such a process which will minimise EnergyAustralia's compliance costs, but will ensure transparency of decision making and ensure consistency between internal and external investment approval procedures.

An excluded project is by definition a project that is uncertain in terms of timing, cost and/or scope at the time of the revenue reset. Under the ACCC's proposed capex framework, such projects are identified up front and are subject to project specific scrutiny at the time the investment decision is being made.

EnergyAustralia's governance procedures provide a structured and transparent format for project assessment. It also provides formal documentation that contains information the regulator will seek to assess the prudence of individual projects or programs. The key documents that emerge from the governance process will address the regulator's concerns in relation to:

- the need for investment;
- the options considered, including demand side initiatives;
- the technical specifications for the selected option; and
- the final project and its delivered costs.
- In specific cases there will also be a post-implementation review.

EnergyAustralia proposes that the documents that outline the need for investment (i.e. “Identification of Needs” and “Statement of Needs & Initial Network Solution” document), the options considered and the technical specifications for the selected option (“Project Option Studies”, “Instruction for Project Development”, the “Project Offer” and the “Justification for Project Selection”) be forwarded to ACCC at the time the documents are generated by the governance process. This will allow ACCC staff to be informed of new information as it becomes available to EnergyAustralia management. It will also allow ACCC staff and/or consultants to raise issues at that time to ensure that EnergyAustralia can address outstanding issues prior to investment decisions being made.

The governance procedure utilises “Approval Gates”, where those accountable for various stages of a project do not allow a project to advance to the next stage until the requirements for that stage have been met. EnergyAustralia believes that the ACCC approval at relevant stages could be made part of the approval process. By providing incremental approval, the TNSP can be certain of the ACCC’s support at each stage of the investment process. Both parties can ensure that the option selected and constructed is indeed the most prudent option based on information available to both the business and the regulator at the time the investment decision is made.

EnergyAustralia believes that if the internal compliance costs can be minimised through having the ACCC’s approval process aligned with our own governance procedures, the benefits of gaining regulatory approval at each stage of the process will far outweigh the potential costs. EnergyAustralia has obligations to maintain a reliable supply to its customers and therefore cannot afford to face a situation where the regulator disapproves a project at a point in time that it is too late in the process to change the project significantly.

The incremental approval process will require regulatory commitment to participate in the planning and development of projects. It will provide hands on experience of transmission planning and demonstrate the lengths TNSPs take to optioneer solutions and address performance risk. It will also demonstrate the level of information available to businesses when they make investment decisions. An incremental approval process will also require the regulator to act consistently with decisions it has made in the past and will effectively remove the regulator’s ability to look at investments with perfect 20:20 hindsight – a luxury not afforded to transmission planners when making investment decisions.

EnergyAustralia believes that it is up to the ACCC to determine the level of signoff that is appropriate for the ACCC to be able to maintain consistency with previous approval decisions (i.e. effectively bind the regulator to its previous decisions in relation to specific investments).

On a practical note, EnergyAustralia believes that the process for approving excluded projects could be streamlined if a mechanism was introduced that provided the regulator with a 30 day timeframe in which to raise issues regarding the planning and development of projects. If no issues are raised within that time, approval of the relevant decision would be deemed to be given.

3 REVISED CAPEX 2004-2009

3.1 NEW CAPEX PROGRAM

3.1.1 Reasons for change – time to consider long-term requirements

The ACCC has delayed its final determination for EnergyAustralia's 2004-2009 revenue cap to accommodate the new capital framework. The delay is necessary if the framework is to be applied, as it is essential that EnergyAustralia and TransGrid reassess their respective capital programs in light of the new framework and the risks contained therein.

EnergyAustralia agreed to assist the ACCC in development of its new framework. We have not endorsed the framework to date, however, we believe that there may be aspects of the framework that have the potential to improve the balance of regulatory and investment risk compared to the current ex-post framework.

EnergyAustralia has therefore reconsidered its capex strategy in relation to the new ex-ante capex framework proposed by ACCC. The extended time frame has provided additional opportunity for planners to consider the transmission strategy in isolation to the distribution business, which has driven an awareness of the significant increase in replacement spending that is required within the transmission business to ensure it meets established asset age criteria. While asset condition is critical, asset age is still an important consideration for EnergyAustralia in terms of long term planning and network sustainability.

3.1.2 Reassessment of security standards

In recent months, the security standard for supply to areas within EnergyAustralia's franchise area has been under review. Recent events in Newcastle that involved concurrent outages at TransGrid's main supply point to Newcastle and on EnergyAustralia's subsidiary system came within moments of causing major wide-spread interruptions in the area. This event and the general pressure on supply into the Newcastle and Hunter region has prompted a reassessment of the security standards offered to areas outside the Sydney CBD.

In NSW, system security standards are set by the networks with reference to general industry standards. EnergyAustralia has until recently used a deterministic (N-1) criteria for most areas. However, for the Sydney region, a "modified (N-2)" criteria is used to ensure a higher level of redundancy is used in critical areas.

TransGrid and EnergyAustralia are currently discussing a change to the established planning standards. Ultimately however, EnergyAustralia believes this issue is one that requires government involvement to set minimum standards for various sectors of the community. This is currently being pursued with the NSW government.

3.1.3 Greater risks of under-forecasting capital requirements

EnergyAustralia recognises that the new capital framework contains greater risk associated with under forecasting capital spending than under the ex-post framework. Under an ex-post review there is an opportunity for a TNSP to defend non-forecast investments at the end of period review and assuming it can demonstrate prudence and efficiency, the regulator will recognise that investment.

Under the ACCC's firm ex-ante cap, regardless of the prudence or efficiency, any spending above the cap will not be recognised. No ex-post review will be applied and the TNSP will effectively receive zero return for its investment. As noted previous, EnergyAustralia does not believe that the Code allows the ACCC to "strand" efficient investment at the subsequent review, and we reserve our right to seek recognition of any higher expenditures, should they occur at the next reset.

In any case, EnergyAustralia has reviewed its capital program in light of the risk in the ex-ante framework as well as a joint independent/internal review of our requirements. This has led to a modest increase in the replacement capital program. The impact on the augmentation part of the program is negligible as most of the effected projects have been recommended for exclusion.

Table 1 (following page) summarises EnergyAustralia's revised capital program showing projects which are included under the proposed cap and which are excluded.

The proposed program is $255.7m plus an amount to cover the customer connections and the impact of variations to the scope of water treatment for the Haymarket cable tunnel. Of this total it is proposed that $146m will be covered by the ex-ante cap and approximately $109.7m (plus customer connections and the Haymarket Tunnel variations) be regarded as excluded projects.

The projects covered under the proposed ex-ante cap comprise

- Augmentation Projects $48.0m
- Replacement Projects $93.9m
- Compliance projects $ 4.1m
- Total under Ex-Ante Cap $146m[10]

The following section details projects included under the proposed cap.

[10] $2004 real adjusted

Table 1 - EnergyAustralia's revised capital program 2004-2009

ACCC CAPITAL SUBMISSION FOR 2004/05 - 2008/09

Adjusted $2004 Real

GROWTH

PROJECT	CAP	EXCLUDED	TOTAL
Cap			
132kV connections to Haymarket BSP & Campbell St	3.2	-	3.2
Installation of Beresfield STS	12.6	-	12.6
Transmission Boundary Metering	2.3	-	2.30
Kurri Distribution Connections	0.6	-	0.6
132kV network development in Newcastle Western Corridor	8.5	-	8.5
Gosford STS Capacitor Installation	0.6	-	0.6
Drummoyne Zn Constraint	4.2	-	4.2
Tomago STS Distribution Connections	1.4	-	1.4
Minor Augmentatio of Inner Metropolitan 132kV Network	4.9		4.9
West Gosford Zn Constraint	3.9	-	3.9
Macquarie Park Zn Constraint	3.8	-	3.8
Upgrade feeder 926	0.7	-	0.7
132kV network development in mid-southern Central Coast	0.8	-	0.8
Possible Kurri Harmonic Filter	0.6		0.6
Excluded			
Major Inner Metropolitan 132kV Network Development		35.6	35.6
Lower Hunter 132kV Network Development	-	11.6	11.6
Tunnel Arbitration	-	Confidential	Confidential
Unconfirmed Customer Connections	Indeterminate	Indeterminate	Indeterminate
TOTAL GROWTH	**48.0**	**47.3**	**95.3**

ACCC REPLACEMENT

PROJECT	CAP	EXCLUDED	TOTAL
Cap			
Installation Green Square Zn	19.0	0	19.0
Substation Equipment	26.0	0	26.0
Transformers	20.8	0	20.8
UG Mains	12.7	0	12.7
OH Mains	15.4	0	15.4
Relocation of 132kV Feeders 96A, 96B, 96U, 96W & 95L	0.0	0	0.0
Excluded			
Replace 132kV Feeder 908 / 909	0	36.7	36.7
Ourimbah STS Refurbishment	0	25.7	25.7
TOTAL REPLACEMENT	**93.9**	**62.4**	**156.3**

COMPLIANCE			
PROJECT	**CAP**	**EXCLUDED**	**TOTAL**
Cap			
Electronic Security	0.7	-	0.71
OIL PCB	1.0	-	1.00
Oil Contatinment	1.1	-	1.05
Internal Fire Doors	0.8	-	0.83
Fire Stopping	0.2	-	0.21
Water Crossing	0.2	-	0.16
Asbestos Removal	0.1	-	0.15
	4.1	**0.0**	4.1
TOTAL COMPLIANCE			**4.1**

TOTAL CAP	**146.0**
TOTAL EXCLUDED	**109.7**
TOTAL ACCC EXPENDITURE FOR 2004/05 - 2008/09 (Excluding Tunnel Arbitration)	**255.7**

3.2 AUGMENTATION PROGRAM

3.2.1 Projects Under Construction

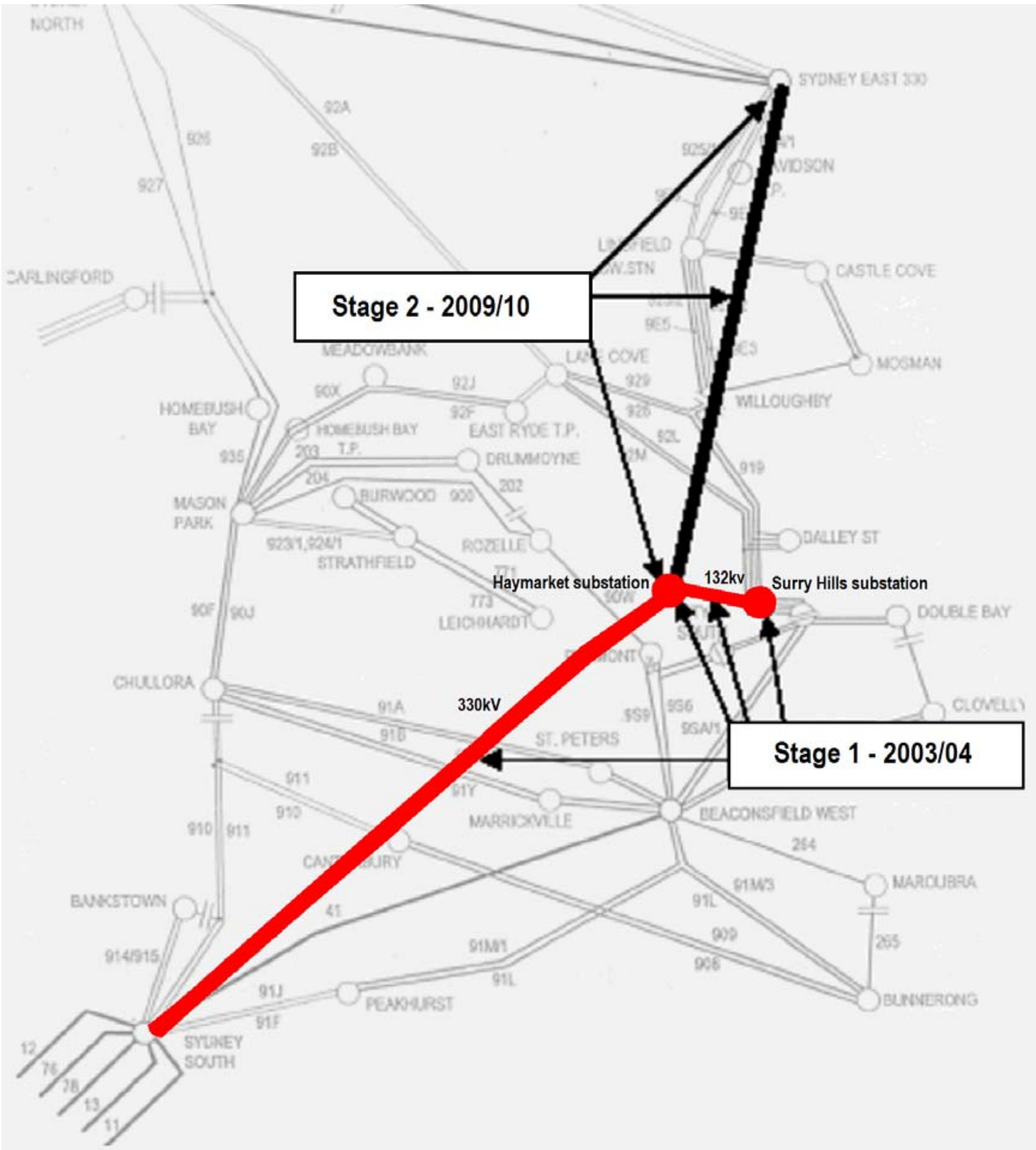
Project 1 - Haymarket & Campbell St Substation

EnergyAustralia, in conjunction with TransGrid is upgrading the transmission and distribution networks in the CBD and inner metropolitan areas of Sydney. The main driver for this upgrade is the expected load growth, which required system augmentations to meet the security standards required by Schedule 5.1 of the Code. The ACCC accepted the prudence of the entire amount of capital EnergyAustralia planned to spend over the 1999-04 regulatory period, which included the "Sydney Central connections".

EnergyAustralia and TransGrid prepared a joint regulatory test assessment of this upgrade. NERA was engaged to undertake this regulatory test in the first instance. In the initial assessments 14 options were analysed by NERA on the basis of information provided by TransGrid and EnergyAustralia. These included:

- 5 network options
- 2 generation options
- 7 bundled options (DSM, network and generation)

NERA concluded that "…options in which the 330kV Haymarket line is commissioned as the first stage of investment, in 2003/04, are the lowest cost, under each of the four scenarios considered". It further concluded that "…the lowest cost investment in the first stage is a network option (option 3)".



SKM (for EnergyAustralia), EnergyAustralia major projects (99/00-03/04) prudence assessment (March 2003)

The EnergyAustralia part of the CBD upgrade involves:

- New 132kV connection between the new Campbell Street zone substation and TransGrid's Haymarket 330/132kV substation at a cost of $53M
- 132/11kV zone substation in Surry Hills (Campbell Street).

Cost variations

CBD 132kV Cable Tunnel Project

The EnergyAustralia board approved $53M for the CBD 132kV Cable Tunnel Project. 50% of this amount is to be allocated to ACCC and 50% allocated to IPART due to the shared distribution and transmission assets in the cable tunnel.. At 30 June 2004, $43.15M had been spent on the project. By 30 June 2005 an additional $4M is expected to be spent of which $2m will be allocated to ACCC.[11]

A variation was necessary for treatment of water ingress and the solution and costs are yet to be finalised. EA are proposing that the cost of this element considered as an excluded project.

Campbell St Zone Substation

A payment of $1M is still required for purchase of the substation land and approximately $0.2M of substation works are expected to be spent by the end of the financial year.

Project Costs for 2004-2009 Period (ACCC portion only)

	2004/05	2005/06	2006/07	2007/08	2008/09	Total
Campbell St	$1.2m					$1.2m
CBD Tunnel	$1.9m	0.1m				$2m
Total	$3.1	0.1m				$3.2m

* Subject to the outcome of the water treatment solution additional expenditure could be added in either 2004/05 or 2005/06. EnergyAustralia consider these additional costs should be treated as an excluded project.

Project 2 - Installation of Beresfield Subtransmission Substation

Background

Beresfield 132/33kV Subtransmission Substation (STS) project is needed to meet increased demand attributable to residential and industrial growth. Neighbouring zone substations have experienced high growth rates in peak demand, particularly in summer, exceeding firm capacity for several hours per day.

Sub transmission feeders have also been overloaded and voltages have been depressed at some substations. The regional load is expected to be nearing or above total installed capacity by the 2004/05 summer.

EnergyAustralia carried out a planning investigation in 1999 and a value management study for the East Maitland/Tarro area in 2002, along with engineering investigations and preliminary community consultation.

The planning studies investigated the following three investment options:

1. Construct a new 132/33kV STS at Beresfield (between Kurri and Tomago STS) including associated distribution works.
2. Construct a 132/11kV zone at Thornton along with re-building existing East Maitland and Tarro Zones as 132/11kV zones.
3. Construct a 66/11kV zone at Thornton along with re-building existing East Maitland and Tarro Zones as 66/11kV zones with major capacity improvements at 66kV level at Kurri

11 A further $5.5m of expenditure in 2003/4 associated with payment to TransGrid for a joint cable tunnel from Haymarket to Wattle St was allocated 100% to ACCC

STS.

Investment options NPVs[12]

Augmentation Option	INITIAL 1999 NPC	2003 NPC Review	2004 NPC Review
1. 132/33kV @ Beresfield (preferred option)	$20.087M	$24.32M	$32.042M
2. 132/11kV @ Beresfield	$27.477M	$32.159M	$46.615M
3. 132/66kV @ Beresfield	$23.701M	$30.174M	$47.244M

The preferred option was the construction of a new 132/33kV STS located on Weakleys Drive, Beresfield because it was the least expensive strategy. The substation will be supplied from existing 132kV feeders 9NA and 96F. It will have an initial 120MVA firm capacity and provide 33kV supply to Tarro, East Maitland, Wallalong, Martin's Creek, Gresford and the future Thornton substation.

Beresfield STS is required to provide necessary load relief for Kurri and Tomago sub-transmission substations as well as address limitations on the 33kV network supplying the East Maitland and Tarro areas.

Beresfield STS is to also:

- provide a future point of supply for Taree for Country Energy;
- address capacity and voltage limitations in the 33kV distribution network supplying the East Maitland area.
- reduce real and reactive peak load losses
- provide interconnection capability and improved interconnection
- provide long-term supply development, increased security and improve future reliability for customers
- provide best use of existing system assets from both operational and financial perspective.

This project will increase the capability of EnergyAustralia's network, hence it is an augmentation.

EnergyAustralia's study did not yield viable demand management options capable of offering capital deferment, due to the magnitude of supply capacity shortfall and high growth.

The "Beresfield" project involves the construction of Beresfield subtransmission substation (an ACCC regulated transmission exit point) and extensive distribution works (IPART regulated assets).

Issues

The initial need for this project was identified in a 1999 planning investigation.

EnergyAustralia's board approved funding of $20.6m for the construction of Beresfield substation which is entirely ACCC regulated expenditure. Substantial expenditure occurred

[12] Review of Draft ACCC Determination re EnergyAustralia Transmission Projects – SKM 1st July 2004

prior to the start of the regulatory period. The remaining expenditure of $12.6m in expected to occur during the first year of the current regulatory period. SKM assessed the project to be a prudent investment.

Project Costs for 2004-2009 Period

Years	2004-05	2005-06	2006-07	2007-08	2008-09
Exp ($M)	12.6	0.0	0.0	0.0	0.0

The Beresfield STS is currently being built and is expected to be completed in 2005.

Project 3 - Transmission Metering

Need for Project

Physical losses occurring in EnergyAustralia's transmission assets are being purchased from the NEM by EnergyAustralia but do not appear to be reflected in the published loss factors. The published loss factors are the means by which a host retailer would normally recover the energy associated with such network losses from customers. These losses are being purchased at ETEF rates. For financial year 2003/04 EnergyAustralia Network have estimated these losses to be 112 GWh or 0.37% of all EnergyAustralia Network purchases.

EnergyAustralia are currently buying transmission losses from the pool for all customers within the EnergyAustralia network boundary. The primary mechanism for recovering these losses is uplifting the customer's meter reading by the published loss factors [DLF and TLF]. However we have confirmed that the published loss factors specifically do not account for these losses. Therefore we are not recovering them from customers or third party retailers.

This issue has occurred because of the process for classifying assets as either 'distribution' or 'transmission'. The determination of distribution and transmission loss factors is divorced from the process and responsibility of metering. The classification of assets and the calculation of DLFs is the role of EnergyAustralia Network as the Local Network Service Provider [LNSP], and the responsibility for TLF calculation rests with NEMMCO.

Proposed Works

The solution is to relocate the NEM settlement boundary from the EnergyAustralia/TransGrid boundary to the distribution/transmission boundary. This will require the installation of additional metering in both EnergyAustralia and TransGrid substations. Physical transmission losses are currently occurring downstream of EnergyAustralia's NEM settlement boundary metering. By relocating the NEM settlement boundary to the distribution/transmission boundary all transmission assets and their losses will then be upstream of the settlement boundary, thus any physical losses are confined to 'the pool' and will not be physically purchased by EnergyAustralia. Under this scenario EnergyAustralia will become indifferent to any discrepancies between physical transmission losses and TLFs.

Project Costs for 2004-2009 Period

EnergyAustralia's estimate for this project is:

2004/05	2005/06	2006/07	2007/08	2008/09	Total
$2.3m	-	-	-	-	**$2.3M**

* Costs consist of Enerserve and Metering costs (Accuracy + - 10%)

* No expenditure is forecast between 2005/6 – 2008/9.

* Any changes to transmission/distribution boundaries during the 2004/9 period could require additional metering expenditure.

Status

This project commenced in 2004 and is expected to be completed by June 2005.

Project 4 -Additional Distribution Connections from Kurri STS

The following works are being out carried at Kurri subtransmission substation to provide additional connections to the distribution system.

<u>Rutherford 33kV Feeder Bay</u>

This is an additional 33kV feeder bay needed for the 33kV feeder arrangement for Rutherford zone substation. This will provide feeder capacity for Rutherford and Telarah zone substations supplied from Kurri STS. The estimated total cost of this project is $0.38M. A total of $0.21M was spent in the previous regulatory period leaving $170k in 2004/5. Accuracy + - 10%.

<u>Kurri Split 33kV Feeder Bay</u>

The feeder bay is required to split the existing Cessnock and Kurri loads that are supplied from 33kV feeder 7 from Kurri STS. This rearrangement caters for future loading on Cessnock and the proposed Nulkaba zone substation. The existing 33kV feeder would be over loaded if the loads were not split onto two feeders. The estimated total cost of this project is $0.4M in 2004/5. Accuracy + - 10%.

Driver for Projects

Service standards are forecast to not meet minimum reliability requirements under single contingency outages, such that corrective network augmentation or non-network alternatives are required.

Project Costs for 2004-2009 Period

EnergyAustralia's estimates for the above mentioned projects are:

2004/05	2005/06	2006/07	2007/08	2008/09	Total
$0.6m	0.0	0.0	0.0	0.0	$0.6m

Estimate accuracy + - 10%

3.2.2 Anticipated projects

The following projects presently under development and are anticipated to start construction during the regulatory period. Whilst planning and economic studies associated with these projects are not yet complete EnergyAustralia consider that there is a high probability that these projects will proceed.

Project 5 - 132kV Development in Newcastle Western Corridor

Need for Project

The Newcastle Western corridor is continuing to be developed as the major growth area of Newcastle and Western Lake Macquarie. This region includes the suburbs of Edgeworth, West Wallsend, Elstelville, Holmesville and Cameron Park. Load is growing at approximately 5MVA per annum in this region. Construction and sales of 1300 lots within the North Lakes region have been progressing rapidly and an additional 2500 lots have been allocated for release. These lots are assumed to require an additional 15MVA of load. A new retail town centre is planned for the adjacent Elstelville and the light industrial subdivision at Cameron Park is 30% completed. 3MVA of additional load is expected for this development. Tasman Mine has advised they will take load prior to 2006 and expect to use 4MVA of load. Also the closure of Gretley Colliery could lead to the development of approximately 6km^2 of land in the region.

Three distribution system zone substations Cardiff, Edgeworth and Wallsend currently supply this area. Peak load growth is such that these substations have experienced peak load above their firm rating (for an N-1 planning criteria). Growth is expected to require three new sub-stations progressively over the next 5 years:

1. The first substation is to be constructed at Maryland by 2006. This project was committed in the 1999 – 2004 period. This will be a distribution asset.

2. The second substation is to be constructed at Argenton by 2007 due to loads on Wallsend, Cardiff and Edgeworth all exceeding their respective firm ratings. This will also be a distribution asset.

3. The third substation is to be constructed at West Wallsend around 2009. This is anticipated to be a transmission asset.

Table 2 - Zone Forecast Showing Impact of Committed and Anticipated Projects

Zone Substation	Rating MVA	2003	2004	2005	2006	2007	2008	2009
Argenton	50	0.0	0.0	0.0	0.0	24	27.49	29.16
Cardiff	22.9	28.94	32.39	34.17	36.06	22.05	21.27	22.46
Edgeworth	22.9	30.7	32.45	34.69	24.91	21.92	24.58	15.23
Maryland	37.5	0.0	0.0	0.0	17.66	22.89	24.49	24.21
Wallsend	27.1	33.95	30.6	33.57	29.08	27.25	29.3	27.5
West Wallsend	37.5	0.0	0.0	0.0	0.0	0.0	0.0	18

* Highlighted cells indicate that the substations are forecast to be loaded in excess of their respective firm ratings

Driver for Project

With out augmentation service standards are forecast to not meet minimum reliability requirements under single contingency outages, such that corrective network augmentation or non-network alternatives are required.

Possible Options for West Wallsend Zone Substation

The existing zone substations are already constructed to their maximum capacity and there is no scope to develop them further to cater for the expected new load in the region. There is no other augmentation option apart from the development of a new zone substation in the area.

Option 1

Construct a new 132kV zone substation at West Wallsend. 132kV feeder 9NA transverses the area and provides readily available substation supply. Estimated cost is $10.8M. (Costing based upon estimate for similar project at Maryland. Accuracy + - 20%)

Option 2

Construct a new 132kV zone substation at West Wallsend but delay the establishment of the substation by 2 years by installing additional 11kV feeders, connected to Maryland zone substation. $2.1M is the estimated cost of the 11kV feeder works. Accuracy + - 20%.

Option 3

Construct a new 33kV zone substation at West Wallsend. Would require the construction of 12km of overhead 33kV feeder. Estimated cost is $11.5M. (Costing based upon estimate for similar project at Nulkaba and Beresfield. Accuracy + - 20%)

Option 1 is EnergyAustralia's preferred option as it has the lowest net present cost and provides the best long term solution for meeting load growth on the zone and subtransmission networks in this area.

Status

A substation site is still to be selected although it is expected to be adjacent to 132kV feeder 9NA. Site assessments are being conducted, project designs and costs are yet to be finalised and detailed design and preliminary development for this project are yet to commence.

Project Costs for 2004-2009 Period

EnergyAustralia's estimate of expected cash flows[13] for the establishment of West Wallsend zone substation are.

2004/05	2005/06	2006/07	2007/08	2008/09	Total 2004-9
-	$0.1M	$0.8M	$2.7M	$4.9M	**$8.5M**

* (Option 1 budget estimate only and based upon estimates received for Maryland zone substation)
* An additional $2.7M is expected in 2009/10 to complete the project

Project 6 - Gosford Subtransmission Substation Capacitor Installation

Need for Project

System Loading

Loadflow analysis indicates that an outage of feeder 958 during times of peak winter load, will cause loading to reach capacity limits on Ourimbah STS 132kV busbar from 2007 and feeder 95C from 2009. Loadflow highlights the constraints on the mid-southern Central Coast 132kV network. The diversified subtransmission forecast 2004 was used to determine the timing of the network constraints.

System Power Factor

The National Electricity Code (NEC) Sc 5.3.5 requires power factor of better than 0.95 for 132kV networks connected to transmission systems. The average power factor of the Central Coast 132kV system is also below the required level. Despite the expenditure of almost $2m on 32 MVAr of 11kV capacitors in 2002 and 2003 the expected average power factor of 132kV load on the Central Coast in 2005 is expected to be 0.86. A further 92MVAr of power factor correction is required to achieve NEC requirements. EnergyAustralia distribution are presently in the process of implementing a demand management option to improve customer power factors in the Central Coast which is expected to provide about 10MVAr of savings. Proposed distribution system projects will provide a further 25MVAr.The installation of an additional 36MVAr of 66kV capacitors at Gosford would provide 70% of the remaining deficit in reactive support. It is anticipated that the balance of the deficit will be provided by either additional 66kV capacitors at Gosford or by more distribution system capacitors.

[13] Real $2004

Driver for Project

Without this project, service standards are forecast to not meet minimum reliability requirements under single contingency outages, such that corrective network augmentation or non-network alternatives are required.

Compliance with the system power factor requirements of the NEC.

Possible Options

As EnergyAustralia has already installed 11kV capacitors in zone substation with low power factor and has embarked on a program of improving customer power factors there are no viable alternatives to more 66kV capacitors.

The following options address system loading issues:

<u>Option 1</u>

Installation of 36MVAr of additional 66kV capacitors at Gosford STS. This option will help defer future major expenditure by 1 year by reducing 132kV network loads. Estimate for this work is $0.6M. Accuracy + - 10%.

<u>Option 2</u>

Construction of another 132kV feeder between Tuggerah BSP and Ourimbah STS and the reconstruction and uprating of the Ourimbah STS. A new feeder between Tuggerah and Ourimbah would be approximately 9km long. A budget estimate for the feeder and substation works is $30M. Accuracy + - 25%. (SKM Consultants estimated that upgrading Ourimbah STS would cost $25M.)

<u>Option 3</u>

Conversion of Berkeley Vale zone substation to 132/11kV operation. This option will reduce the loading at Ourimbah STS and as a consequence reduce the loading on feeder 95C. A budget estimate for this work is $17M. Accuracy + - 25%. These works would be expected to become a new large distribution asset.

Option 1 is the preferred option. It is the lowest cost and the easiest to implement. Option 3 is expected to occur in the future to cater for constraints on Berkeley Vale zone substation and the associated 132kV network. The 132kV busbar at Ourimbah is expected to be replaced within the next 5 years.

Status

A detailed estimate has been completed and the project is expected to be completed this financial year.

Project Costs for 2004-2009 Period

EnergyAustralia's estimate for this project is:

2004/05	2005/06	2006/07	2007/08	2008/09	Total
$0.6M	-	-	-	-	**$0.6M**

Project 7 - Drummoyne Zone Substation Constraint

Need for Project

Peak demand at the Drummoyne zone substation is expected to reach firm capacity over the next few years and the adjoining substations have insufficient capacity to address the loads at Drummoyne.

Type of Augmentation

A new small network asset is to be constructed. The proposed works are defined as a reliability augmentation under the National Electricity Code.

Driver for Project

Without this project, service standards are forecast to not meet minimum reliability requirements under single contingency outages, such that corrective network augmentation or non-network alternatives are required.

Possible Options

<u>Option 1</u>

Extend the existing 11kV switchboard and install a 3rd transformer. The substation was originally designed to be a three transformer zone substation. Cost = $4.0M (Budget estimate only + - 20% accuracy).

<u>Option 2</u>

Install another zone substation in the area to cater for the expected load growth. Cost = $20M (Budget estimate only + - 25% accuracy) Based upon the expected costs for the installation of Green Square zone substation.

Option 1 is expected to be selected as it is the least cost option. Initial substation design allowed for an additional transformer to be ultimately installed.

Project Costs for 2004-2009 Period

EnergyAustralia's estimate of expected cash flows[14] for this project are:

2004/05	2005/06	2006/07	2007/08	2008/09	Total
$0.0M	$0.8M	$2.7M	$0.6M	-	**$4.2M**

* Costs based on Option 1.

Project 8 – Additional Distribution Connections from Tomago STS

Projects

The following works are to be carried out at Tomago subtransmission substation to provide additional connections to the distribution system.

Nelson Bay 33kV Feeder Bay

A new 33kV feeder is presently under construction between Tomago STS and Nelson Bay zone substation. This feeder is to be constructed at 132kV but is to be initially operated at 33kV. A new 33kV feeder bay is to be installed at Tomago STS in 2004/5 to provide this arrangement.

Nelson Bay 132kV Feeder Bays

Two new 132kV feeder bays are to be constructed at Tomago STS and two 132kV feeders are to be installed between Tomago and Nelson Bay in order to convert Nelson Bay to a 132/11kV zone substation. One of the feeders will be initially operated at 33kV.

Driver for Projects

Without this project, service standards are forecast to not meet minimum reliability requirements under single contingency outages, such that corrective network augmentation or non-network alternatives are required.

Project Costs

EnergyAustralia's estimate of expected cash flows[15] for this project are:

:2004/05	2005/06	2006/07	2007/08	2008/09	Total 2004-09
$0.4M	0.0	0.0	$0.4M	$0.6M	$1.4M

* Estimate accuracy + - 25%

[14] Real $2004
[15] Real $2004

Project 9 - Minor Augmentation of Inner Metropolitan 132kV Network

Need for Project

Both TransGrid (refer to NSW Annual Planning Report 2004) and EnergyAustralia have identified that within the next 5 years, action will need to be taken to address network constraints on the inner metropolitan and southern Sydney 330kV and 132kV networks. Failure of either the Sydney South – Beaconsfield West or Sydney South – Haymarket 330kV cables and any of approximately 30 other critical circuits or transformers may result in the rating of some remaining elements being exceeded. EnergyAustralia's System Reliability Planning Standards state that "because there are a large number of critical elements within the system it has been decided to expand the security used in planning the supply to the CBD and inner suburbs to be more in line with international practice by considering a simultaneous outage of cable 41 and any 132kV feeder or 330/132kV transformer and outage of any section of 132kV busbar"[16].

Constraints

Within the next 5 years, 330kV feeders 41 & 42, 132kV feeders 910/1 & 911/1 and TransGrid's Sydney South transformers No. 1, 2, 4, 5 & 6 will be overloaded during a number of single or double contingency outages. Feeder 41 is forecast to be constrained from 2005, feeder 42 from 2008, feeders 910/1 & 911/1 in 2010 and the Sydney South transformers in 2009.

Driver for Project

Without this project, service standards are forecast to not meet minimum reliability requirements under single contingency outages, such that corrective network augmentation or non-network alternatives are required.

Possible Options

Joint planning with TransGrid is required to determine how the above mentioned constraints will be addressed. The following options have been identified:

- Tuning of Load flows and Reinforcement of EnergyAustralia's 132kV network;

  Options to reinforce the 132kV network include the installation of phase shifting transformers to control power flows, installation of additional 132kV cabling and changing series reactors throughout the network
- Establishment of an additional 330/132kV substation and associated 330kV supply;
- Local generation;
- Demand management.

At this stage, EnergyAustralia's strategy is to implement low cost measures to optimise power flows in the beginning of the regulatory period which will defer major expenditure until later in the period. The following minor works are proposed:

- Replace series reactors (lower impedance reactors) in 91L & 91M/1 - $1.6M in 2005/6

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[16] EnergyAustralia's Network Management System Procedure, Document No.SE-T001, Page 2

- Replace series reactors (lower impedance reactors) in feeder 910 and 9111 - $1.6M in 2006/07

In addition to the above works EnergyAustralia is required to replace 3 x aging 50MVAr shunt reactors. These units are used to control voltages on the 132kV system during times of light load. It proposes to purchase 2 x 100MVAr shunt reactors for this purpose. The cost of installing 1 x 100MVAr unit to replace 2 existing reactors is included in the budget for replacement. As the second new shunt reactor will provide an increase in capacity the costs associated with this work have been included as an augmentation. The proposed works comprise

- Replace aged shunt reactor (1 x 50MVAr units with 1 x100MVAr units) at Chullora - $1.6M in 2005/06

Project Costs

EnergyAustralia's estimate of expected cash flows[17] for this project are:

2004/05	2005/06	2006/07	2007/08	2008/09	Total 2004-09
-	$2.9M	$1.7M	$0.4M	-	$4.9M

The medium term measures proposed include the installation of quadrature regulators and the establishment of a new 330/132kV supply point. As the amount of expenditure involved in this work is substantial and there is considerable uncertainty over the level of expenditure required, these major works should be regarded as excluded projects.

3.2.3 Possible projects

The following projects have been identified as being likely to proceed during the next regulatory period. There is some uncertainty over the timing of these projects.

Project 10 - West Gosford Zone Constraint

Need for Project

Loading on most of the substations that adjoin West Gosford are expected to reach firm capacity within the next few years and there is no scope to upgrade these substations. It is expected that load will need to be transferred to West Gosford in order to address the overloading on the adjoining substations. This will lead to the need to upgrade West Gosford Zone Substation itself within the next 5 years.

Driver for Project

Without this project, service standards are forecast to not meet minimum reliability requirements under single contingency outages, such that corrective network augmentation or non-network alternatives are required.

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[17] Real $2004

Possible Options

Option 1

Extend the existing 11kV switchboard and install a 3rd transformer. The substation is designed to be a three transformer zone substation. Cost = $3.9M (Budget estimate only + - 20% accuracy – based upon similar works at Sefton zone substation.)

Option 2

Install another zone substation in the area to cater for the expected load growth. Cost = $17M (Budget estimate only + - 25% accuracy. Based upon expected costs for the installation of Green Square zone substation.)

Option 3

Install 2 x 11kV feeders from Somersby zone substation so that 8.5MVA can be transferred away from West Gosford zone substation. This option would provide short term load relief at West Gosford. Cost = $2.5M (Budget estimate only + - 25% accuracy)

Economic analysis indicates that Option 1 is the least cost option and is thus expected to be selected. It has always been planned that once loading reached the firm capacity of the substation that an additional transformer would be installed.

Status

The project is at the identification of needs stage.

Project Costs for 2004-2009 Period

EnergyAustralia's estimate of expected cash flows[18] for this project are:

2004/05	2005/06	2006/07	2007/08	2008/09	Total 2004-09
-	-	$0.16M	$1.26M	$2.46M	**$3.9M**

Project 11 - Macquarie Park Zone Constraint

Need for Project

The substations that adjoin Macquarie Park are expected to reach firm capacity within the next few years and there is no scope to upgrade these neighbouring substations. It is expected that load will need to be transferred to Macquarie Park in order to address the overloading on the adjoining substations. This could lead to the need to upgrade Macquarie Park Zone Substation.

[18] Real $2004

Driver for Project

Without this project, service standards are forecast to not meet minimum reliability requirements under single contingency outages, such that corrective network augmentation or non-network alternatives are required.

Possible Options

Option 1

Extend the existing 11kV switchboard and install a 3rd transformer. (Switchboard extension and additional transformer estimate was based upon estimate for similar works at Sefton zone substation). Upgrade the 132kV protection and fibre optic communications (The protection system upgrade is estimated to be $0.6M and the fibre optic installation $1.0M – based upon estimate for OPGW installation on feeder 916/917). The substation is designed to be a three transformer zone substation. Total Project Cost = $5.6M (Budget estimate only + - 25% accuracy)

Option 2

Install another zone substation in the area to cater for the expected load growth. Cost = $17M (Budget estimate only - 25% to + 50% accuracy)

Option 1 is expected to be selected as it is the least cost option. It has always been planned that once loading reached the firm capacity of the substation that an additional transformer would be installed.

Status

The project is at the identification of needs stage. Given the high cost of alternative options it is considered likely that this project will proceed.

Project Costs for 2004-2009 Period

EnergyAustralia's estimate of expected cash flows[19] for this project are.

2004/05	2005/06	2006/07	2007/08	2008/09	Total 2004-09
-	-	$0.1M	$1.1M	$2.6M	**$3.8M**

[19] Real $2004

Project 12 - Upgrade Feeder 926[20]

Need for Project

Significant load growth is predicted on Berowra, Pennant Hills and Hornsby Zone Substations, with a large amount of residential development in the area. The respective summer growth rates are 6.6%, 4.1% and 4.8%. Continued residential development is anticipated in the Galston/Dural/Glenhaven area. This load is presently supplied from Hornsby and Pennant Hills..Peak loads occur in summer and summer loads are driving network augmentation. Pennant Hills was upgraded within the last few years and is not expected to exceed capacity until summer 2010/11. Hornsby is to be upgraded within the next couple of years, and is then expected to have sufficient capacity until 2013/14. Berowra is expected to have sufficient capacity until 2015/16. The 132kV feeder network (132kV feeder length = 23.9km) that supplies these three substations is expected to be constrained during a feeder outage at times of peak summer load by 2009.

Table 3 - Combined Berowra, Pennant Hills and Hornsby Zone Substation Loads

Feeder Rating (MVA)	Feeder Bay Rating (MVA)	2004	2005	2006	2007	2008	2009	2010	2011
239	220	178.2	186.6	196.1	205.3	215.0	225.2	235.8	247.0

* Forecast based upon 2004 and prior year loads
* Highlighted cells indicate that the feeder or feeder bay equipment is forecast to be loaded in excess of their firm ratings

Driver for Project

Without this project, service standards are forecast to not meet minimum reliability requirements under single contingency outages, such that corrective network augmentation or non-network alternatives are required.

Possible Options

Option 1

The most likely option will involve reconductoring feeder 926 along the existing towerline and utilising one side of the tower for a new 132kV feeder to connect to Pennant Hills. This may involve the use of low sag conductors to minimise the need to replace the current tower structures. The new feeder would be classed as a new small distribution asset. The reconductoring of feeder 926 would be a new small transmission asset. Approximately 11.5km of feeder 926 would be reconductored. The approximate cost of the overhead reconductoring would be $2.0M (based upon budget estimates for reconductoring similar 132kV with low sag conductor)

The new feeder connection to Pennant Hills would be considered a distribution asset. The underground section would be approximately 1km long and would be expected to cost

[20] This project was not included in EnergyAustralia's Annual Transmission Planning Report 2004 as the ramification for the transmission network has only recently been identified.

approximately $2.5M. (Based upon unit rates detailed in the SKM report "ODRC Valuation of Transmission Assets" – June 2004. Accuracy + - 25%.)

Note: Reconstructing the 11.5km section of feeder 926 with conventional type conductor would require complete reconstruction of the tower line, including replacement of many towers. This is not feasible at present levels of system loading. Significant community opposition to tower line reconstruction would be expected.

Option 2

Installation of another 132kV feeder between Sydney North and Pennant Hills. This distribution feeder would be approximately 12km long and would consist of overhead and underground feeder sections. For budget estimates only, it was assumed that the overhead construction would be 9km and the underground section 3km. The work is estimated to cost $15.2M (Accuracy + - 25%.)

Status

The project is at the identification of needs stage.

Project Costs for 2004-2009 Period

EnergyAustralia's estimate of the most likely cash flows for this project is

2004/05	2005/06	2006/07	2007/08	2008/09	Total 2004-9
-	-	$0.03M	$0.23M	$0.41	**$0.66M**

* The above costs are for community consultation only. No construction works are expected prior to the end of the regulatory period.

* (Accuracy + - 25%.)

Project 13 - 132kV Network Development in Mid-Southern Central Coast

Need for Project

Loadflow analysis has highlighted that under certain 132kV feeder outages, some of the 132kV feeders that transverse the mid and southern Central Coast region are expected to be constrained over the next 5-10 years. If it is assumed the capacitor installation proposed in Project 6 proceeds, the worst case scenario is the loss of feeder 958 at times of peak system loads. Under this scenario Ourimbah 132kV busbar is expected to be overloaded from 2008 and feeder 95C is expected to be overloaded from winter 2010. The issues at Ourimbah are expected to be addressed by replacement of the Ourimbah busbar as part of the Ourimbah replacement project. Feeder 95C is 8.6km long and consists of 54/3.25 ACSR/GZ 3OH(V) type conductor, designed to operate at 100°C and is constructed on a timber pole.

Driver for Project

Without this project, service standards are forecast to not meet minimum reliability requirements under single contingency outages, such that corrective network augmentation or non-network alternatives are required.

Possible Options

Option 1

Convert Berkeley Vale zone substation to 132/11kV operation. The main reason for selecting this option is the loading on Berkeley Vale 33/11kV zone substation and the associated benefits of addressing the 132kV network constraints (feeder 95C and the 132kV busbar at Ourimbah STS). This option addresses a number of network constraints including the 33kV feeder network that supplies Berkeley Vale, 11kV switchgear and zone transformers. This would help defer future major capital expenditure by 2-3 years on the Central Coast 132kV network. It seems likely that Berkeley Vale 132kV substation will be connected to distribution feeders and will be considered as a distribution asset. The budget for conversion of Berkeley Vale to 132kV operation has thus been included in the IPART determination. There is a possibility that Berkeley Vale may be connected to transmission mains, which would result in it being a transmission asset. If this occurs it has been agreed that it would constructed as a distribution asset and transferred to the transmission RAB at the conclusion of the current regulatory period. The costs associated with the conversion of Berkeley Vale is $17M (estimate + - 20% accuracy).

Should Berkeley Vale proceed the proposed new 132kV feeder would be required in about 2012. To achieve this completion date community consultation, line design and environmental approval would be required during this regulatory period.

Option 2

Install a 2nd feeder between Gosford subtransmission substation and Tuggerah BSP. The approximate length of this feeder would be 18.5km. If the feeder was constructed as a single circuit concrete pole line then the approximate cost would be $14.5m Accuracy + - 20%). There is a strong possibility that urban portions of this feeder may need to be installed underground. This is would increase the cost by $10m assuming 5km of UG construction.

Project Costs for 2004-2009 Period (include in Cap)

It is likely that Berkeley Vale will be converted to 132/11kV operation by 2007/08 and EnergyAustralia's submission is based on this assumption.

EnergyAustralia's estimate of expected cash flows[21] for this project are:

2004/05	2005/06	2006/07	2007/08	2008/09	Total 2004-9
-	-	$0.01	$0.14	$0.61	**$0.8M**

[21] Real $2004

The above costs are for community consultation and initial line design only. Accuracy + - 25%. No construction works are expected prior to the end of the regulatory period.

Due to the uncertainty over the extent of the required line route or the extent of undergrounding required it is not possible to provide an accurate indication of the complete costs of this project.

Project 14 - Possible Kurri harmonic filter

Kurri 132kV Harmonic Filter

Ongoing harmonic problems on feeder 953 have been highlighted with recent problems experienced with interference to Telstra and for Redbank PS and Rothbury Zone. Analysis indicates that the network is amplifying low level source harmonics from the Kurri Aluminium Smelter. Effects have been temporarily addressed through switching re-arrangements. A Harmonic Filter is proposed to be installed to rectify the harmonic problems. This filter is yet to be specified and costs associated with its acquisition and purchase are uncertain.

Project Costs for 2004-2009 Period

EnergyAustralia's estimate of the most likely cash flows for this project is:

2004/05	2005/06	2006/07	2007/08	2008/09	Total
0.0	0.0	$0.1M	$0.4M	$0.1M	$0.6M

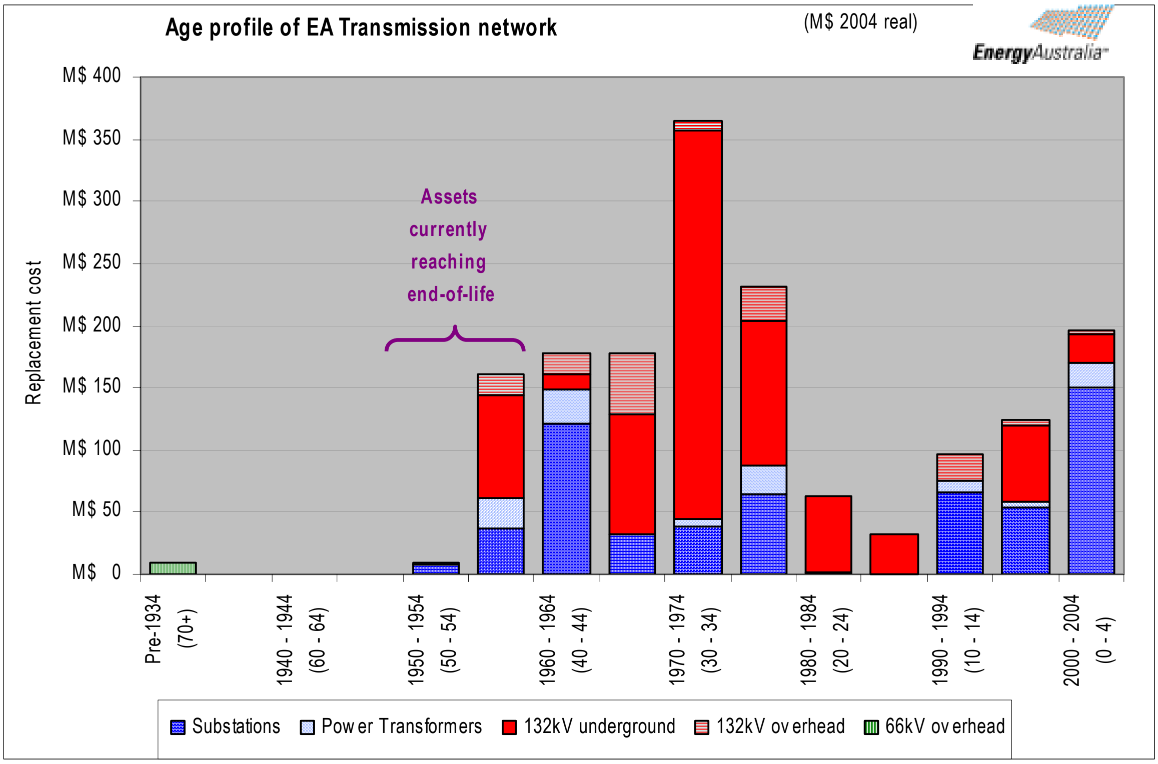
(Accuracy + - 25%.)

3.3 REPLACEMENT

EnergyAustralia's Network Business sets its replacement strategies to provide a safe, reliable, technically and economically sustainable electrical supply network.

The average age of EnergyAustralia's transmission system is 27 years, making it one of the oldest networks in Australia. EnergyAustralia's equipment age profile is non-uniform (see Figure 3). Most of the EnergyAustralia's transmission assets were constructed in the 1960s and 1970's and will reaching the end of the service lives between now and 2020.

Figure 3 - Age profile of EnergyAustralia's transmission network



The age profile of EnergyAustralia's system requires planning of replacement to be based on two major needs:

- Strategic requirements - To ensure an overall sustainable age and condition profile over time.
- Condition based requirements – To ensure that assets which are aged or are poorly performing are identified and replaced.

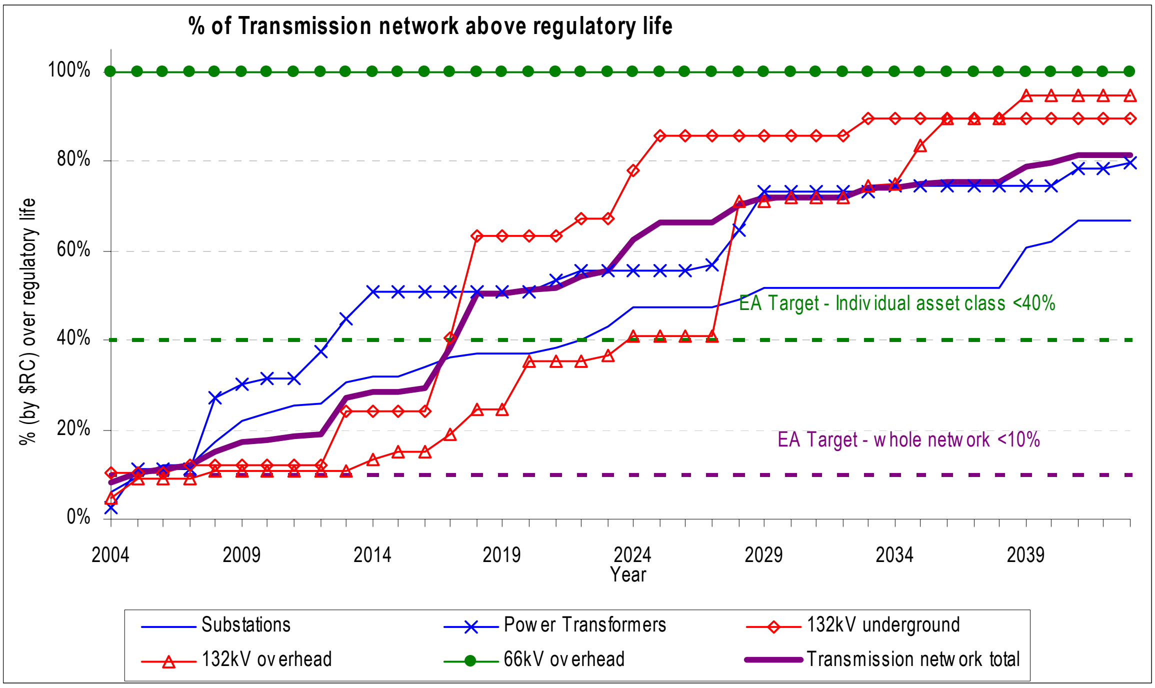
The overall replacement program is a coordinated blend of the above needs which is targeted to ensure both that life cycle costs, including both capital and operating expenditure, are minimised.

3.3.1 Strategic Requirements

The non-uniform age profile of EnergyAustralia transmission assets and the large number of assets approaching end of life make it necessary for EnergyAustralia to adopt a significant replacement program to ensure that the level of replacement expenditure is balanced and kept at sustainable levels.

As shown in Figure 4 without a significant replacement program EnergyAustralia's network will rapidly reach a point where significant proportions of the network are beyond their expected service life (the standard regulatory life).

Figure 4 - Percentage of Transmission network above regulatory life



EnergyAustralia has strategic guidelines to ensure that its system age and condition remained within sustainable limits and that lifecycle costs were minimised. To achieve these ends EnergyAustralia has previously adopted policy guidelines for its overall system (transmission & distribution) which require

(a) no more than 10% of the total asset base (in dollar terms) should exceed the standard asset life;

(b) no more than 40% (in dollar terms) of a single category of assets should exceed the standard asset life,

To confirm this approach EnergyAustralia commissioned SKM to review EnergyAustralia's transmission asset replacement requirements.

SKM endorsed EnergyAustralia's current practice of using standard lives for equipment with discretion for the performance and condition criteria to be paramount. Condition rather than age is the criteria used to prioritise replacement. Therefore a proportion of equipment will be replaced early if condition failures occur, and a proportion will exceed this standard life.

In view of the SKM findings EA are intending to retain the policy guidelines for its transmission system which require

(a) no more than 10% of the total asset base (in dollar terms) should exceed the standard asset life;

EnergyAustralia believes while the 40% limit for a single class of assets is still appropriate for its distribution system, it considers that a 40% limit is inappropriate for transmission assets. The distribution assets which are presently above the 10% limit comprise equipment such as

- solid dielectric underground cables
- OH distribution lines

Given the importance and complexity of its transmission assets EnergyAustralia consider it appropriate to apply a 10% limit to all asset classes for its transmission system.

Whilst the above strategic guidelines are necessary to provide an indication of the overall long term needs they cannot provide the detailed information necessary to develop a specific program of replacement works.

3.3.2 Asset Categories

For the purposes of managing the replacement program EnergyAustralia's assets have been divided into primary Network Asset Groups following the sub-category definitions outlined in the NSW Treasury Asset Valuation Guidelines. These groupings enable high level analysis of the impact of various capital and maintenance activities on the asset age profiles as well as providing a link to demonstrate opex and capex trade-offs to EnergyAustralia management and the various industry regulators. The asset groups relevant to the transmission business are as follows[22]:

> ***Zone Substations (ZN)*** - covers equipment and building refurbishment and replacement for substations with primary and secondary voltages of 132/11kV.
>
> ***Transmission Substations (TS)*** - covers equipment and building refurbishment and replacement for switching stations and substations with primary and secondary voltages of 132/66kV and 132/33kV.
>
> ***Transmission Overhead Mains (TMOH)*** - covers overhead lines of voltage levels 132kV, 66kV. The transmission OH lines include the mains conductors, their supporting poles & landing structures and associated pole mounted equipment.
>
> ***Transmission Underground Mains (TMUG)*** - covers underground cables of voltage levels 132kV. Underground cables include terminations, joints, link boxes, gas & oil charging points.

All identified replacement projects and programs are categorised into asset groupings and sub-categorised into asset types. For example, the asset category of Transmission substations has programs for replacement of transformers and for different types of switchgear.

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[22] Note These categories differ from those used by SKM in their analysis. SKM have grouped zone and subtransmission substations and have separatety identified transformers

3.3.3 Condition based requirements

The replacement of assets must also be considered at the individual level. Inevitably there are individual assets or particular types of equipment on the system which require replacement due to their condition.

EnergyAustralia, wherever possible, establishes condition monitoring criteria for specific classes of assets. Assets are assessed in accordance to their known failure mode characteristics and replacement / refurbishment programs developed using the Failure Mode, Effects and Criticality Analysis (FMECA) methodology for that specific asset category or group.

The assessment of condition is carried out using various methodologies dependent on the asset type. For example, 132kV underground cables are assessed according to their history of failures. Transformers are assessed by both test results, general condition (oil leaks, corrosion etc) and analysis of condition of components such as bushings, tap-changer etc.

The condition assessment of individual assets or types of assets is used to identify the timing of required replacement work and hence to create a prioritised replacement program which indicates a time frame for asset replacement. In some cases because of factors such as a high risk of failure equipment may need to be replaced immediately. In other cases the equipment could be assessed of having a remaining life which may be 20 years or more.

As condition rather than age is the criteria used to prioritise replacement, the condition based replacement program will contain equipment of varying ages. However as the majority of equipment identified for replacement on a condition basis will be aged, the condition based replacement program will have a significant impact on the age profile of the system.

Whilst condition assessment and priortisation of replacement requirements will provide bottom up indication of needs, a literal application of such an approach has many problems

- A piecemeal approach to replacement may be inefficient if replacement of associated equipment is not co-ordinated eg the replacement of switchgear one year and the associated feeder a few years later.
- The replacement of all assets of a particular age may not be feasible, particularly where “brownfields” replacement is required. Replacement program for some types of equipment may span more than one regulatory period and
- Concentration on individual components of a system could also lead inefficient, short term expenditures resulting in higher long term costs which may be unstainable.

3.3.4 Proposed Replacement Program

EnergyAustralia’s overall replacement program is a coordinated blend of the strategic and condition based requirements.

In preparing its replacement program EnergyAustralia have carried out a condition-based assessment of its transmission equipment and prioritised requirements and assigned expected remaining lives to equipment. This assessment has been used to provide a bottom up program.

The impact of this bottom up program on the overall age profile of the system has then been assessed. In addition Energy Australia engaged SKM to undertake a strategic analysis and modelling of transmission asset ages and possible impacts on the proposed program.

EnergyAustralia has developed its proposed replacement program of $156M reflecting changed assumptions (which are listed below), actual condition and experience of performance of assets. Under the revised capital expenditure proposals, the percentage of assets that exceed standard lives declines to 4% in 2009. EnergyAustralia has been informed by SKM's model outcome overlaid with existing condition information to prioritise actions in the next regulatory period. EnergyAustralia has estimated that replacement capex required for the 2009-14 period will be significantly higher, depending upon actual condition and performance of assets at that time. This will ensure EnergyAustralia can maintain its strategy of using standard (regulatory) class lives for transmission equipment, with discretion to allow a proportion of different assets to exceed this life based on condition assessment. SKM believes that this strategy is good practice and "yields the lowest overall replacement cost in the long run."[23]

This will result in the proportion of aged assets increasing to 8% in 2014 and is demonstrated below. This is within EnergyAustralia's 10% limit.

The proportion of assets above standard lives by asset category is provided in Table 4.

Table 4 - Assets Above Standard Life Under Present Submission

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Substations	3%	3%	5%	5%	4%	7%	8%	7%	7%	5%	7%
Power Transformers	0%	2%	3%	2%	2%	9%	7%	7%	5%	3%	3%
132kV underground	10%	5%	0%	0%	0%	0%	0%	0%	0%	0%	10%
132kV overhead	0%	5%	9%	9%	9%	10%	7%	4%	4%	4%	3%
66kV overhead	100%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total	**7%**	**5%**	**3%**	**3%**	**3%**	**4%**	**4%**	**3%**	**3%**	**2%**	**8%**

Key Assumptions for replacement Program

There are a number of assumptions that account for the difference between SKM's recommendations, and Energy Australia's revised submission.

- SKM assumed the direct like for like replacement of Cable 908/909 at an estimated cost of $80M. Energy Australia has identified an alternate route for this cable at an estimated cost of $36M. This estimate is dependent upon the route being acceptable.
- SKM assumed that all replacement projects would require an allowance for work to be done as brownfield projects. Energy Australia has however determined that a number of these projects would be done as effectively greenfield projects where the additional allowance for working within an existing environment is not required.
- SKM the costed replacement of circuit breakers on the basis of replacing complete bays of equipment. In many instances where 132kV circuit breakers require replacement the bus bars and supports are in good condition and only the circuit breakers require replacement. This enables substantial savings over the SKM estimates for Chullora and Mason Park ($28m).

[23] Aged Asset Replacement Projection – a report for EnergyAustralia by SKM, Oct 2004, p21.

- Condition assessment of the Kurri 132kV circuit breakers indicates that they are in good condition and should not require replacement during this period. This enables a saving of approximately $10m.

Comparison of the replacement work proposed under this submission compared with the SKM model is shown below.

Table 5 - EnergyAustralia's Replacement Program

REPLACEMENT PROGRAMS

Substation	Asset type	Submission	SKM Model
Transformers and Shunt Reactors replaced due to age			
132kV Shunt Reactors			
Mason Park			
Chullora		2	
132kV transformers			
Rozelle	132/33kV 20/30MVA	2	2
Bunnerong North	132/33kV 60/120MVA	2	3
Canterbury	132/33kV 40/60MVA	4	4
Kurri 132/33/66 kV	132/33kV 40/60MVA	3	1
Marrickville	132/11kV 35/40/45MVA	1	1
Tomago	132/33kV 40/60MVA	1	1
Circuit Breakers replaced due to age			
33kV circuit breakers			
Rozelle			2
Canterbury		27	28
Peakhurst		3	
66kV circuit breakers			
Kurri 132/33/66 kV			1
132kV circuit breakers			
Chullora		12	14
Mason Park		7	20
Peakhurst		11	
Lane Cove		7	
Canterbury		1	
Kurri			10
Other			
Overhead transmission lines replaced due to age			
66kV wood pole lines			
860 – KURRI – Stroud		1	1
132kV wood pole lines			
95C – TUGGERAH BSP - Ourimbah STS			1
957/1 - 957 TEE - Ourimbah STS			1
957/3 - 957 TEE - Vales Point BSP			1
9NA – NEWCASTLE - Tomago			1
132kV Overhead tower lines replaced due to age			
911 TEE – Canterbury STS			1
Sydney South BSP No 4 TX - 911 Tee			1
132kV Underground cables replaced due to age			
Feeder 90W - Rozelle STSS - Pyrmont STS		1	1

EXCLUDED PROJECTS

Feeder 908/909 - Bunnerong - Canterbury	132kV Underground feeders	1	1
Ourimbah	33kV Circuit Breakers	17	15
	66kV Circuit breakers	2	4
	132kV Circuit breakers	5	4
	66/33/11kV 15MVA Transformers	2	
	132/33kV 40/60MVA Transformers	3	

3.3.4 Replacement projects under construction

Project 15 - Installation of Green Square Zone Substation

Background

Alexandria zone substation is 49 years old and is considered to be at the limit of its acceptable age for network equipment which and is currently aged to 120% of standard equipment life. EnergyAustralia has identified the need to replace Alexandria and its associated 33kV cables with a new substation known as Green Square. This new substation will form a connection point between Energy Australia's distribution and transmission networks.

Green Square zone substation is a 132/11kV zone substation and is currently being built. This was ratified by a 1999 EnergyAustralia (EA) value management study.

This work is driven by the need to:

- retire the existing infrastructure at Alexandria substation by 2006 which has reached the end of its service life
- provide capacity to allow the loading at Mascot zone to be reduced in 2007 to facilitate its reconstruction
- provide capacity to meet long term growth in the South Sydney area.

The additional capacity provided by Green Square substation will be utilised in the long term to reduce loading on Mascot and Zetland substations, enabling them to supply full load during first contingency outages in accordance with Schedule 5.1 of the Code. Whilst the project will provide capacity for future load growth, project timing is driven by the need to replace ageing distribution infrastructure.

An alternative to establishing Green square substation was to rebuild or replace the existing Alexandria zone substation with a 33/11kV zone. The work was to include the installation of over 30km of 33kV cable to replace existing 33kV cables linking Alexandria to Bunnerong sub-transmission substation. The renewal of 33kV construction in an area of such high load density is not a cost-effective alternative to 132kV construction.

Type of Augmentation

This is a replacement project. However, it does provide additional capacity as the new asset is replacing a distribution asset. Work on this project commenced prior to the present Regulatory period. At the end of 2003/04, expenditure on ACCC regulated assets amounted to $2.6M.

EnergyAustralia's previous submission indicated an over ACCC spend for this project of $24.4m, with $21.4m being for the initial construction of Green Sq and $3m being for a subsequent augmentation. The subsequent augmentation is no longer required during the current period.

Project delays have resulted in movement of expenditure from the previous determination period to the present period. Details of revised expenditure is indicated below.

Project Costs

Projected costs associated with construction of Green Square

Years	1999-04	2004-05	2005-06	2006-07	2007-08	2008-09	TOTAL
Previous Submission	$4.2M	$11.3M	$5.9M	$0.6M	$2.0M	$0.4M	$24.4M
Present Submission	$2.5M	$11.8M	$7.2M	$0.0	$0.0	$0.0	$21.5M

3.3.5 Replacement Programs

Much of the rest of the proposed expenditure relates to replacement program for different types of transmission assets. In most cases the programs are subsets of the asset classes

Program 16 - Substation Replacement

This proposed program of $26M covers the replacement of substation assets (excluding power transformers).

The program contains 2 elements:

- An allowance of $2.1m to cater for the reactive replacement of equipment arising from breakdown[24]
- A proactive replacement program of $23.9m to cater for the replacement of equipment which has reached the end of its service life.

The proactive program primarily focuses on the replacement of aging circuit breakers, however provision has been included for replacement of two substation roofs which are in need of replacement.

Key objectives of the programs are:

- Replacement of substation roofs at Lane Cove and Canterbury.
- Replacement of six 33kV capacitor OCBs
- Replacement of twenty four 33kV OCBs at Canterbury substation
- Replacement of eleven 132kV CBs at various locations

Equipment in the program was identified on the basis of condition via a risk assessment by Manager-Operations investment.

Program 17 - Transformer Replacement

This proposed program of $20.8m covers the replacement of power transformers and shunt reactors.

[24] Derived from table 10 of SKM report Aged Asset Replacement Projections

The program contains 2 elements

- An allowance of $1.5m to cater for the reactive replacement of equipment arising from breakdown[25]
- A proactive replacement program of $19.3m to cater for the replacement of equipment which has reached the end of its service life.

Key objectives of the programs are replacement of

- Two 50 MVAr shunt reactors
- Two 120MVA 132/33kV transformers
- Eight 60MVA 132/33kV transformers
- Two 30MVA 132/33kV transformers
- One 37 MVA 132/11kV transformer.

Equipment in the program was identified on the basis of condition via a risk assessment by Manager-Operations investment.

Program 18 – Transmission UG Mains Replacement

- This program of $12.7 covers the replacement and refurbishment of UG transmission mains. Proposed work in this program includes
- Replacement of the oil filled sections of feeder 90W. ($8.5m)
- Planning for replacement of 91A & 91B next regulatory period. ($0.5m)
- Refurbishment of various UG circuits including 92FA ($3.7m)

Feeder 90W

Feeder 90W runs between Pyrmont and Rozelle. Much of the feeder comprises new XLPE cables, however critical sections of the feeder including submarine crossings of Rozelle bay is comprised of lead sheathed oil filled cable installed in 1962. As this cable runs through or adjacent to Sydney Harbour there is a significant potential pollution risk to the harbour in the event of oil leaks. Whilst 90W has had a good performance with respect to oil leaks, significant oil leaks have occurred recently on cables circuits of an identical age and type.

There are also presently issues with the size of the lead cable sheath which is of inadequate csa to cope with present system fault levels. Operational restrictions are required to manage this fault rating issue.

Planning for the Replacement of 91A & 91B

Feeders 91A and 91B are oil filled cables running between Chullora and Beaconsfield. These cables were installed in 1968 in a double circuit trench and are each more than 16km in length. A number of failures of these circuits has occurred in the recent past. It is anticipated that EnergyAustralia will replace these cables during the next regulatory period at an estimated cost

[25] Derived from table 10 of SKM report Aged Asset Replacement Projections

of $60-$100m. An amount of $500k will be required during the current period to carry out option studies and commence design and specification work for this project.

Refurbishment of UG Circuits

EnergyAustralia has an objective to reduce oil leaks from oil filled cables and has made commitments to the EPA on this issue. Whilst the long term solution to leaking cables is the replacement of oil filled cables with solid dielectric cables, this replacement program will take decades to complete. One of the most effective ways of controlling leaks is to identify cables which are vulnerable to leaks and to institute a program of refurbishing oil connections and rewiping joints.

EnergyAustralia commenced a program to address persistent oil leaks on feeder 92FA and 92FB in 2004. Stage 1 of the 92FA program involved refurbishment of 5 joint bays at an estimated cost of $370k. A further 15 joint bays on these feeders require refurbishment before the end of the Regulatory period. Total cost of work on 92FA and 92FB is estimated to be $1.5m.

EnergyAustralia also intend to carry out similar refurbishment work on selected joint bays on circuits 91L , 91M, 92J & 90X at an estimated further cost of $2.2m

Replacement Program 19 - OH Mains Replacement

This program of $15.4M covers the replacement and refurbishment of OH transmission mains. Proposed work in this program includes

- Selected refurbishment of sections of feeder 860 ($13.6m)
- Replacement of Jointed poles on 9NA/ 96F ($0.6m)
- Portable tower emergency structures ($0.4m)

Feeder 860

This line was constructed in 1930 and is approximately 90km in length It is proposed to replace most of the line at an estimated cost of $150k/km.

Replacement of Jointed pole structures

Feeders 9NA and 96F share common structures comprising jointed poles for part of their route. It is proposed to replace 20 structures at an average cost of $30k

Portable Tower Emergency structures

EnergyAustralia propose to purchase some portable emergency structures to provide a means of speedy recoverer in the event of a 132kV tower failure.

3.3.6 Anticipated Projects

The following projects presently under development and are anticipated to start construction during the regulatory period. Whilst planning and economic studies associated with these projects are not yet complete EnergyAustralia consider that there is a high probability that these projects will proceed.

Project 20 - Relocation of Feeder 96A, 96B, 96U, 96W and 95L[26]

Need for Project

The RTA is proposing to extend the F3 roadway from Seahampton to Branxton. The extension of the F3 will require feeders 96A, 96B, 96U, 96W and 95L to be relocated in the vicinity of Kurri and Buchanan. The length of feeders to be relocated is unknown at this stage as the road design has not yet been completed.

Driver for Project

Relocation/replacement of feeders due to the extension of the F3 freeway.

Project Costs

EnergyAustralia is unable to determine what this project will cost. EnergyAustralia expect that these works will be funded by the RTA. Detailed estimates and RTA confirmation of this project needs to be completed before project costs can be confirmed. The timing of the project is dependant on Federal Government Funding and the final RTA design is not yet completed. Discussions to date have included several options with between 1-8km of feeder route lengths requiring relocation.

The feeders being relocated impact on proposed excluded Project X4, the Lower Hunter 132kV Network Development. Should EnergyAustralia incur any substantial costs associated with this the line relocation it is proposed that recognition for expenditure will sought in conjunction with the Lower Hunter 132kV network development.

3.4 COMPLIANCE

Compliance Projects comprise projects which are required to upgrade existing infrastructure to meet Regulatory requirements or to achieve EnergyAustralia's duty of care requirements. EnergyAustralia as a whole has a substantial compliance program. The proposed transmission Compliance expenditure is a subset of the total program.

The compliance budget of $4.1m comprises the following items:

Electronic Security ($0.7M)

Following recent incidents EnergyAustralia has been upgrading the physical security of its substations against intrusion. Independent risk assessments have identified the need for enhanced security arrangements in the form of the installation of ID card readers to monitor and regulate entry to EA Zone and Sub-transmission substations. This transmission program is delivered as part of a broader program of works designed to address these issues for all EnergyAustralia network assets (both transmission and distribution).). This work is competitively sourced from externally contractors through a period contract of $1.5M pa over the next 5 years. This equates to a unit cost of $30K per substation or $0.7M for the 24 existing transmission substations.

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[26] This project was not included in EnergyAustralia's Annual Transmission Planning Report 2004 as the impact on the transmission network has only recently been identified.

PCB Removal ($1.0M)

This program comprises the replacement of PCB contaminated oil in 39 pieces of transmission equipment (Voltage Transformers and Current Transformers) at Mason Park, Peakhurst, Lane Cove, Mount Colah and Waratah substations.. This work has been mandated by the EPA and will be completed by December 2005. In most cases this will require the replacement of the contaminated equipment. Costs will also be incurred for oil removal and disposal.

Oil Containment at Substations ($1.05M)

EnergyAustralia is undertaking works at Mason Park and Tomago substations to mitigate the risk of polluting storm water and waterways with transformer and switchgear oil. The works involve the construction of suitable bunding at both sites and the installation of appropriate oil separation. The facilities will be designed in-house with construction externally contracted.

Fire Stopping ($0.2M) & Internal Doors ($0.8M)

Following extensive risk assessments undertaken by independent consulting engineers it was found necessary to install positive means to stop fire penetration within substations.

This program provides for fire rated internal doors and other measures to ensure that fire is prevented from moving through substations. This program is delivered as part of a broader program of works designed to address these issues for all network assets (both transmission and distribution). This work is competitively sourced from externally contractors via period contracts. This program does not include the sealing of large penetrations that involve other functions such as ventilation and structural building modifications.

Based on the schedule of rates within the period contract the cost per substation, based on a standard configuration is $34k per substation. There are 24 substations classified as Transmission for regulatory purposes which equates to a total cost of $0.85M

There are additional costs associated with this program associated with the need to provide security personnel to ensure no unauthorised access while the work is being carried out, and the requirement for safety supervisors.

Water Crossings ($0.16M)

As a result of a number of recent events involving watercraft colliding with overhead water crossings and damage to live cables a condition assessment has been undertaken of existing signage. The condition assessment revealed that signage is deteriorated and must be replaced and upgraded.

The unit cost of this work, based on a pilot program is $4,000 per sign. The Transmission share of this program involves the replacement of 41 signs at a total cost of $0.164M.

Asbestos ($0.15M)

Energy Australia is in the final stages of its asbestos removal program. In the case of Transmission facilities there are only two remaining substations that remain to be done (Lane Cove and Pyrmont). A unit cost of $67,500 per installation has been derived from the average cost of remediation at 38 other locations. This cost has been used as the estimated cost of completing this work at the two sites remaining.

Table 6 - EnergyAustralia's compliance program (2004-2009)

Compliance Program	TOTAL	2004/5	2005/6	2006/7	2007/8	2008/9
Electronic Security	0.7	0.25	0.26	0.21	0	0
OIL PCB	1.0	0.3	0.7	0	0	0
Oil Containment	1.1	0	0	0.53	0.53	0
Internal Fire Doors	0.83	0.20	0.10	0.31	0.11	0.11
Fire Stopping	0.2	0.1	0.1	0	0	0
Water Crossing	0.16	0.16	0	0	0	0
Asbestos Removal	0.15	0	0	0.15	0	0
TOTAL COMPLIANCE	**4.1**	**0.9**	**1.2**	**1.3**	**0.6**	**0.1**

3.5 EXCLUDED PROJECTS

EnergyAustralia proposes that projects with a total of $109.7m (plus the costs arising from customer connections and the Haymarket Tunnel variation) be regarded as excluded projects. Proposed Excluded projects comprise

- Major Inner Metropolitan 132kV Network Development $35.6m
- Replacement of Feeders 908/909 $36.7m
- Replacement of Ourimbah substation $25.7m
- Lower Hunter 132kV System Development $11.6m
- Major Customer Connections Indeterminate
- Haymarket Tunnel Variation Indeterminate

Total **$109.7m** (plus customer connections and Tunnel variation)

Whilst these proposed excluded projects are a large percentage of the total submission, the bulk of the exclusion lie in three large projects which amount to more than 40% of the proposed budget.

There is considerable uncertainty involved in all the proposed excluded projects which make their inclusion under any proposed ex-ante cap likely to result in significant over or under estimation of the cap.

The proposed exclude projects are described below.

Excluded Project 1 - Major Inner Metropolitan 132kV Network Development

Need for Project

Both TransGrid (refer to NSW Annual Planning Report 2004) and EnergyAustralia have identified that within the next 5 years, action will need to be taken to address network constraints on the inner metropolitan and southern Sydney 330kV and 132kV networks. Failure of either the Sydney South – Beaconsfield West or Sydney South – Haymarket 330kV cables and any of approximately 30 other critical circuits or transformers may result in the rating of some remaining elements being exceeded. EnergyAustralia's System Reliability Planning Standards state that "because there are a large number of critical elements within the system it has been decided to expand the security used in planning the supply to the CBD and inner suburbs to be more in line with international practice by considering a simultaneous outage of cable 41 or 42 and any 132kV feeder or 330/132kV transformer and outage of any section of 132kV busbar"[27].

Constraints

Within the next 5 years, 330kV feeders 41 & 42, 132kV feeders 910/1 & 911/1 and TransGrid's Sydney South transformers No. 1, 2, 4, 5 & 6 will reach capacity in the event of a number of single or double contingency outages. Feeder 41 is forecast to be constrained from 2005, feeder 42 from 2008, feeders 910/1 & 911/1 in 2010 and the Sydney South transformers in 2009.

Driver for Project

Without this project, Service standards are forecast to not meet minimum reliability requirements under single contingency outages, such that corrective network augmentation or non-network alternatives are required.

Possible Options

Joint planning with TransGrid is required to determine how the above mentioned constraints will be addressed. TransGrid have identified the following options:

- Tuning of Load flows and Reinforcement of EnergyAustralia's 132kV network

  Options to reinforce the 132kV network include the installation of phase shifting transformers to control power flows, installation of additional 132kV cabling and changing series reactors throughout the network.

- Establishment of an additional 330/132kV substation and associated 330kV supply
- Local generation
- Demand management

Optimisation of options to tune power flows is significantly influenced by changes to TransGrid's system and by proposed replacement work on EnergyAustralia's system. In

[27] EnergyAustralia's Network Management System Procedure, Document No.SE-T001, Page 2

particular, if feeder 908/909 is replaced with a feeder from Bunnerong-Kurnell, the sizing of reactors will be different if 908/909 was replaced with a Bunnerong-Canterbury feeder. Similarly the type/cost of phase shifting transformers will depend on the network configuration.

EnergyAustralia have included an allowance under the cap to cater for minor works early in the Regulatory period. It is anticipated that these works will defer major expenditure to later in the regulatory period.

EnergyAustralia envisages that major expenditure will be require later in the period comprising:

- Install phase shifting transformers at Chullora 2008 $17.9m
- Provide connections to a new TransGrid 330/132kV supply point $18.4m

EnergyAustralia's original estimate for this project was:

- Install phase shifting transformers at Chullora $13.8m[28]
- Provide connections to a new TransGrid 330/132kV supply point $18.0m

Project Costs 2004-09

EnergyAustralia's estimate of expected cash flows[29] for this project are.

2004/05	2005/06	2006/07	2007/08	2008/09	Total
$0m	$1.2m	$11.8m	$13m	$9.7m	$35.6m

However due to the uncertainty over issues such as the price of phase shifting transformers, the location of TransGrid's proposed substation, and feeder routes it is not possible to give an accurate indication of what the costs of this project will be.

Reasons to exclude from Cap

There are two major reasons to treat this project as an excluded project rather than including it under the cap.

- The value of this project is approximately 15% of the total capital budget.
- There is considerable uncertainty over the scope of the project and the magnitude of expenditure.

The TransGrid 330kV and EnergyAustralia 132kV transmission system are parallel systems. Planning and development of these networks cannot be carried out independently. Due to the interdependence between the these networks, and the uncertainty concerning the type of future augmentation works, forecasting capital expenditure on the Inner Metropolitan 132kV development is extremely difficult. EnergyAustralia and TransGrid are in the process of joint planning. Power flow analysis is being carried out to determine possible options to meet the

[28] Differences relate to Increased phase shifting transformer cost $1.5m, CB control $1m, project management $0.6m, contingency $1m.
[29] Real $2004. Note the probability of completion outside the regulatory period results in expected costs 2004-9 being marginally less than total project cost.

constraints. Once the planning and loadflow analysis is completed, EnergyAustralia and TransGrid can then determine their respective capital requirements. EnergyAustralia requires TransGrid to confirm what they are doing before it can determine what works it needs to undertake, how much it will cost to augment its network and in what year this expenditure will occur.

There is considerable uncertainty over the cost of the proposed works for the following reasons:

- There is uncertainty in the price of quadrature regulators. It depends largely on the phase angle. Budget estimates have provided a price range of between $3m and $7.5m each. EnergyAustralia have used the average of these figures in its estimates.
- The uncertainty in the location of a future 330/132kV supply point. No site has been selected. Without an identified site the lengths and routes to connect this substation to EnergyAustralia's system are unknown.
- Prior to developing the new supply point EnergyAustralia and TransGrid are committed to seeking demand management alternatives to defer augmentation. If successful these measures may allow the deferral of major expenditure into the next Regulatory period.

Excluded Project 2 - Feeder 908/9 Replacement

Need for Project

Feeders 908/909 are two aged and unreliable 132kV gas filled cables located between Bunnerong and Canterbury Subtransmission Substations. These cables are 48 years old, have a route length of 15.4km, and are EnergyAustralia's oldest 132kV cables. Only 101m of spare cable is left and spare cable can no longer be sourced from manufacturers. Since 1990, there have been 5 major faults on these cables with repair times varying between 3– 12 months.[30] These cables form a critical part of the supply to Bunnerong and also provide about 150MVA capacity between the Sydney South supply point and the inner suburbs of Sydney. The existing feeder route includes 3km within the boundary of Sydney Airport and 800m under traffic lanes in General Holmes Drive. Both these locations are undesirable in regards to repairing faults due to the severe working restrictions.

Driver for Project

Replacement of aged assets.

Possible Options

There are two possible options.

[30] It should be noted that while 908/909 are out of service for repairs, EnergyAustralia's transmission system is vulnerable to the impact of further outages.

Option 1

Option 1 involves the installation of new cables (larger rated cables than existing) between Kurnell and Bunnerong Subtransmission Substations. This route (6.3km) includes an underwater crossing of Botany Bay.

Option 2

Option 2 involves replacing the cables between Canterbury and Bunnerong, but following a different route (17.9km) to those existing feeders, avoiding Sydney Airport and other extremely busy transport routes.

It is envisaged that larger sized cables than those existing will be used to cope with present system fault levels and provide additional capacity.

Project Costs 2004-09

EnergyAustralia's estimate of expected cash flows[31] for this project are:

2004/05	2005/06	2006/07	2007/08	2008/09	Total
\$0.4m	\$1.5m	\$16.4m	\$12.4m	\$6.0m	**\$36.7M**

A tender was recently issued to carry out a route optimisation study for possible feeder routes. The outcome of this process will be a feasibility study assessing the viability of possible feeder routes. In regards to option 1, there are many unknowns including environmental costs, feeder route and submarine crossing installation details. It is difficult to estimate what the actual cost of this project will be.

EnergyAustralia's original submission estimated project costs as:

	2004/05	2005/06	2006/07	2007/08	2008/09	Total
Option 1	0.4	2.0	23.7	10.0	0.0	**\$36.1M**
Option 2	0.4	8.1	30.0	10.0	0.0	**\$48.5M**

Option 1: Cabling costs assumed to be a double circuit 1200mm^2 installation consisting of:

- Submarine cable installation, 3.6km at \$4M/km.
- Other cable installation, 4.5km at \$3.4M/km.
- Substation costs - \$4.5M
- Project Management - \$2.0M

[31] Real \$2004

The estimate does not include significant environmental costs, or other issues for the crossing of Botany Bay. It assumes the most direct cable route, no construction delays, no allowances for tunnelling, 100% roadway installation [32] and 20% rock[33] for the land component.

Option 2: Cabling costs assumed to be a double circuit 800mm^2 installation consisting of:

- Cable installation, 16km at $2.85M/km.
- Substation costs - $2M
- Project Management - $1.0M

SKM Consultants have provided estimates for both options as follows:

- Option 1 - $49M with an accuracy of + - 15%
- Option 2 - $59M with an accuracy of + - 15%

Note: Environmental and community concerns make the timing of this project difficult to determine

Reasons to exclude from Cap

There are two major reasons to treat this project as an excluded project rather than including it under the cap.

- The value of this project is approximately 15% of the total capital budget.
- There is considerable uncertainty over the scope of the project and the magnitude of expenditure. Uncertainties arise from
    - Lack of certainty over whether a submarine crossing is feasible from a community and environmental perspective. Should submarine crossing not be possible project costs may rise by more than 33%
    - Uncertainty over the route and installation options associated with a submarine crossing.

Excluded Project 3 - Ourimbah Sub-transmission Substation Refurbishment

Need for Project

Equipment Condition

Ourimbah Subtransmission Substation is fitted with three 60MVA 132/66kV transformers and is 45 years old. The firm capacity of the supply is 132MVA. The substation contains a substantial amount of aged equipment that is reaching the end of its technical life and will need to be replaced prior to 2010. An assessment made by Sinclair Knight Merz (SKM) consultants largely aligns with EnergyAustralia's assessment of the condition of the substation.

[32] Allowance for traffic control and roadway reinstatement along the whole route
[33] Assumes that 20% of route will be costly to excavate due to rock

It is not possible to replace all the aged or constrained equipment in their current location without excessive interruptions to customers. Some items of equipment do not need to be replaced for 5-10 years. However it is not considered to be a prudent investment to spend a significant amount over the next few years replacing the poor performing equipment with respect to condition and then in 5-10 years rebuild the entire substation which would involve replacing all equipment (old and new).

Rating Issues

There are also potential loading issues at Ourimbah relating to both the firm rating of the substation and the rating of the 132kV busbars. The substation load forecast is shown below[34].

Table 7 - Ourimbah Forecast (MVA)

	Rating	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Summer	132.0	103.1	108.0	113.2	118.7	124.4	130.3	136.6	143.1	150.0	157.2
Winter	132.0	116.2	119.4	122.6	126.0	129.5	133.1	136.7	140.5	144.4	148.3

Highlighted cells indicate that the substation is forecast to be loaded in excess of its firm rating from 2009

Ratings take into consideration unequal sharing of load between the 132/33kV transformers.

The 132kV busbar at Ourimbah is expected to be overloaded in winter 2008 during an outage of feeder 958 at times of peak system load. Loadflow analysis was used to determine this timing in conjunction with the diversified subtransmission forecast.

The 33kV supplies to Lisarow, Berkeley Vale and Long Jetty from Ourimbah are all forecast to exceed their respective ratings over the next few years. These feeder constraints will need to be addressed.

The loading issues at Ourimbah are expected to addressed in the medium term if the conversion of Berkeley Vale substation to 132kV operation proceeds. This will address the loading issues on Ourimbah as shown below.

[34] Details from EnergyAustralia's 2004 Subtransmission Forecast – summer power factor (p.f.) = 0.92, winter p.f. = 0.95. Forecast assumes that Berkeley Vale remains as a 33/11kV substation.

Table 8 - Ourimbah Forecast less Berkeley Vale Zone Substation (MVA)

	Rating	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Summer	132.0	66.5	69.7	75.0	78.4	81.9	85.6	89.4	93.4	97.6	101.9
Winter	132.0	84.9	85.4	89.7	91.9	94.1	96.3	98.6	101.0	103.4	105.9

* A diversity factor of 0.9 was used for Berkeley Vale

The conversion of Berkeley Vale substation to 132kV operation will not address loading on the distribution system to Long Jetty or Lisarow supplied from Ourimbah.

Driver for Project

Need to replace assets and the need to uprate the Ourimbah 132kV busbar. Future down stream development of feeders and substations is also driving development.

Much of the electrical equipment at Ourimbah is will exceed its standard life in 2004. The replacement of Ourimbah is thus a key component of EnergyAustralia's strategy to keep the level of its transmission assets exceeding the standard equipment life to less than 10%. Replacement of Ourimbah is a key component of the strategy as the substation contains some of EnergyAustralia's oldest transmission assets[35]. (132kV circuit breakers, 33kV circuit breakers, capacitors).

Possible Options

Ourimbah currently supplies Berkeley Vale, Long Jetty and Peats Ridge zone substations, Bangalow Chittaway pumping station at 33kV and the State Rail Authority at 66kV. It supplies almost 48,000 customers.

SKM have provided four options (three based on capacity and one based on age) and associated estimates to replace and uprate Ourimbah whilst maintaining supply to customers. These estimates range between $21.9-25.3M. These estimates are substantially higher then EnergyAustralia's previous estimate. The least cost option does not include the purchase of additional land and relies on an agreement being reached with all landowners. The purchase of the additional land has been estimated at $3.0M. The SKM report considers Ourimbah replacement in isolation. However a Value Management Study on the Southern Central Coast is underway and so far the study has highlighted 26 different options to address issues in the Southern Central Coast. Many of these options impact on Ourimbah and the Central Coast 132kV network. The final recommendation of the VMS will directly impact on the future development of Ourimbah.

For example, if may be cost effective to convert Long Jetty substation to 66kV operation and reconstruct Ourimbah to provide increased capacity a 66kV. This would avoid th need to install an additional 33kV feeder from Ourimbah to the Long Jetty area. Such a decision would have an impact on the scope of the proposed refurbishment project.

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[35] SKM's Aged Asset Replacement Projection – EnergyAustralia Transmission Network - Appendix D

Project Costs 2004-09

EnergyAustralia's estimate of the expected cash flows[36] for this project are now.

2004/05	2005/06	2006/07	2007/08	2008/09	Total
$0.1m	$2.9m	$9.3m	$9.7m	$3.6m	**$25.7m**

There is considerable uncertainty over the project cost at this stage. The final construction cost will depend on which of the possible options is developed and may vary substantially to the SKM estimates

Reasons to exclude from Cap

There are two major reasons to treat this project as an excluded project rather than including it under the cap.

- The value of this project is exceeds 10% of the total capital budget.
- There is considerable uncertainty over the scope of the project and the magnitude of expenditure.

Investigations are underway to determine how to best address constraints at Long Jetty and Lisarow zone substations and the associated 33kV network. 33kV, 66kV and 132kV options are being investigated and the final outcome will have a direct impact on works at Ourimbah. Increasing the operating voltage to 66kV doubles the capacity of the subtransmission system and provides scope for future load growth without the need to install additional subtransmission feeders. The most likely scenario is for Ourimbah to be developed into a substation consisting of two x 132/66kV transformers and one x 132/33kV transformer with Lisarow and Long Jetty both converted to 66/11kV zone substations[37]. A new 33kV, 66kV and 132kV busbar will need to be constructed at Ourimbah as part of the development.

Excluded Project 4 - Customer Connections

From time to time, major customers approach EnergyAustralia requesting or discussing the possibility of electricity supply. Due to the amount of load required by these major customers and the location of the load, the least cost way of supplying their needs may be through connection to the 132kV network. Sometimes this connection would be a Transmission Asset, and capital expenditure would be regulated by ACCC. However in some cases, depending on location, the customer connection may be a Distribution Asset, and capital expenditure would then be regulated by IPART. Many of these approaches by customers do not eventuate into a firm project, some are delayed for many years and the scope of projects often changes.

Customer Connections would be treated in accordance with EnergyAustralia's policy ES8 Capital Contributions Guidelines. Whilst EnergyAustralia would require a capital contribution from the customer to cover the cost of dedicated connection assets, it would generally fund any

[36] Based on SKMs Option 2 adjusted for material and labour cost increases.
[37] A mix of transformers (132/33kV & 132/66kV) are required if Ourimbah supplies voltages at 33kV and 66kV volts

shared assets which may be involved in the connection. In some cases this may require substantial capital expenditure.

Whilst EnergyAustralia receives numerous connection enquiries which would involve a transmission connection, no customer connections to the transmission system have proceeded in the last 10 years. Due to the extreme uncertainty in requests for electricity supply from customers, the fact that such requests can occur at anytime without any notice and the uncertainty of costs, it is proposed that all capital expenditure on customer connections be excluded from the ACCC cap.

Known possible customer connections comprise:

Customer 1 – South Sydney Area

Load – Customer 1 is presently supplied at 33kV and has a load of 42MVA The customer is forecasting an additional 50MVA load over the next 20 years

Supply Arrangements – Supply options include an upgraded 33kV supply or a 132kV connection. Given the magnitude of the ultimate load a 132kV connection is the preferred option. It is unknown at this stage whether the assets will be considered transmission or distribution.

Status – Awaiting response from customer with planning and loadflow analysis required before the project proceeds

Cost - $25M-$50M (initial budget estimate only)

Sydney Water

Load – Considering a range of options to meet the future water supply requirements of the Sydney region. Possible options include desalination and requirements may include a single 150MVA supply or several or several 30MVA supplies.

Supply Arrangements – EnergyAustralia proposes 132kV connection for the 150MVA supplies. The required supply arrangements will depend on the site of the proposed plant. There are a number of locations where supply could be sourced including Kurnell, Peakhurst, Beaconsfield West and Mason Park substations.

EnergyAustralia proposes 33kV or 132kV connection for the 30MVA supplies. There are a number of locations where supply could be sourced and many of the possible connections would be considered distribution assets.

Status – Timing of project is uncertain and plant could be located outside EnergyAustralia's supply area.

Cost - $0M-$200M plus (Depends on number and size of different sites and final plant configuation).

Customer 2

Load – The customer has forecast approximately 45MVA of load on the Central Coast.

Supply Arrangements – Under the proposed loading scenario, the anticipated supply will be 132kV with connection to feeder 957 which passes directly adjacent to the works site. Likely supply arrangements would require establishment of transmission busbar with two dedicated customer supplies. The likely cost to EnergyAustralia is between $5-$15M depending on supply arrangement and the extent of capital contribution. This load represents a significant increase to the Central Coast 132kV system and would require an advance to the 132kV augmentation works on the Central Coast. Detailed planning is required once the customer confirms loading and project commitment.

Status – Awaiting customer advice and negotiation prior to proceeding with the project.

Cost - Unknown

Customer 3

This customer proposes to establish a new industrial area in the lower Hunter. The proposed development has potential to become one of Australia's largest industrial areas. The developable area is approximately 900 hectares and lies to the immediate south-west of the township of Kurri Kurri in the Lower Hunter Valley. The timing, type and scale of future industrial development will largely depend on market forces however the proposal does provide scope for heavy industry and associated potential for very large electrical loads.

Load – (5-20) MVA with 33kV connection from Kurri STS, then up to 80MVA with the existing 132kV feeder capacity.

Supply Arrangements – Whilst initial connection will be a distribution system supply at 33kV any substantial increases in load would require 132kV supply. The provision of up to 80MVA of connected load has been investigated by EnergyAustralia with planning and protection reports identifying a proposed double tee 132kV connection to the existing feeders 96U and 96W as being feasible. This arrangement would involve creation of two new dedicated 132kV feeders to the customer substation site from the existing feeders just south of John Renshaw Drive. The establishment of a new 132/11kV substation on the site will provide a connection point for the 11kV feeder distribution network for this stage of the development. Supply to the newly constructed 132kV substation would then be provided by having one of the two tees in service at any one time. An auto changeover scheme would alternate between the two feeders in the event of the loss of one feeder. This provides the supply security required at the new 132kV substation. A momentary interruption to supply would be experienced during the auto changeover switching. If the supply demands are high enough (greater than around 80MVA) then a third 132kV feeder may also be required dependent on the Lower Hunter 132kV arrangement at the time. The present proposal stands as a 33/11kV substation connected from Kurri STS with a load starting at 5MVA in 2005 developing to 20MVA dependent on customer take up. Beyond this load the 132kV proposal above would be the likely arrangement.

Status – Concept brief and Instruction for Project Development for the first stage of the 33/11kV substation has been issued

Cost - Being determined for the substation only

Tomago (ex Austeel Site)

The Regional Land Management Corporation (RLMC) currently has a Call for Proposals (CFP) for the ex Austeel Site at Tomago[38]. The RLMC is encouraging the development of this site.. Development at this site will be subject to the land zoning and preferences required by RLMC as detailed in the CFP. This site has a land area of around 470 hectares and dependent on the final land use the load could vary from low use industrial to a significant single plant.

Load – Based on typical industrial land use for the Hunter the load would be in the range of 14-38MVA, but with the uncertainty of the prospects for this land the load value could be as high as several hundred MVA for a large single plant.

Supply Arrangements – Unknown, but there would be influence for the 132kV supply from Waratah West – Tomago and the Beresfield – Tomago feeders along with Tomago STS.

Status – Call for proposals close in Nov 2004.

Cost – Unknown at this stage

Kooragang Island

The Regional Land Management Corporation (RLMC) currently has a Call for Proposals (CFP) for five sites on Kooragang Island. Refer to five sites detailed below. The RLMC is encouraging the development of these sites. There are areas of land available for development on Kooragang Island including the site that was proposed for Protech development. The RLMC is Kooragang Island is supplied via a general 33kV reticulation network from Waratah 132/33kV substation and Kooragang West Switching Station. Much of the existing supply network is approaching capacity and service-life limitations. The existing peak load at Kooragang is around 44MVA, however scope exists for incremental up-rating to supply load of around 60MVA. Beyond this, the load could not be adequately supported from the existing 33kV network. Establishing 132kV supply including a 132/33kV substation on Kooragang Island would be the logical arrangement if additional load greater than 20MVA was sought (subject to Waratah 132/33kV STS works). Whilst it is likely that an 132kV supply would be a distribution asset, works may involve the transmission network.

The five sites on Kooragang Island that are contained in the CFP are:

Site A - Cormorant Rd – Coal Terminal

This has a land area of around 164 hectares and it is most likely that the site would be used as a coal loader. The Australian Rail Track Corporation (ARTC) is proposing to upgrade the rail infrastructure of the Hunter coal chain that will improve the capacity of the Hunter rail coal chain from 85Mtpa to over 100Mtpa. BHP Billiton and three other coal producers are considering increasing coal production by around 30Mtpa over the next 5-10 years and an additional third coal loader at the Newcastle Port maybe required to address the increased coal production. This site would be an ideal location for a coal loader. The amount of load will depend on the technology used and the location of the rail dump to the boat load. A load of around 15-20MVA

[38] Regional Land Management Corporation, Port Related Development Opportunities at Kooragang Island and Tomago, Newcastle (NSW) – Call for Proposals

would be expected. This value would be high enough to consider the implementation of the 132kV supply option for Kooragang Island.

Site B - Heron Rd – Bulk & Grain Terminal

This has a land area of around 7.6 hectares and dependent on the final land use the load could vary from a terminal to other industry that requires this type of location. Estimating load values for this site would not be prudent with little information at this stage of the call for proposals.

Site C - Greenleaf Rd – Bulk & Grain Terminal

This has a land area of around 10 hectares and dependent on the final land use the load could vary from a terminal to other industry that requires this type of location. Estimating load values for this site would not be prudent with little information at this stage of the call for proposals.

Site D - Former Solids Emplacement Site – Suitable Uses

This has a land area of around 258 hectares and dependent on the final land use the load could vary from 8- 21 MVA based on typical industrial land use for the Hunter considering this sites limited access to the river.

Site E - Teal & Raven St – Suitable Uses

This has a land area of around 7 hectares, estimating load values for this site would not be prudent with little information at this stage of the call for proposals.

Excluded Project 5 - Lower Hunter 132kV Network Development

Need for Project

EnergyAustralia is currently constructing Beresfield Subtransmission substation. This substation was constructed to address a range of long term supply issues for the Lower Hunter Area including loading on Kurri and Tomago Subtransmission Substations and the associated 33kV networks. TransGrid are committed to installing a 330/132kV transformer at Waratah West Substation. These projects are part of the first stage in the development of the Lower Hunter 132kV Network.

By summer 2005/06, loads on feeder 95W & 952/3 will exceed their respective emergency ratings under a single contingency outage. By 2008/09 feeders 950, 95N, 95W, 961/1, 96F/1A, 96Z/1 and 96Z/2 will also be exceeding their respective ratings.

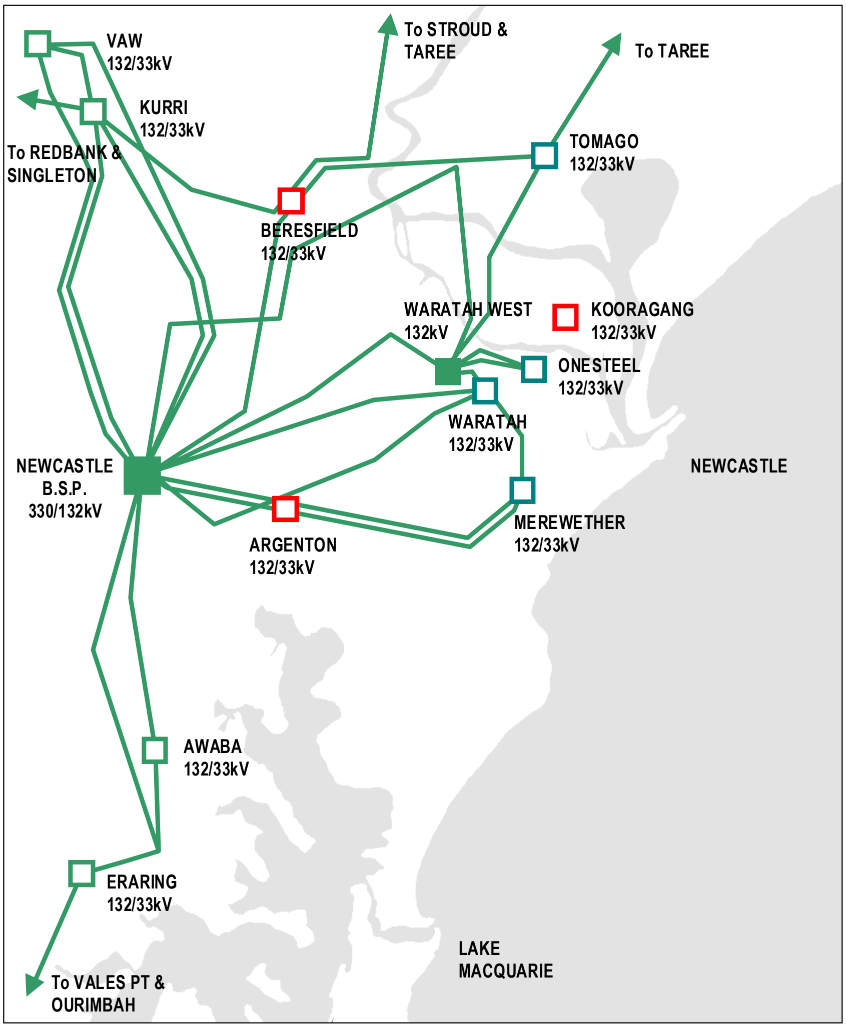
In recent months, the security standard for supply to areas within EnergyAustralia's franchise area has been under review. Recent events in Newcastle that involved concurrent outages at TransGrid's main supply point to Newcastle and on EnergyAustralia's subsidiary system came within moments of causing major wide-spread interruptions in the area. This event and the general pressure on supply into the Newcastle and Hunter region has prompted a reassessment of the security standards offered to areas outside the Sydney CBD.

TransGrid and EnergyAustralia are currently discussing a change to the established planning standards. Ultimately however, EnergyAustralia believes this issue is one that requires government involvement to set minimum standards for various sectors of the community. This is currently being pursued with the NSW government. A change in the standards would have a major impact on the development of 132kV supply to the lower Hunter.

Driver for Project

Without this project, service standards are forecast to not meet minimum reliability requirements under single contingency outages, such that corrective network augmentation or non-network alternatives are required.

Figure 5 - Lower Hunter 132kV Network



Possible Options

<u>Option 1</u>

The second stage of the Lower Hunter 132kV Development was to involve the construction of 132kV lines Newcastle – Beresfield and Waratah West – Tomago and the installation of a second 330/132kV transformer at Waratah West. However there is some doubt that the proposed second stage works are the best long term strategy and the most prudent investment to be implementing. TransGrid need to determine if this option is the best solution.

The two 132kV feeders would be expected to cost $9.5M and the Waratah West 132kV arrangements $4.0M. 50% of the works associated with the upgrade of Waratah West would be attributable to ACCC. Investigation of line routes is presently in progress, accurate costing for this project will not be known until initial route investigations are complete.

Option 2

TransGrid to provide 132kV supply to EnergyAustralia from its existing substation at Tomago. Three 132kV feeders (6.5km long) would need to be constructed from TransGrid Tomago to EnergyAustralia Tomago and would be expected to cost $8.6M. A new feeder to Beresfield (11km) would need to be constructed at an estimated cost of $4.6M. The proposed route would transverse rivers and wet lands impacting on the cost of the project. An alternative would involve the construction of 7km of dual circuit feeder between Tomago TransGrid and feeder 96F forming a Tomago TransGrid – Stroud and Tomago TransGrid – Beresfield feeders. The upper level budget estimate for these works would be $5.2M. There is also a need to consider protection and communication for intertripping from Tomago to Waratah West and Beresfield to Kurri. Based on $50,000 / km for retro fit of the existing OHEW[39] for Tomago to Waratah West and $40,000 / km for the Kurri to Beresfield section, a total of $1.1M. Protection upgrades would be estimated to cost $0.66M. The full cost for this option is not yet known.

Option 3

TransGrid to construct a new 330/132kV substation in the vicinity of the Kurri Smelter. Two feeders would need to be constructed from the TransGrid substation to the smelter. The expected cost of these works would be $0.7M, based upon 2km of feeder at $350,000 per km. Other feeder arrangements would be expected to cost $1.15M and include rearrangement of feeders 95L, 96W, 96F, 96B and 132kV feeders for Taree/Stroud at Beresfield or Tomago.

This work will be impacted by

- the proposed relocation of feeders 96A, 96B, 96U, 96W and 95L in the vicinity of Kurri and Buchanan included in Project 20
- the work required to provide supply to Customer 3.

It is possible that TransGrid or EnergyAustralia work associated with this option may be advanced so that it can be integrated with works required to cater for the above issues..

Option 4

TransGrid to construct a new 330/132kV substation at Richmond Vale. Two new 132kV feeders would need to be constructed connecting to existing feeders 96U and 96W. The cost of this construction would be $2.22M based upon $370,000 per km for 6km of construction. Two new 132kV feeders would need to be constructed connecting to existing feeders 96A and 96B. The cost of this construction would be $4.44M based upon $370,000 per km for 12km of construction.

[39] OHEW – Overhead Earth Wire

One new feeder direct to Beresfield would also need to be constructed and the expected route length is 21km and the works would expect to cost $8.2M. Protection and communications for feeder 9NA and 962 is estimated at $0.6M.

This work will be impacted by

- the proposed relocation of feeders 96A, 96B, 96U, 96W and 95L in the vicinity of Kurri and Buchanan included in Project 20
- the work required to provide supply to Customer 3.

It is possible that TransGrid or EnergyAustralia work associated with this option may be advanced so that it can be integrated with works required to cater for the above issues..

Project Costs

Determination of the option adopted will be the least cost solution. As substantial TransGrid work is required the adopted option will be the result of joint planning.

Due to the uncertainty over what proposal will be implemented, the location of substations, and feeder routes it is not possible to give any accurate indication of what the costs of this project will be.

EnergyAustralia's estimate of expected cash flows[40] for this project are:

2004/05	2005/06	2006/07	2007/08	2008/09	Total
$0.2m	$3.3m	$5.2m	$2.7m	$0.2m	**$11.6M**

* This was based upon option 1. (Budget estimate only)

Reasons to exclude from cap

It is proposed to exclude this from the cap due to the uncertainty of the project scope and the potential for major cost increases.

The amount of 132kV feeder construction and the network configuration will rely on the location of the any new TransGrid supply point and is expected to cost EnergyAustralia tens of millions of dollars. For the above mentioned options, protection and communication schemes will need to be reviewed and developed. The cost of such works would be millions of dollars and will depend ultimately on the network configuration selected. Detailed loadflow and fault level analysis will need to be undertaken, detailed estimates for a range of options completed and route option studies carried out. It will also need to be determined whether options are physically possible and acceptable to the community.

The TransGrid 330kV and EnergyAustralia 132kV system are interrelated systems. Planning and development of these networks cannot be carried out independently. Due to the interdependence between the these networks, and the uncertainty concerning the type of future augmentation works, forecasting capital expenditure on the Lower Hunter 132kV development is extremely difficult. EnergyAustralia and TransGrid are in the process of joint planning. Power

[40] Real $2004

flow analysis is being carried out to determine possible options to meet the constraints. Once the planning and loadflow analysis is completed, EnergyAustralia and TransGrid can then determine their respective capital requirements. EnergyAustralia requires TransGrid to confirm what they are doing before it can determine what works it needs to undertake, how much it will cost to augment its network and in what year this expenditure will occur.

Excluded Project 6 - Variation Claim for Haymarket Tunnel

As part of the Haymarket project EnergyAustralia constructed a cable tunnel between Haymarket substation and Surry Hills. The construction company has lodged a substantial variation claim in relation to this project. As the outcome of this claim is uncertain EA are proposing that the cost of settling this claim should be considered as an excluded project. EnergyAustralia will provide details of the claim to ACCC on a confidential basis. It is proposed that an allowance for the claim should be provided as an allowance additional to the $234.7m proposed budget.

3.6 NON-SYSTEM

EnergyAustralia has not revised its capital program for non-system spend in light of the ACCC's introduction of the ex-ante capital framework.

3.7 INDEXATION OF THE FIRM CAP

3.7.1 Input costs

Capital Expenditure costs comprise a combination of labour, equipment and construction costs. As a result of the shift to an ex-ante regulatory framework it is essential that capital expenditure forecasts be appropriately indexed for expected real increases in these costs.[41]

In terms of labour costs, average weekly earnings have increased, on average, 1.4% above inflation over the last 3 years. NIEIR forecasts that earnings will increase 1.2% in real terms between 2004/05 and 2007/08.[42] Due to the shortage of skilled labour currently faced by transmission and distribution companies, EnergyAustralia believes that labour costs across the industry will rise above the average weekly earnings assumed by NIEIR. For the purposes of indexing the labour component of future capital expenditure, a real increase of 1.5% per annum has been assumed in EnergyAustralia's cost estimates.

Construction costs, according to the ABS's Producer Price Index for Materials used in Non-dwelling construction (Sydney), have increased by 1.4% in real terms over the last 2 years. BIS-Shrapnel forecast that the implicit price deflator for non-dwelling construction in New South Wales would average 3.2% above inflation in the next 5 years.[43] As a result, it is assumed in EnergyAustralia's cost forecasts that construction costs will increase by 3% pa in real terms over the next regulatory period.

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[41] While real movements in prices should be recognised in any regulatory framework, it is critical in an ex ante framework that the cap adequately adjusts for such movements. This is due to the proposed disallowance of expenditure over the cap, even if driven by exogenous factors beyond the reasonable control of the business.
[42] Energy Working Party Conference, Melbourne (July 2004)
[43] Building in Australia 2004-2019, 24th edition

It is difficult to provide forecasts of equipment costs due to the range of system equipment that EnergyAustralia purchases. Due to the fact that a large number of Transmission and Distribution businesses have significantly increased their capital expenditure program, and despite having a range of period contracts in place for particular types of equipment, EnergyAustralia is currently experiencing difficulties in sourcing particular types of equipment. For example, demand for power transformers and concrete power poles has placed considerable pressure on local producers to meet these demands and, in the case of power poles, it has been necessary to seek alternative suppliers. The net result of these factors is likely to mean that equipment prices will increase in real terms. In developing these the capital forecasts, an allowance of 1.5% per annum has been made to allow for the expected increase in equipment prices.

EnergyAustralia's has factored in the above assumptions of real increases into its forecast costs of labour, materials and construction and this has been incorporated in the estimates for the proposed capital program.

EnergyAustralia's proposal

EnergyAustralia proposes that the cap be linked to the key assumptions outlined above for input costs and should adjust automatically if the actual cost changes for these inputs are different to the assumed costs. EnergyAustralia proposes that the real increases in factor prices assumed above be compared to the results in the following ABS published data:

- Average Weekly Earnings (Seasonally Adjusted) Persons, All employees Total earnings Catalogue No. 6302
- Producer Price Index Catalogue No. 6427, Table 19 Materials used in other than House Building (Sydney) (data publicly available but not published)
- Producer Price Index Catalogue No. 6427, Table 11: Articles Produced by Manufacturing Industries - Electrical Equipment and Appliance Manufacturing (ANZSIC Code 2852 and 2859)

In the interests of simplicity, EnergyAustralia has given the three factors equal weighting. In order for the cap to adjust each year, EnergyAustralia proposes that data for the 12 months to March (ie: a 3 month lag) be used to index the capped expenditure for the following financial year (if required). Using March data will allow a new cap to be calculated if necessary, and will allow corresponding changes to transmission prices to be notified as required by May 15.

3.7.2 Exchange rate risk

A significant proportion (around 25%) of EnergyAustralia's equipment purchases are sourced from overseas and the prices of this equipment (ie switch gear and cables) are subject to variations due to changes in the exchange rate. This equipment is primarily priced in US dollars.

EnergyAustralia's proposal

EnergyAustralia proposes to work with the ACCC to identify a suitable basis for allowing for the impact of exchange rate variations on final capital expenditure.

3.8 IMPACT OF CAPEX PROGRAM ON OPEX

EnergyAustralia has reviewed its capex program in light of the ACCC's ex-ante framework. As mentioned in earlier submissions, there can be a correlation between spending on replacement and expenditure on maintenance. Typically, older assets require greater amounts of maintenance to maintain performance. Therefore, replacement of older and failing assets can be said to have the effect of reducing required maintenance. However, it is not a direct correlation in all cases and in fact often depends on the types of assets being replaced.

In the case of EnergyAustralia revised replacement program for transmission, the total increase in replacement spending over five years compared to our initial claim (September 2003) is $41m. EnergyAustralia believes this to be a relatively small increase in the replacement program that will have a negligible impact on opex in the 2004-2009 period due to the types of equipment being replaced.

4 SERVICE STANDARDS

In its draft determination, the ACCC imposed a financial incentive on EnergyAustralia to meet service standards targets as measured by transmission availability. The reliability target was set on the basis of GHD's recommendations, which were based on average system performance statistics.

The ACCC also required EnergyAustralia to measure transmission circuit availability with the inclusion of:

- transformers and reactive plant, in accordance with the proposed standard definition
- significant lengths of new 132kV lines and other equipment, resulting from the re-classification of some assets from distribution to transmission during the 1999-2004 regulatory period.

In addition, the ACCC required EnergyAustralia to report on the other performance measures contained in the service standard guidelines.[44]

In the response to the draft determination, EnergyAustralia set out its case that aggressive reductions to operating costs made by ACCC in its draft determination could seriously impact EnergyAustralia's ability to meet the service standard targets that had been set. We also argued that failure by ACCC to provide a revenue stream to cover critical capex projects in the 2004-2009 regulatory period also has the potential to fundamentally impact EnergyAustralia 's ability to meet its service standards.

It is within the context of significant reductions to revenue as proposed in the draft determination that EnergyAustralia believes that an additional one percent revenue penalty for failure to meet services standards targets results in a double revenue impact on EnergyAustralia which could compound its ability to meet targets set in subsequent periods.

EnergyAustralia also raised a number of technical issues associated with the capture of data required by ACCC. It is this technical information that is discussed in the following sections.

4.1 TRANSFORMER AVAILABILITY

As mentioned above, the ACCC has required that EnergyAustralia record transmission availability with the inclusion of reactive plant and transformers. To date, EnergyAustralia has recorded transmission circuit availability manually using feeder information only. EnergyAustralia believes that the requirement to include transformer availability does not add value to the statistics due to the nature and configuration of EnergyAustralia's transmission system.

Parts of EnergyAustralia's network are considered to be a transmission network because the assets meet the Code's definition of transmission assets (ie. some assets operate at voltages of 66kV and above and operate in parallel, and provide support, to other transmission assets (usually 220kV and above)). There are significant sections of EnergyAustralia's network that

[44] ACCC Draft Determination for EnergyAustralia 2004-2009, p116.

operate at similar voltages to the defined transmission assets, but that are not captured by the definition because they operate radially.

Recording availability of transformers makes sense from a true TNSP perspective as transformer outages can have significant impacts on downstream supply. However, the situation is very different for a DNSP where the ramifications of single transformer outages are far less severe and will affect a far lower number of customers (if any). In most cases, a transformer outage has no direct impact on customers as substations usually have spare transformers in place to take load in the event of a single outage.

EnergyAustralia has a number of Bulk Supply Points that serve a very large number of customers that are not considered to be part of the transmission network because they are connected to radial parts of the 132kV system. In contrast, many of EnergyAustralia's transmission exit points are relatively small **zone** substations that serve a relatively small number of customers.

Furthermore, EnergyAustralia's network also consists of a number of transmission switching stations that do not contain transformers at all, but are critical to the performance of the transmission network. The service standards as defined by ACCC ignore switching stations and other critical elements of transmission circuits and instead require data capture for pieces of equipment that are often insignificant to the effective operation of the transmission system.

From EnergyAustralia's perspective, recording transformer availability for its transmission assets would provide a random sample of small and large transformers whose only characteristic in common is their connection to a transmission feeder. EnergyAustralia believes that such data would be of extremely limited value, and would not provide a representative sample of the impact of customers affected by transformer outages.

Furthermore, calculating availability statistics including transformer availability does not take into account the fact that transformers on EnergyAustralia's network are often taken out of service for maintenance or switching purposes. This type of activity is far more common for transformers than for feeders, and is far more common in a distribution network than in a true transmission network. Switching and maintenance activities typically do not impact on customers as this type of activity is undertaken during off-peak times or seasons.

Incorporating transformer availability in the availability statistics not only is of no value in terms of identifying the real impact of outages on customers, the collection of the data will also be resource intensive as EnergyAustralia has no systems in place to collect this data.

EnergyAustralia requests that ACCC remove the requirement to capture transformer availability data in its final determination because it is not relevant to the combined transmission/distribution network that EnergyAustralia operates.

4.2 REACTIVE PLANT AVAILABILITY

EnergyAustralia agrees that it is appropriate to report the availability of reactive plant as reactive plant has an impact on VAr flows and voltage levels on the transmission network.

5 OTHER ISSUES

5.1 HAYMARKET

The construction of the Haymarket – Campbell Street tunnel scope was changed due to water ingress and consequent additional costs for water treatment. References in this document refer to the costs to be indeterminate, as there are confidential matters still being negotiated between EnergyAustralia and the tunnel contractor for the Haymarket augmentation. Given the confidential nature of the negotiations, a report has been written by EnergyAustralia's legal team, and is included as Appendix 22. EnergyAustralia claims strict confidentiality for this report as the subject is a matter of legal privilege.

5.2 HOMEBUSH

The undergrounding of assets at Homebush Bay to facilitate the Sydney Olympic games was undertaken by EnergyAustralia and jointly paid for by EnergyAustralia, the Olympic Coordination Authority (OCA) and Sydney Organising Committee for the Olympic Games (SOCOG).

EnergyAustralia claimed $10m in its original submission for the portion of undergrounding costs paid for by EnergyAustralia. Subsequently, the ACCC requested condition reports for the assets that were replaced to verify whether the assets needed replacement or whether they were replaced for aesthetic purposes. These files have not been able to be located in the archives.

EnergyAustralia therefore believes that it is appropriate that it withdraw its $10m claim for the 1999-2004 period and reinstate this claim at a subsequent review when the original assets would have reached their asset life. EnergyAustralia will reinstate its claim at the depreciated value of the new assets in 2015.

5.3 OPERATING EXPENDITURE

The major share (80%) of operating costs relate to labour, whether employees or contracted services. EnergyAustralia's original submission made no allowance for real increases in labour costs.

EnergyAustralia's proposal

EnergyAustralia proposes that operating costs be adjusted for expected real increases in labour costs as part of this determination (as per the assumptions included for capital costs in outlined in section 3.7). Alternatively, actual operating expenditure could be reconciled against actual real increases in labour costs during an ex-post review at the end of the period. EnergyAustralia proposes that such a reconciliation should be based on the measure of Average Weekly earnings identified in section 3.7 of this submission.

5.4 PASS-THROUGH RULES

EnergyAustralia's comments in relation to the standard pass-through rules proposed by ACCC are included in Appendix 26.

6 ATTACHMENTS

Appendix 1	Replace 132kV feeder 908/909
Appendix 2	Ourimbah Subtransmission Substation Refurbishment
Appendix 3	Installation of Green Square Zone Substation
Appendix 4	Substation Equipment and Mains Replacement (confidential)
Appendix 5	Relocation of 132kV Feeders 96A, 96B, 96U, 96W & 95L
Appendix 6	Compliance Works
Appendix 7	Augmentation of Inner Metropolitan 132kV Network
Appendix 8	Lower Hunter 132kV Network Development
Appendix 9	Unconfirmed Customer Connections
Appendix 10	132kV Connections to Haymarket & Campbell St Substation
Appendix 11	Installation of Beresfield Subtransmission Substation
Appendix 12	Transmission Boundary Metering
Appendix 13	Kurri Subtransmission Substation Works
Appendix 14	132kV Network Development in Newcastle Western Corridor
Appendix 15	Gosford Subtransmission Substation Capacitor Installation
Appendix 16	Drummoyne Zone Substation Constraint
Appendix 17	Tomago Subtransmission Substation Works
Appendix 18	West Gosford Zone Substation Constraint
Appendix 19	Macquarie Park Zone Substation Constraint
Appendix 20	Upgrade 132kV Feeder 926
Appendix 21	132kV Development in Mid-Southern Central Coast
Appendix 22	Tunnel Arbitration (confidential)
Appendix 23	Project Status
Appendix 24	Excluded and Off-ramp projects (confidential sections)
Appendix 25	EnergyAustralia's Governance Procedure
Appendix 26	Pass Through Rules