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Dear Mr Rawstron

ELECTRANET SA TRANSMISSION NETWORK REVENUE CAP APPLICATION

NRG Flinders appreciates this opportunity to provide initial comment on the Transmission Network Revenue Cap Application lodged by ElectraNet SA on 16 April 2002.

For convenience, these comments conform to the structure and headings used in the application.

Cost of Capital

Cost of Equity Capital

While there may be arguments for the use of a longer-term bond rate in the determination of the risk free rate of return (ie 10 year bonds) it is noted that the ACCC has chosen to adopt the 5-year bond rate as a proxy for the risk free rate in recent determinations. In the interests of consistency, NRG Flinders would therefore support the application of the 5-year bond rate in this instance. This notion might also be argued as consistent with the need for periodic refinancing of debt by a capital-intensive business.

A nominal risk free rate of 5.90% has been quoted in the application based on the 40-day average yield on 10-year Commonwealth Government bonds as at 4 March 2002. Leaving aside the use of the 10-year bond rate, no justification has been provided for the use of this particular date. Presumably the relevant rate ultimately applied by the ACCC would be chosen to reflect prevailing market rates over an appropriate interval prior to the commencement of the regulatory period. This comment also applies to a range of other parameters to be established in the revenue cap (eg the applicable inflation rate).

It is argued in the application that the size of the capital investment program proposed by ElectraNet SA will expose it to greater interest rate risk under the cost of capital approach adopted by the ACCC, given the rapid growth in the level of new capital investment. However, this would appear to be a consequence of the ambitious investment program proposed rather than the valuation methodology itself.

The extent to which allowance therefore needs to be made for costs associated with swap options and interest rate hedges to manage exposure to future interest rate movements, as proposed in the application, will be influenced by the size of the capital expenditure program approved. It also needs to be recognised that future financing costs will presumably be taken into account at the next regulatory reset to reflect prevailing interest rates at that time.

In the determination of asset risk (for the purposes of beta calculations) it is claimed that ElectraNet SA represents a small firm in transmission terms, suggesting the need for an increment to its returns in comparison with its counterparts interstate. However, it would appear questionable that a firm with a (proposed) asset base of $1bn and annual revenue of nearly $200m could reasonably be described as a 'small' firm in asset risk terms. Consequently, the arguments in favour of higher rates of return to reflect small firm risk do not appear to be applicable to ElectraNet SA.

It is also claimed that the systematic risk of electricity transmission companies is likely to be higher than that of distribution companies. This is debateable given the range of risks faced by local networks, including the presence of distributed and embedded generation alternatives, local bypass risks and the greater susceptibility of reticulated networks to weather and related risks.

Cost of Debt

A proposed cost of debt premium of 1.72% is added to the risk free rate of return of 5.90% (based on the 10-year bond rate, as discussed above) to obtain a cost of debt of 7.62%. Once again, the proposed 10-year time horizon would need to be corrected, if the ACCC is to apply a consistent use of the 5-year bond rate.

The proposed premium is based in part on an assumed BBB+ credit rating. To be accepted, this figure would presumably need to be validated by an appropriate credit rating agency. It is also noted that this figure is influenced by key financial performance indicators of the business, which in turn will depend on the financial parameters approved in the final revenue determination.

It is noted that a significantly lower risk premium of 1.2% was applied in the recent Powerlink revenue cap decision.

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Calculating Cost of Equity Capital

In addition to the conventional analysis used to calculate the cost of equity capital, it is asserted that asymmetric risks faced by transmission companies warrant the adoption of a premium in addition to the cost of equity capital. A number of arguments are advanced in support of this claim.

It is argued that competition from gas transmission increases the risk of asset stranding. However, this risk should presumably be captured in the equity beta, which makes allowance for systematic asset risk.

Asset valuation risk also cited as an additional risk factor. However, this is fundamental to the nature of the regulatory framework, and not a risk for which a regulated entity is entitled to additional compensation. The TNSP is clearly incentivised to manage the risk of optimisation through efficient network investment, and to remove this incentive would weaken a central element of the regulatory framework.

It is also claimed that a range of policy and operational reviews impacting on the NEM increase the level of uncertainty. It would appear that this factor is common to all participants operating in the NEM, not limited to transmission entities. To apply an earnings premium to 2008 to account for a range of policy reviews under way at the present time would not appear to be a reasonable proposition. A similar comment applies to the alleged uncertainty over the status of the transmission regulatory regime.

Finally, it is asserted that intrinsic characteristics specific to ElectraNet SA's network place it at greater risk. As a general comment, it should be recognised that, as the asset has recently changed hands, it might reasonably be expected that both general risks and risks specific to the business would have already been factored into the value of the business, balanced against the earnings expected under the established regulatory rate of return methodology.

For these reasons, the adoption of an asymmetric risk premium does not appear justified. It is also noted that an asymmetric risk premium was not applied in the recent Powerlink revenue cap determination.

As a further consideration, the impacts of any additional tax benefits available through accelerated depreciation for applicable assets following measures announced in the recent Commonwealth budget should also be considered. To the extent these measures are applicable to transmission assets, they could carry implications for the level of regulated return.

Opening Asset Base

In the calculation of the opening asset base, the application proposes to readmit previously optimised assets (to the value of $13m) at 1 July 2001 in calculating the rolled forward asset value at 1 January 2003. This would appear to amount to the re-optimisation of assets during the previous regulatory period, to which depreciation and other adjustments are subsequently applied for the remainder of the period. If this is the case, the extent to which this retrospectivity is consistent with the regulatory framework and requirements of the Code should be questioned.

In this respect, it is noted that the application makes allowance only for the readmission of previously excluded assets, but makes no adjustment for downward optimisation of redundant or under-utilised assets from the asset base. This is a matter on which the ACCC will presumably adjudicate, together with the reasonable value of new assets brought into service since the last reset.

The application also proposes to retrospectively include alleged 'material omissions' from the previous jurisdictional asset valuation, namely financing costs (interest during construction) and easements. At the outset, the extent to which retrospective adjustment is permissible under the Code is questioned.

As to the basis of any adjustment, it is noted that clause 6.2.3(d)(4)(iii) of the NEC concerning the regulation of transmission network revenues refers to the valuation of sunk assets in existence and generally in service on 1 July 1999 "at the value determined by the Jurisdictional Regulator", while clause 6.2.3(d)(4)(iv) refers to "subsequent revaluation of assets existing and in service on 1 July 1999 on a basis determined by the ACCC".

In commenting on the ACCC's discretion to amend the jurisdictional asset valuation, the application quotes detailed legal advice which suggests that the ACCC has discretion to make adjustments to the jurisdictional valuation to remedy material anomalies.

On the basis of the above, it would therefore appear to be entirely at the discretion of the ACCC as to whether the alleged omissions are included, based on changed circumstances or other considerations. As above, presumably any adjustments to the asset base that are found to be justified would be applied only on a forward-looking basis in the next regulatory period, and would not seek to unwind or retrospectively alter the initial jurisdictional valuation from a past date.

In terms of financing costs, the application proposes that an allowance of $44.6m should be applied (from 1 July 1998) to represent past interest costs during construction. This figure is based on an interest rate of 7.5% applied to the entire asset base, with the exception of the SA-Vic interconnection assets (on which such an allowance was previously applied).

Accepting the validity of financing costs in concept, there may be an argument for such an allowance to apply to new assets in the forthcoming regulatory period to provide for a reasonable return, and provide incentive for efficient investment. However, it is unclear why this allowance should be applied historically to the entire asset base on any reasonable basis. The logic of applying an allowance for financing costs to the full range of investments (nearly a quarter of which were undertaken over 40 years ago, as the submission states) is therefore highly questionable.

In relation to easements, a value of $215m (as revised in the supplementary application dated 9 May 2002) is put forward for inclusion in the opening asset base, comprising easement establishment costs of $104.3m and compensation costs of $111.0m. In comparison, a total value of some $3.1m was ascribed to easements in the existing jurisdictional asset base.

Easement establishment costs of $104.3m (revised from $123.0m proposed in the original application) are valued on a 'replacement cost' basis. However, the application notes that easements are generally granted in perpetuity. The relevance of a 'replacement cost' measure is therefore questioned. Clearly the assets in question do not require replacement, and the applicable costs are effectively sunk.

Establishment costs are stated to include activities such as route selection, environmental impact assessments, public consultation, surveys, cultural heritage and native title assessments and legal and registration costs. However, recognising that nearly half of the existing assets were established over 30 years ago (and nearly a quarter were established over 40 year ago) the relevance of many of these costs at that time is debateable. The accuracy and basis of this estimate as a measure of historical cost is therefore questioned.

Easement compensation costs are estimated (by proxy) at $111.0m. However, there appear to be inconsistencies in the calculation of this estimate based on the valuations quoted. A 30 June 2000 valuation places the total easement value at $153.4m (equivalent to $148.7m at 1 July 1999). A 2002 valuation places easement establishment costs at $111.5m (equivalent to $104.3m rolled back to 1 July 1999). This appears to imply a compensation cost estimate (ie the difference between the two figures) in the order of $44m. However, a compensation cost estimate of $111.0m is put forward. It is unclear how this estimate has been derived. In addition, no evidence of historic compensation costs has been presented.

Leaving aside these questions, should there be considered to be a valid argument for including estimated sunk costs such as easement acquisition and replacement costs incurred throughout the history of the establishment of the transmission network in the asset base, appropriate allowance should be made for depreciation. Given the age profile of ElectraNet SA's assets, it would appear that these historic costs should have been largely written down in the asset base in any case, with only the residual value relevant for future considerations. Appropriate deductions should also be made for shared easements and any offsetting unregulated revenue which may be earned through use of the easement rights.

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It is also noted that the easement valuation figure of $215m appears high relative to valuations applied to significantly larger networks interstate, namely Powerlink ($114m), TransGrid ($321m) and SPI Powernet ($232m).

As a general comment, it is noted that the new owners of the ElectraNet SA assets would have factored an assessment of fair market value into the purchase price of the assets, taking into account the regulatory earning capacity of the asset based on the prevailing regulatory methodology. As such, it might be expected that a reasonable assessment was made of what was likely to be included as regulated asset value based on a knowledge of the risks involved.

Accordingly, it could be argued that the established asset base and its earning capacity has already been reflected in the purchase price of the business, absorbing any historical omissions of asset value. Any step increase in the historic costs included in the asset base would essentially amount to a windfall gain for the shareholder. This would also run the risk of rewarding the purchaser for any over valuation of the asset. It is noted also that the jurisdictional letter cited as evidence of the material omissions from the asset base (dated 10 August 2001) post-dates the sale of the business.

As these costs effectively appear to be sunk, there appears to be little basis for their inclusion in the asset base. On balance, it would appear that significant weight should be attached to the original jurisdictional valuation.

Capital Expenditure

The application proposes a significant increase in the level of capital investment over the regulatory period, with projected expenditure totalling $409m. The capital investment program is stated to comprise over 100 individual projects in both regional and metropolitan areas of the network. This equates to an average annual project expenditure of over $80m, noting that minimal expenditure is expected during the initial six-month transition period.

This program is particularly aggressive given project investment levels in recent years, and in fact equates in value to around 60% of the initial asset base. While the cost increase of the proposed investment program on the average South Australian end user is quoted at 40 cents per week, it is noted that this alone would equate to a total increase of around 3% in annual electricity charges. Cost increases for large customers (particularly direct connect customers) would be correspondingly greater, all other things being equal.

A number of arguments are put forward to justify this increase.

At the outset, it is asserted that significant additional transmission investment is warranted by the lower pool price and reliability benefits this will provide, with flow on benefits to the economy. It is also asserted that significant network investment is necessary to relieve network constraints to prevent constrained access to the grid and corresponding wholesale price spikes. However, little evidence has been provided to support these claims.

It is noted that recent regional boundary analysis undertaken by NEMMCO has identified few network constraints in the SA region, and has in fact proposed only one change to the regional boundary structure in SA to this end, namely the creation of an East SA region reflecting the presence of an intra-regional network constraint at Tailem Bend (to apply from 1 June 2004). No other constraints impacting on SA were identified as warranting regional boundary change in this timeframe.

Similarly, pool price separation between South Australia and Victoria has declined dramatically in recent years, as illustrated in downward trend of the value of inward settlements residues, with auction proceeds falling from $36m for the six months to June 2000 to $11m for the six months to June 2002. Likewise, the average monthly spot price differential between South Australia and Victoria fell from 63% in January 2000 to just 4% in January 2002.[1]

The detailed methodology adopted in the application applies a probabilistic approach to a number of feasible transmission scenarios to derive a weighted average transmission investment requirement. However, little detail has been provided on the specific projects that are required to be undertaken, even though the application states that a number of these are common to many scenarios. The probability applied to specific scenarios is also unclear, and it is therefore not possible to confirm the validity of the assumptions adopted. It is also unclear therefore whether extreme scenarios may be disproportionately impacting on the projected requirements, given the weighted average approach.

It is assumed that a significant proportion of the proposed expenditure would comprise projects which would be required to undergo the applicable planning and consultation processes to qualify for regulatory status, under the recently approved network and distributed resources Code changes. As the designated planning body in SA (and registered TNSP for this purpose) it is expected that the Electricity Supply Industry Planning Council (ESIPC) would play a primary role in this regard.

The pro-active and consultative approach adopted by the ESIPC in evaluating future network development requirements (such as the current review of future network development needs in the State's South East) is supported, and enhances transparency in forward transmission planning. Independent planning is a key feature of the transmission regulatory framework in South Australia, and should be linked more closely to the transmission revenue setting process. It is also noted that an avenue of appeal to the ACCC would apply for (non-reliability) projects exceeding $10m in value, should any unresolved disputes arise through consultation.

However, it is not clear from the expenditure projections proposed that sufficient allowance has been made for these planning processes to occur, noting that consultation has yet to commence on a single new large augmentation project at this time, with the possible exception of the proposed SA-Vic interconnect regulated augmentation and ESIPC consultation on network

[1] *Settlement Residue Auctions and Network Rebates*, SAIIR, 2002

development options in the South East. The linkage with these planning processes also remains unclear.

There would be an expectation under the Code that alternatives to transmission augmentation would be considered, including distribution augmentation, generation and demand side measures. It is also conceivable that unregulated alternatives may emerge to address specific augmentation needs. This is potentially significant, given that a single project such as the SA-Victoria interconnect upgrade, should it proceed on an unregulated basis, would remove the requirement for approximately $50m of works from ElectraNet SA's forward capital project schedule. However, it is unclear from the projections that allowance has been made for these alternatives, which should not be pre-empted. On the surface, it appears that all network needs are assumed to satisfy the regulatory test and proceed as regulated transmission developments.

The level of investment is proposed, in part, to accommodate a range of new generation development proposals, including wind farms. Consistent with conservative planning assumptions, it would appear appropriate for assumptions on the level of expected generation investment to be based closely on the level of underlying demand growth as the ultimate driver of network investment. Any projected network developments that depart significantly from underlying demand growth should therefore be closely scrutinised.

The application notes that "South Australia is on the verge of developing a major wind generation industry" (p3.2). The ElectraNet SA publication, "A Transmission Network To Power South Australia", released in February 2002, lists some thirteen proposed wind farm developments in South Australia, of which four are recorded as committed.

Only three of these projects are known to have applied for or obtained a transmission licence at the present time. Given the nature of market-driven generation investment, it might be expected that only a given portion of mooted generation developments will ultimately prove to be viable in practice. A balanced view of likely generation developments clearly needs to be taken in assessing reasonable transmission requirements, recognising the level of potential generation investment that will actually reach the market over the regulatory period.

It will also be important to compare the bottom-up demand forecasts developed by ElectraNet SA with the revised load forecasts to be published in NEMMCO's 2002 Statement of Opportunities (due by end July 2002). This would provide a useful cross check, and might also alter the probabilistic demand scenarios modelled.

While a probabilistic approach may represent an appropriate basis for long-term network planning, it would expected that more specific project information would be available over the immediate investment horizon, particularly over the forthcoming regulatory period. Without any information on the specific investments that are proposed, it is difficult to see how the substantial investment program that has been put forward can be reasonably justified and approved. It is also noted that no supporting information has been provided to explain the capital expenditure breakdown into the categories of "lines", "substations" and "other".

South Australian network users are entitled to expect information on the range of network projects envisaged and the benefits these are expected to deliver, before being asked to bear the corresponding increase in costs to fund the investment program. This will promote understanding and appreciation of the need for and details of the developments proposed, in the interests of an open and transparent revenue setting process.

It should be possible to explicitly identify and provide some level of justification for the majority of anticipated project expenditure, with the balance to provide for unforseen projects which emerge during the regulatory period. Given the size of the investment program proposed, it might be expected that a significant number of projects would be at an advanced state of development, for which details should therefore be available. This information should form the basis of a detailed transmission investment schedule for the regulatory period to increase accountability to network users.

In the absence of significant increases in underlying peak demand levels or a demonstrable deterioration in network performance levels, the need for what amounts to a massive investment program remains unclear. Consequently, the proposed level of investment represents a largely unsubstantiated capital projects plan, without supporting detail on the individual projects required. Unless specific projects can be identified which are reasonably expected to satisfy the regulatory test in time for construction to occur during the regulatory period, there appears to be little justification to approve a large unallocated capital expenditure allowance for probable and speculative projects. It should also be recognised that an overly optimistic capital investment program will only increase the risk of early asset optimisation at the next reset.

Depreciation

It is noted that provision has been made in the regulatory framework for accelerated depreciation for assets at risk. This risk might arise due to factors such as reductions in service level and stranded asset bypass. Under these arrangements, it is understood that the TNSP can identify assets at risk of stranding in advance and seek accelerated depreciation to apply during the forthcoming regulatory period. However, in the event that bypass does occur, no additional adjustment is available after the fact to compensate for the foregone revenue. It is therefore important that the TNSP utilise this tool in advance to manage its risk.

While the application quotes a technological change risk as high as 10% (ie $90m), no claim for accelerated depreciation has been made. It is therefore assumed that any risk which eventuates during the regulatory period will be reflected in optimisation of the assets at the next reset, given that allowance for accelerated depreciation is available only on a forward looking basis.

While such risk factors may be difficult to estimate and provision for in advance, it would not be reasonable to simply allow for a compensating adjustment at the end of the regulatory period for any risks that do arise during the period, in preference to the use of accelerated depreciation in advance. To apply such an automatic allowance would be to place these risks with the network user. Clearly the TNSP has greater knowledge and ability to control, influence and mitigate against such factors as asset stranding and technological obsolescence than the network user, and therefore these risks properly remain with the TNSP.

The level of expected depreciation is predicated on the opening asset base and level of asset additions proposed. As noted above, a number of assumptions underpinning these proposed levels are open to question, and consequently will influence the level of allowable depreciation, as will the level of asset optimisation applied. It might also be expected that the number of assets which are claimed to be at the end of their economic lives would correspondingly reduce the overall level of depreciation.

Operating and Maintenance Expenditure

Whilst comparisons are made in the application between historic levels of capital expenditure and recent trends, it might be considered that network reliability and performance is the better indicator of appropriate investment levels. To assume that a return to historic investment levels represents an efficient investment level not only assumes that such levels were correct in the first place, but also assumes that future conditions (such as rates of growth etc) are the same as those that applied at the time such investments were made. Simple comparisons of capital expenditure and demand growth alone are of limited value unless such factors are taken into account.

Historical expenditure patterns also pre-date the NEM and the commercial regulatory environment in which TNSPs currently operate. As demonstrated in the generation sector, it might be expected that the greater commercial drivers in this environment lead to the realisation that electricity asset utilisation and performance can be improved significantly over historical performance levels, and asset lives can be extended far beyond original engineering expectations.

For these reasons, asset life alone can not be taken as a reliable indicator of the need for asset replacement, and greater emphasis should be placed on network performance over time. Given that the developmental phase of the transmission network occurred 30 to 50 years ago, it is not unexpected that a large proportion of the existing assets increasingly fall into older age categories (ie 40 years plus and 30 years plus) over time. It would be surprising if this experience differed substantially across TNSPs in the NEM.

However, unless this ageing asset profile can be linked to deteriorating performance levels, it is not clear that all aged assets automatically require replacement. The aim should be to replace worn assets, not depreciated assets. Experience in the market to date has shown that there is significant scope to challenge traditional assumptions over effective asset lives and performance levels. Only limited evidence has been presented to suggest that network performance and reliability levels have deteriorated significantly or are reasonably expected to do so in the near future, to justify the level of capital expenditure proposed.

NRG Flinders therefore supports the increasing emphasis placed on detection and monitoring equipment. This represents a practical and preventative maintenance strategy aimed at significantly reducing the need for automatic asset replacement and refurbishment, and complements the (n-x) asset design philosophy (ie built in redundancy to cater for contingencies). Targeting individual components for replacement rather than complete assets is also supported as a cost effective maintenance practice.

A number of favourable cost comparisons and benchmarking results quoted in the application indicate that ElectraNet SA performs well in terms of its recent cost performance. It would be disappointing to see this performance eroded through substantial increases in expenditure. Consequently, continuous improvement dictates that ongoing efficiency and productivity gains are essential to remain competitive, and should be reflected in the level of allowable operating and maintenance expenditure.

The inclusion of anticipated grid support costs as an allowance in the opex budget is supported. In the South Australian setting, such costs could be argued as reasonably foreseeable, given the lack of widespread network constraints in SA (in contrast to Qld). Conversely, there would appear to be limited argument for a pass through provision to cover such expenses. It would also appear that the associated costs, risks and performance characteristics of these services can be effectively managed by the TNSP through appropriate contractual provisions. As noted in the application, ElectraNet SA has an established record of efficiently managing the delivery of services under contract, including the use of incentive based provisions.

A range of proposed cost pass through categories are proposed in the application, with the process to manage pass through events to be discussed with the ACCC. Events types include grid support costs (discussed above), NEM changes such as firmer access, tax changes, catastrophic events and regulatory changes.

In terms of possible NEM changes, it might be expected that firmer access arrangements would be accompanied by market based income sources, possibly offsetting the level of regulated revenue required. It is therefore conceivable that these events could result in a negative pass through to network users.

Catastrophic events are presumably limited to those completely outside the control or influence of the TNSP (ie in the nature of Force Majeure events) and would not include risks against which appropriate insurance and other mitigation strategies should be available. The level of insurance cover in place is not itself the relevant factor for consideration.

Pass through in relation to regulatory risks would presumably apply only in the most limited circumstances where demonstrable cost impacts result. To allow a blanket pass through for such events would also represent double dipping in any event, noting that the application elsewhere proposes an asymmetric risk premium in the rate of return to compensate the TNSP for such risks (discussed above).

It is noted that the proposed opex levels (amounting to $429.3m over the regulatory period) correspond to the proposed asset base, discussed above, and will therefore depend on the final asset base approved. It might also be expected that the addition of new assets to the asset base will not create a need for additional maintenance expenditure to the same level that would be required in the case of older existing assets.

Total Revenue

In the calculation of total revenue, the application again notes those events for which it is proposed that pass through provisions would apply, and provides a summary of the applicable cost elements. Comments have been made above on a range of these issues.

The application disputes the established methodology adopted by the ACCC for the inclusion of new assets into the regulated asset base on cash flow grounds, and proposes an alternative methodology. While it is claimed the method proposed produces the same result in NPV terms, it is considered that further justification is warranted before departing from the consistent approach the ACCC has applied to date, and to ensure no adverse revenue timing effects will impact upon network users.

It is unclear that the increase in capital spend proposed can be easily accommodated within the maximum annual tariff increase limits applied under the Code. This factor should be considered in reviewing the revenue requirement proposed. It should also be recognised that the level of rebate applied to network tariffs through the proceeds of settlements residue auctions has declined substantially in recent years with the decline in inward settlement residues into South Australia. Consequently, the effect of any increase in tariff levels on end users will be greater.

As noted in the application, transmission costs are relatively high in South Australia, but compare more favourably with interstate cost levels when considering the unique characteristics of the State's network. There is a risk that the overall level of revenue and cost increases proposed will jeopardise the comparatively favourable transmission cost levels in South Australia, and result in a further escalation of real costs.

Clearly, there is a need for balance between improved reliability and cost, recognising the inherent trade off. However, the application focuses almost exclusively on reliability, at the expense of cost efficiency and value for money considerations.

In this regard it is also noted that, in considering South Australia's arrangements for transmission revenues and pricing, the ACCC in its final determination[2] authorising the Code changes which gave effect to derogation authorising these arrangements noted arguments raised by interested parties "…regarding the valuations given to revenue cap parameters and the risk that without being subject (to) independent review or matched against national benchmarks they may result in over generous valuations. Although these criticisms are valid, the arrangements are transitional, and the Commission will address these issues when it assumes the function of setting transmission revenues from 1 January 2003".

[2] *Final Determination: Applications For Authorisation: National Electricity Code*, 22 December 1999, ACCC.

The application states that some 97% of revenue is derived from regulated sources, with the remainder sourced from non-regulated activities. The ACCC should convince itself that cost reflective charging has been adopted for competitive activities and that overheads have been appropriately apportioned to respective activities, to ensure that there is no cross subsidisation of competitive activities by users of regulated network services.

In general, it is considered that any increase in revenue should be directly linked to the level of market risk the TNSP is prepared to accept, as explored below. It is also considered that new network developments should increasingly be linked to the delivery of firm network access over time.

Service Standards

In the setting of network service standards, the application reflects the principle that the TNSP should be held to account for factors that are within its control only.

Whilst NRG Flinders would agree that risks should be allocated to the party best able to manage them, this may not necessarily dictate that all risks such as storms and other natural events should be passed on to network users. While weather events themselves are clearly outside the control of the TNSP, the TNSP is able to take account of these factors in network design and operation, and through investment in protective measures and equipment to safeguard the network from such risks, and other mitigating strategies.

While the degree of influence and control may be limited in some instances, the TNSP will clearly be in a better position to design and manage the network to account for such risks than the network user. For this reason it would be unreasonable to pass such risks on to end users. The factor itself does not need to be in the control of the TNSP for the level of risk to be influenced by TNSP behaviour.

The management of the SA-Victoria interconnect might be considered a prime example. While weather events can not be controlled directly by the TNSP, the level of de-rating undertaken to manage the impact of such risks on network operation is clearly within the control of the TNSP.

It is noted that transmission service standards are presently under review by the ACCC. Pursuant to this review, it is understood that a final consultant report is to be released in June 2002, before guidelines are then developed and implemented by the ACCC. It is presumed that appropriate allowance will be made in the revenue determination to allow these measures and incentives to be incorporated into the revenue base of ElectraNet SA, without the need for any subsequent pass through adjustment. Should the service standards review not conclude in advance of the revenue determination, the current performance incentive scheme applied to ElectraNet SA should be continued in the interim to preserve incentives for network performance.

NRG Flinders supports the development of service standards and associated financial performance incentives linked to measures which capture the market impact of transmission operations. The need for such incentives is exemplified by the timing impact of maintenance outages. Such measures should be driven primarily driven by the needs of the market and not by what may or may not be achievable within certain timeframes and operating parameters, although such factors do need to be recognised in framing appropriate performance targets.

In the short-term, NRG Flinders would advocate the adoption of a multi-dimensional weighted basket of performance measures to capture the existing suite of traditional output based indicators. This approach overcomes the impact that one-off events may have on individual measures, such as minutes of lost supply. However, it is considered that all interruptions which impact on the continuity of customer supply should be recorded in some manner, regardless of duration. Outage frequency measures will therefore remain an important element. There is also scope to include within these aggregate measures a category that records all outages, both planned and unplanned, as a measure of total network availability.

The adoption of exit point reliability indices is supported. To better gauge the impact of outages on end users, a peak/off peak break down might also be considered. However, it should be recognised that the SA Transmission Code is only one component of the overall service standards framework. As noted above, measures that more accurately reflect the market impact of transmission operations should also be applied in the forthcoming regulatory period. A measure of interconnect performance such as the Available Capacity Factor (ACF), as previously proposed by ElectraNet SA[3], might be one such indicator. Other incentives to minimise the market impact of transmission outages are strongly supported.

In the longer term, there are strong arguments for deriving an increasing share of transmission revenue from market-based sources, and thereby placing a greater share of the TNSPs revenue base at risk based on commercial performance. These income streams could be used to progressively reduce regulated revenue sources. This presents significant upside earning potential for the TNSP, in return for bearing an increasing share of market risk which incentivises more efficient performance. Increases in revenue are linked directly to the level of market risk the TNSP is prepared to accept.

Initial applications might include measures to increase the firmness of settlement residues, potentially by exposing the TNSP to a portion of the residues derived. Appropriate measures would need to be applied to avoid perverse incentives (eg the TNSP could underwrite the firm settlement residue component across a given interconnect and in return receive a share of the marginal non-firm flows). These revenue sources could be offset by corresponding reductions in regulated TUOS levels. Nevertheless, a significant step increase in the level of earnings at risk would need to occur before an increase in the level of WACC could be justified.

Measures such as these are considered highly desirable and support a move towards increasing firmness of transmission access and accountability for performance in the delivery of network services to the market.

[3] *ElectraNet SA, submission to the State Government Electricity Taskforce*, 2001

CONCLUSIONS

Overall, the application represents a substantial departure from historical expenditure and revenue levels, and a number of detailed aspects warrant careful consideration.

Several components of the proposed cost of capital should be questioned, including the proposed risk free rate of return, the use of a small firm risk premium, and the adoption of an asymmetric risk premium.

The inclusion of transmission easement costs and financing costs into the historical asset base as 'material omissions' from the jurisdictional valuation should be questioned, given the ACCC's discretion in this regard. The logic of applying a historical allowance of some $44m for financing costs across the entire asset base is questionable, and estimates of historic easement costs appear to be lacking in rigour and justification.

The proposed capital investment program of $409m represents a largely unsubstantiated capital projects budget, lacking in any specific detail on individual projects. In the absence of significant increases in underlying demand levels or a demonstrable deterioration in network performance, the need for what amounts to a massive investment program remains unclear.

Further substantiation and project information needs to be provided in the form of a forward project schedule to justify a capital budget of this magnitude, and projected developments which depart significantly from the underlying level of demand growth should be critically assessed. The purported benefits from additional network investment, namely alleviation of network constraints and pool price benefits, also appear to be largely unsubstantiated without project information.

Provision for accelerated depreciation of assets at risk is a tool that has been made available to manage risks such as network bypass. Clearly such a tool is only intended to apply in advance, and no subsequent adjustments should be made at the end of the regulatory period to compensate for risks which do eventuate, as this would effectively relieve the TNSP of this risk.

The increased use of monitoring and early warning detection equipment coupled with a remedial asset replacement approach is supported, in preference to the automatic replacement of depreciated assets in strict engineering timeframes. Network reliability and performance is considered a better indicator of the need for asset investment than historical investment levels and asset age profiles, given the degree to which asset lives and performance levels have improved in the market environment over traditional expectations.

NRG Flinders supports the development of service standards and associated financial performance incentives linked to measures which capture the market impact of transmission operations, driven by the needs of the market. Such measures should be applied in the forthcoming regulatory period.

In the longer term, there are strong arguments for deriving an increasing share of transmission revenue from market-based sources, thereby placing a greater share of the TNSPs revenue base at risk based on commercial performance to support firmer transmission access and firm inter-regional hedging.

NRG Flinders is grateful for this opportunity to provide input into the South Australian transmission revenue cap determination process, and looks forward to further opportunities to comment.

Should you have any queries, please feel free to contact Simon Appleby on (08) 8372 8706 or myself on (08) 8372 8726.

Yours sincerely

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