Review of re-valuation versus roll-forward

Australian Competition and Consumer Commission

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1. Introduction

1.1 Introduction

Sinclair Knight Merz Pty Ltd have been engaged by the Australian Competition and Consumer Commission (ACCC or Commission), to develop a paper on Sinclair Knight Merz's opinion on the merits of periodic revaluations or rolling forward of the asset value of Australian electricity transmission systems under the regulatory jurisdiction of the Commission.

In developing this paper, Sinclair Knight Merz has applied its technical and economic knowledge of the Australian electricity transmission industry, the assets involved, the National Electricity Code, the deprival valuation and ODRC valuation methodologies, and other relevant documents and institutions that we are aware of for the industry. This paper does not purport to be a legal or accounting opinion on the way the Commission should proceed.

1.2 Background & scope

In May 1999 the ACCC released its draft Statement of Regulatory Principles for the Regulation of Transmission Revenues (DRP). The ACCC is in the process of finalising the statement.

The DRP explains the ACCC's approach to setting CPI - X revenue caps for regulated electricity transmission services. The DRP adopts an approach of setting CPI - X caps for five-year periods. . The relevant parameters are based on expected efficient costs, including expected O&M's, capex, depreciation etc. The service provider's asset base is one of the inputs into the ACCC's determination.

The DRP proposes using the optimised depreciated replacement cost (ODRC) approach in order to determine the asset rate base. The context for this approach was the transition to the new regulatory framework as outlined in the National Electricity Code. Since then the approach has been applied in a number of decisions including the ACCC's revenue cap decisions applying to Transgrid and Powerlink.

In finalising the DRP the ACCC needs to consider its approach in future reviews ie post the transition to the new regulatory framework. The ACCC is considering two options. The first is to revalue assets on a periodic basis (for example each five-year regulatory period) using the ODRC methodology. The second option being considered is based on the gas code. This approach initially uses the ODRC methodology to set the rate base. In subsequent regulatory periods the rate base is determined by adopting the initial ODRC valuation and adding in new investment at cost.

The National Electricity Code provides some guidance on how the ACCC should determine the asset rate base. It states that the ACCC must have regard to the 19 August 1994 COAG agreement that deprival value should be the preferred approach to determining the rate base. The Code defines deprival value as "a value ascribed to assets which is the lower of economic value or optimised depreciated replacement value" (Glossary, chapter 10). The DRP proposes use of ODRC valuations. It argues that this is consistent with the deprival value.

The aim of this consultancy project is to assess the relative merits of the two approaches to determining the asset rate base from an economic efficiency perspective. The project also aims to assess the consistency of the two approaches with the deprival value of the assets.

Specifically, Sinclair Knight Merz's terms of reference are to:

1. Assess the relative merits of determining the asset rate base of regulated electricity transmission assets by:
   (a) valuing all assets at Optimised Depreciated Replacement Cost (ODRC) on a periodic basis (for example at the beginning of each five year regulatory period); or
   (b) determining the rate base at the beginning of each (five year) regulatory period as the sum of the opening (ODRC based) valuation of assets in the first period (adjusted to take into account depreciation and other relevant factors) and the actual cost of new capital expenditure undertaken since then (also adjusted for depreciation and other relevant factors).

2. In assessing the relative merits have particular regard to the impact of the alternative approaches on:
   - incentives for the regulated service provider to carry out efficient investment;
   - incentives for the regulated service provider to improve efficiency in the provision of transmission services; and
   - the robustness, transparency and simplicity of the different approaches.

3. Assess the consistency of the two approaches with the deprival value of the assets.

1.3 The COAG agreement

The brief notes the COAG agreement.

The terms of the relevant agreement were[1]:

2. Consistent with the agreement at Council's February 1994 meeting that the principles relating to recovery of the fixed cost component of network pricing would encompass common asset valuation methodologies and rates of return as well as cost reflective and uniform pricing methodologies, agreed:-

(a) in relation to the fixed cost component of network pricing that:

[1] COAG meeting in Darwin 19 August 1994 from the Queensland Govertment's website at http://www.premiers.qld.gov.au/about/igr/communiques/cag19894.htm. The numbering of the last points has been amended. The NGMC work referred to in (b)(iii), if it was produced, has not been sighted.

(i) network prices should be determined according to a common method throughout the national electricity market;

(ii) network charges for EHV transmission networks and lower voltage sub-transmission networks should in principle be cost reflective ensuring that both franchised and non-franchised customers and generators are charged, on a consistent basis, in accord with their use of network assets, and taking into account the impact of network constraints;

(iii) in view of the complexity of calculating the value of network services used by individual small customers and householders, distribution system pricing could be calculated using a greater degree of averaging than that required for the EHV and sub-transmission networks;

(iv) further detailed work should be carried out by the NGMC to determine the extent of charges that should be applied to existing and new generators;

(v) further work should be carried out by the NGMC in conjunction with the development of the energy market to ensure appropriate treatment of interconnections including commercial incentives for the development of new interconnectors;

(vi) within distribution, the retail and network functions should be ringfenced and separately accounted for; and

(vii) prices for high voltage and distribution networks should be transparent and published;

(b) for the purposes of developing network pricing and access charges, the methodology for asset valuation should be consistent with the National Performance Monitoring sub-committee report and with Australian Accounting Standards, and:

(i) that Deprival Value should be adopted as the preferred approach to valuing network assets;

(ii) that the approaches adopted for applying Deprival Value should be transparent and uniform across jurisdictions to avoid distortions to competition; and

(iii) that by 31 December 1994 the NGMC establish a set of agreed transparent and non-discriminatory methods and principles for applying Deprival Value.

3. Code requirements

3.1 National Electricity Code

The relevant excerpts from the National Electricity Code provide, inter-alia:

6.2.3 Principles for regulation of transmission aggregate revenue

The regime under which the revenues of Transmission Network Owners and/or Transmission Network Service Providers (as appropriate) are to be regulated is to be administered by the ACCC from 1 July 1999 in accordance with the following principles:

...

(d) The regulatory regime to be administered by the ACCC must be consistent with the objectives outlined in clause 6.2.2 and must also have regard to the need to:

...

(4) provide a fair and reasonable risk-adjusted cash flow rate of return to Transmission Network Owners and/or Transmission Network Service Providers (as appropriate) on efficient investment given efficient operating and maintenance practices on the part of the Transmission Network Owners and/or Transmission Network Service Providers (as appropriate) where:

(i) assets created at any time under a take or pay contract are valued in a manner consistent with the provisions of that contract;

(ii) assets created at any time under a network augmentation determination made by NEMMCO under clause 5.6.5 are valued in a manner which is consistent with that determination;

(iii) subject to clauses 6.2.3(d)(4)(i) and (ii), assets (also known as "sunk assets") in existence and generally in service on 1 July 1999 are valued at the value determined by the Jurisdictional Regulator or consistent with the regulatory asset base established in the participating jurisdiction provided that the value of these existing assets must not exceed the deprival value of the assets and the ACCC may require the opening asset values to be independently verified through a process agreed to by the National Competition Commission;

(iv) subject to clauses 6.2.3(d)(4)(i) and (ii), valuation of assets brought into service after 1 July 1999 ("new assets"), any subsequent revaluation of any new assets and any subsequent revaluation of assets existing and generally in service on 1 July 1999 is to be undertaken on a basis to be determined by the ACCC and in determining the basis of asset valuation to be used, the ACCC must have regard to:

> A the agreement of the Council of Australian Governments of 19 August 1994, that deprival value should be the preferred approach to valuing network assets;
>
> B any subsequent decisions of the Council of Australian Governments; and
>
> C such other matters reasonably required to ensure consistency with the objectives specified in clause 6.2.2; and
>
> (v) benchmark returns to be established by the ACCC are to be consistent with the method of valuation of new assets and revaluation, if any, of existing assets and consistent with achievement of a commercial economic return on efficient investment;

A more complete extract is appended.

3.2 National Gas Code

The National Gas Code[2] explicitly provides for roll-forward of the asset base at the start of each regulatory period beyond the first.

> *8.9 Sections 8.15 to 8.29 then describe the principles to be applied in adjusting the value of the Capital Base over time as a result of additions to the Covered Pipeline and as a result of parts of the Covered Pipeline ceasing to be used for the delivery of Services. Consistently with those principles, the Capital Base at the commencement of each Access Arrangement Period after the first, for the Cost of Service methodology, is determined as:*
>
> *(a)the Capital Base at the start of the immediately preceding Access Arrangement Period; plus*
>
> *(b)the New Facilities Investment or Recoverable Portion (whichever is relevant)in the immediately preceding Access Arrangement Period (adjusted as relevant as a consequence of section 8.22 to allow for the differences between actual and forecast New Facilities Investment);less*
>
> *(c)Depreciation for the immediately preceding Access Arrangement Period; less*
>
> *(d)Redundant Capital identified prior to the commencement of that Access Arrangement Period,*
>
> *and for the IRR or NPV methodology, is determined as:*
>
> *(e)the Residual Value assumed in the previous Access Arrangement Period (adjusted as relevant as a consequence of section 8.22 to allow for the differences between actual and forecast New Facilities Investment);less*
>
> *(f)Redundant Capital identified prior to the commencement of that Access Arrangement Period, subject, irrespective of which methodology is applied, to such adjustment for inflation (if any) as is appropriate given the approach to inflation adopted pursuant to section 8.5A.*

[2] National Third Party Access Code for Natural Gas Pipeline Systems

...

Initial Capital Base -After the Expiry of an Access Arrangement

8.14 Where an Access Arrangement has expired, the initial Capital Base at the time a new Access Arrangement is approved is the Capital Base applying at the expiry of the previous Access Arrangement adjusted to account for the New Facilities Investment or the Recoverable Portion (whichever is relevant),Depreciation and Redundant Capital (as described in section 8.9)as if the previous Access Arrangement had remained in force.

New Facilities Investment

8.15 The Capital Base for a Covered Pipeline may be increased from the commencement of a new Access Arrangement Period to recognise additional capital costs incurred in constructing New Facilities for the purpose of providing Services.

8.16 The amount by which the Capital Base may be increased is the amount of the actual capital cost incurred (New Facilities Investment) provided that:

(a) that amount does not exceed the amount that would be invested by a prudent Service Provider acting efficiently, in accordance with accepted good industry practice, and to achieve the lowest sustainable cost of delivering Services; and

(b) one of the following conditions is satisfied:

(i)the Anticipated Incremental Revenue generated by the New Facility exceeds the New Facilities Investment; or

(ii) the Service Provider and/or Users satisfy the Relevant Regulator that the New Facility has system-wide benefits that, in the Relevant Regulator's opinion, justify the approval of a higher Reference Tariff for all Users; or

(iii) the New Facility is necessary to maintain the safety, integrity or Contracted Capacity of Services.

8.17 For the purposes of administering section 8.16(a),the Relevant Regulator must consider:

(a)whether the New Facility exhibits economies of scale or scope and the increments in which Capacity can be added; and

(b)whether the lowest sustainable cost of delivering Services over a reasonable time frame may require the installation of a New Facility with Capacity sufficient to meet forecast sales of Services over that time frame.

8.18 Reference Tariff Policy may, at the discretion of the Service Provider, state that the Service Provider will undertake New Facilities Investment that does not satisfy the requirements of section 8.16.If the Service Provider incurs such New Facilities Investment, the Capital Base may be increased by that part of the New Facilities Investment which does satisfy section 8.16 (the Recoverable Portion).

8.19 The Reference Tariff Policy may also provide that an amount in respect of the balance of the New Facilities Investment may subsequently be added to the Capital Base if at any time the type and volume of services provided using the increase in Capacity attributable to the New Facility change such that any part of the Speculative Investment Fund (as defined below) would then satisfy the requirements of section 8.16.The amount of the Speculative Investment Fund at any time is equal to:

(a)the difference between the New Facilities Investment and the Recoverable Portion, less any amount the Service Provider notifies the Relevant Regulator (at the time the expenditure is incurred)that it has elected to recover through a Surcharge under section 8.25 (Speculative Investment);plus

(b)an annual increase in that amount calculated on a compounded basis at a rate of return approved by the Relevant Regulator which rate of return may, but need not, be different from the rate of return implied in the Reference Tariff; less

(c)any part of the Speculative Investment Fund previously added to the Capital Base under this section 8.19.

Forecast Capital Expenditure

8.20 Consistent with the methodologies described in section 8.4,Reference Tariffs may be determined on the basis of New Facilities Investment that is forecast to occur within the Access Arrangement Period provided that the New Facilities Investment is reasonably expected to pass the requirements in section 8.16 when the New Facilities Investment is forecast to occur.

8.21 If the Relevant Regulator agrees to Reference Tariffs being determined on the basis of forecast New Facilities Investment, this need not (at the discretion of the Relevant Regulator) imply that such New Facilities Investment will meet the requirements of Section 8.16 when the Relevant Regulator considers revisions to an Access Arrangement submitted by a Service Provider. However, the Relevant Regulator may, at its discretion, agree (on written application by the Service Provider) at the time at which the New Facilities Investment takes place that it meets the requirements of section 8.16,the effect of which is to bind the Relevant Regulator's decision when the Relevant Regulator considers revisions to an Access Arrangement submitted by the Service Provider. For the purposes of public consultation, any such application must be treated as if it were a proposed revision to the Access Arrangement submitted under section 2.28.

8.22 For the purposes of calculating the Capital Base at the commencement of the subsequent Access Arrangement Period, either the Reference Tariff Policy should describe or the Relevant Regulator shall determine when the Relevant Regulator considers revisions to an Access Arrangement submitted by a Service Provider, how the New Facilities Investment is to be determined for the purposes of section 8.9.This includes whether (and how) the Capital Base at the commencement of the next Access Arrangement Period should be adjusted if the actual New Facilities Investment is different from the forecast New Facilities Investment (with this decision to be designed to best meet the objectives in section 8.1).

It should be noted that with respect to valuation methodologies (generally in the case of the NEC and for the initial capital base in the case of the National Gas Code), the NEC has a stated preference for a particular valuation method (deprival value) whereas the National Gas Code provides that a number of factors should be considered by the Regulator but the value ascribed should not normally be outside the range of depreciated historic cost to ODRC – commonly a very wide range.

Given the wide range of values (valuation factors) provided for by the National Gas Code for the Regulator's consideration and discretion, if the National Gas Code had provided for a periodic re-valuation of the assets then it would have been very difficult to maintain consistent judgement and discretionary balance between the various factors over the very long term.

Nevertheless, there is no direct mechanism in the National Gas Code beyond the initial valuation benchmarking the carrying value against an economic measure (although it is not explicitly excluded from being applied via the depreciation schedule).

3.3 The principle of the Deprival Value methodology

> *Deprival Value determines the "value to the network business" of each asset by estimating the minimum loss that the business would incur if it was deprived of the asset. For example, if an asset can and should be replaced, then the loss is the current cost of replacing it with an asset which provides the most efficient means of meeting present and reasonable expected future requirements. If the greatest amount that can be recovered from that asset, either through its continued use or through its disposal, is less than the replacement cost, then this lower value (the asset's economic value) represents the loss to the business.*
>
> *Thus Deprival Value is the lower of the optimised replacement cost of an asset and its economic value to the business. Under the Deprival Value method, assets are valued at replacement cost and then adjusted for any over-capacity and lower consumer value.*[3]

Deprival valuation intrinsically requires optimisation (as an entity that were deprived of an asset and who chose to replace the functionality would logically optimise the replacement). Optimised Deprival Value (ODV) and Deprival Value (DV) are thus the same concept.

Whilst a definition of the above form is the 'model' for the deprival valuation method, the NEC provides a specific formula (in the Glossary) for the manner of calculation of the deprival value as the minimum of the ODRC value and the economic value. The COAG agreement of 19 August 1994 did not, on the face of it, limit the definition of the term 'deprival value' by a formulaic definition.

[3] http://www.accc.gov.au/sched/sched120.htm

The economic value is taken to be the maximum of the scrap value and the NPV of future expected cashflows to be derived from the asset. Where these future cashflows are wholly dependent on the valuation process (ie they are wholly created from the asset valuation via the building block approach), then this is circular and the DV reduces to the ODRC. If there is some external cap on tariffs however (eg in jurisdictional legislation) then an economic value test based on the capped tariffs should be considered.

Notwithstanding the formula in the NEC Glossary, it is considered appropriate to maintain a view of the broader model above as to what is meant by a deprival value.

In the absence of external factors the deprival value reduces to the ODRC. The ODRC value has been calculated as the basis for the initial asset valuations in relevant recent electricity transmission initial capital bases (Queensland[4] and NSW/ACT[5] for example).

If the industry were deprived of a major transmission asset then given the 'essential service' nature of electricity transmission, the inability of upstream and downstream system users to practically relocate, or do without, or substitute for grid electricity, there would be little doubt that the economic value would be higher than the optimised replacement cost and that the asset would in fact be replaced in an optimised form at that time. Any external economic constraint such as a tariff cap that would otherwise preclude such a replacement of the asset would be expected to be removed in such a deprival scenario.

Hence it is considered that ODRC valuation is a practical proxy for deprival value for use in the NEM where deprival value is called for. The valuer should nevertheless be alert to any potential factor that might become relevant at some future stage that might justify a lower value than the ODRC value under the economic value element of deprival value.

[4] Decision: "Queensland Transmission Network Revenue Cap 2002-2006/07" ACCC 1 November 2001

[5] Decision: "NSW and ACT Transmission Network Revenue Caps 1999/00-2003/04" ACCC 25 January 2000

4. Factors affecting an asset valuation

4.1 Introduction

An asset valuation utilising the deprival/ODRC valuation technique is subject to change over time due to factors such as technology advancement that the theoretical new asset might incorporate, and also changes in the cost of the elements making up the replacement asset. This section reviews these sources of uncertainty and puts them into the context of a typical electricity transmission asset.

If the deprival value of an asset were expected to be consistently the same as the valuation that would be provided by rolling forward the asset value, except for immaterial changes, then the methodology with the lowest calculation cost and transparency would, and should, be immediately selected. If accounting systems are set up to appropriately track the asset register then the rolling forward method has lower calculation costs and more transparency than re-valuation.

The rate at which a rolled-forward asset value might diverge from a theoretically continuously calculated deprival value is thus important in:

- deciding whether on-going rolling-forward is economically efficient,
- determining the frequency of re-valuations appropriate to maintain the expected difference between the carrying value of the asset and the deprival value to an acceptable level if periodic revaluations are selected

4.2 Rate of technological change

The rate of technological change in an industry is a factor in the rate at which the above divergence might proceed. The technological change rate is highly specific to the industry under consideration and the high voltage transmission industry is highly specialised. Regulators making decisions about appropriate revaluation frequencies require industry advice regarding these technological change rate factors.

A review of technological change factors applicable in the electricity transmission industry from Sinclair Knight Merz’s perspective is included at Appendix A.

Although the industry makes a great deal of use of high technology elements to support the capacity, operability, maintainability and reliability of the transmission systems, it is generally the case that the rate of technological change impacting directly on the elements having the most significant impacts on the ODRC valuation of a transmission system is measurable on a decade-by-decade basis.

Thus if technological change rate were the primary driver for revaluation then periodic revaluation at, say, 10 year intervals would likely suffice. Any more rapid deployment of revolutionary technology anywhere in the world would be quickly recognised and discussed within the Australian industry and used to trigger a revaluation if necessary.

Given that a prudent asset owner in this industry with a high commitment and obligation to supply the ‘essential service’ of electricity transmission would only consider commercially proven technology for immediate widespread application[6], any new technology would be apparent to the industry for several years and deployed no faster than incrementally until it was considered commercially proven.

4.3 Other causes of ODRC variation

Notwithstanding that the rate of technological change in the electricity transmission construction industry is fairly slow, there are several other reasons why the ODRC value calculated from time-to-time might vary for a given asset. These include:

- commodities costs vary continuously, noting that many high voltage components have significant levels of copper, aluminium, iron and steel
- foreign exchange rate variations in imported components. It is of note that the EHV componentry of transmission substations contain a higher level of imported elements than a typical distribution level substation
- productivity changes in the construction industry
- supply/demand balance in the construction industry
- changing environmental factors (OH&S requirements, density of other services and neighbours, increased limitations on dust, nuisance etc)
- changed approvals factors (eg easement acquisition, buffer zones),
- value of land

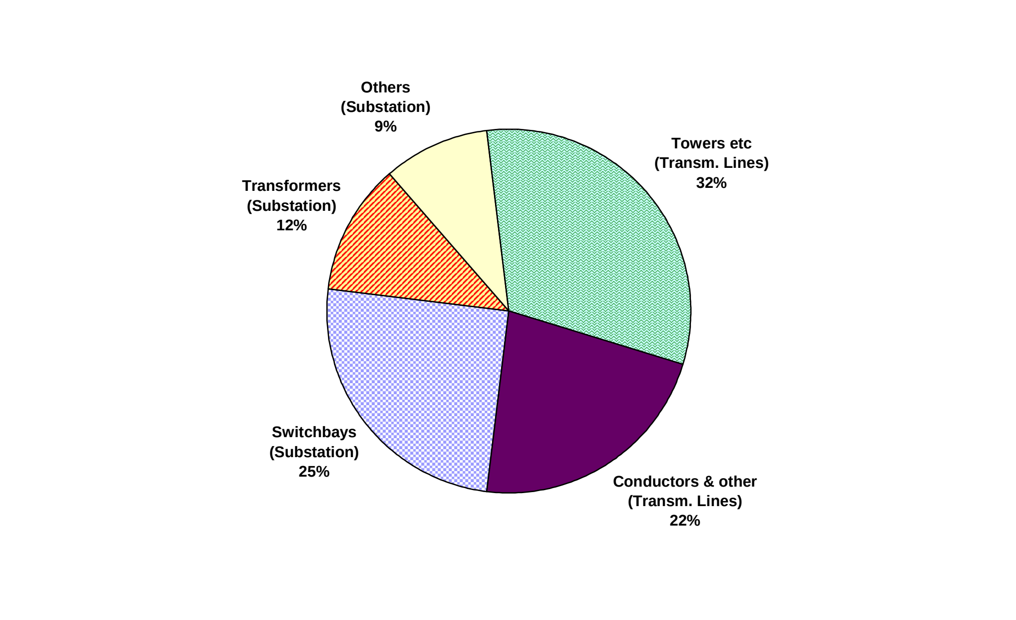
The replacement cost of an asset owner’s electricity transmission system in Australia would typically be in the range AUD1Billion to AUD4Billion[7]. The make-up of such an asset would be broadly represented by that shown in Figure 1. With reference to this figure:

- Transformer costs have key elements of copper and iron
- For high voltages, a high proportion of switchgear elements are imported
- Tower costs are heavily influenced by steel prices
- Conductor costs are heavily influenced by aluminium and steel costs

[6] Interpreting the notion of ‘deprival’ to mean complete, or at least widespread, deprival.

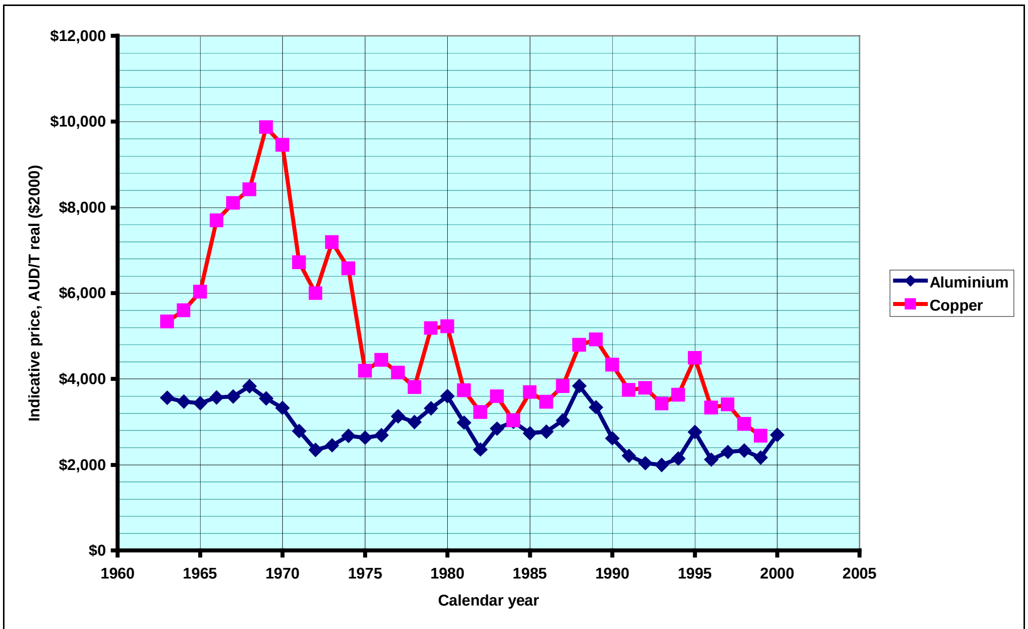
[7] For example in the Transgrid decision the initial asset value was set by the Commission at $1,935M.

■ **Figure 1 Typical breakdown of replacement costs for an electricity transmission business (operating assets)**



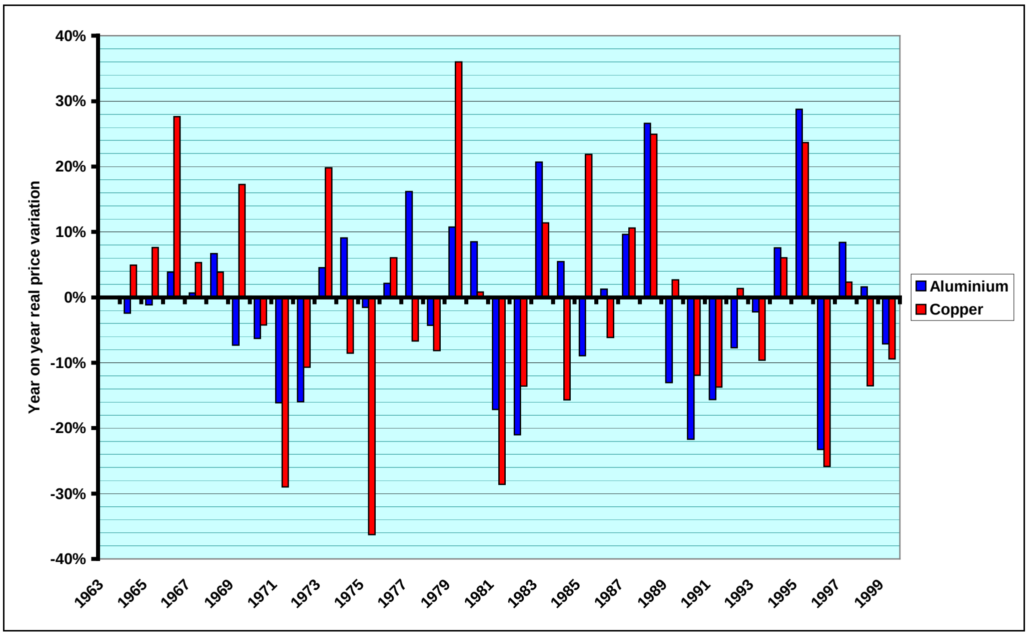
With respect to variations in commodities costs, an indication of historic trends in copper and aluminium commodities prices can be gained from Figure 2 below. Figure 3 shows the year-on-year variations in these prices. It can be seen that large fluctuations in prices of the underlying commodities from year-to-year may arise.

■ **Figure 2 Historic variations in key commodities costs**[8]



[8] Data is from ABARE Commodities Statistics 2001 Tables 9, 236 and 266. CPI corrections for the calendar year are based on the average of the two financial years adjoining.

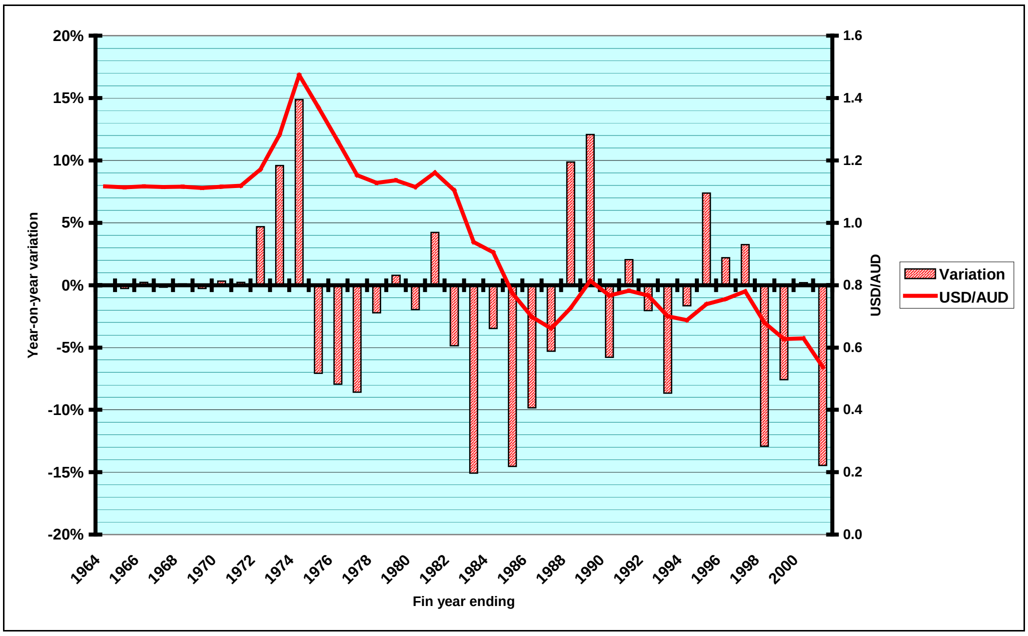
■ **Figure 3 Year-on-year real price variations in key commodities**



Similarly, Figure 4 shows the historic levels and year-on-year variation rate for the Australian dollar against the USD. Again, large annual variations are obviously possible in the cost of imported componentry caused by exchange rate fluctuations.

Obviously a significant component of the capital cost of a project relates to matters other than commodities and exchange rates (eg local labour content) which may have the effect of damping actual construction cost price variations from those indicated. Some element of these factors would necessarily remain however.

■ **Figure 4 Foreign exchange rate trends**



Productivity level changes in the construction industry would occur over longer timeframes and hence would not justify frequent revaluations just because of this factor.

Supply and demand balance factors in the construction industry and competitive factors between constructors do however lead to significant variations in the cost of construction of projects.

Consequently, although the rate of technological change in the electricity transmission industry alone might justify a less frequent re-valuation than every five years, other factors impacting on the valuation can change more rapidly and hence a five yearly revaluation would be recommended (if re-valuation is the selected methodology).

4.4 Uncertainty within ODRC valuations

Estimating the capital cost of a replacement asset using a database of MEE costs is not unlike the process of estimating the capital cost of a prospective new project development in the industry. It is recognised that there is a level of uncertainty within such a capital cost estimate that depends on the level of effort (and hence cost expended) in the estimating process.

The most accurate process is to undertake a detailed design and technical/commercial documentation and to release this as a Request for Tenders to experienced construction contractors for firm pricing. This is impractical, and unreasonable, and the compromise used in practice is to maintain databases of costs for system elements based on past actual projects and budget prices received over time. This type of estimate has an uncertainty level necessarily higher than a set of firm quotations will provide. Since the spread of prices received under a firm pricing Request for Tender could easily be ±10%, budget pricing processes tend to have larger uncertainty levels and a ±10% range of uncertainty would thus be considered typical.

A range of factors that might create uncertainty or variance within an asset valuation are listed in Appendix A.7.

Obviously a skilled and experienced practitioner can use judgement to account for and manage many of these potential variation areas. Some uncertainty necessarily remains however and given the large values involved could represent substantial wealth transfer potential between asset owners and asset users at any valuation where the valuation flows directly into the tariffs charged.

Because of this dependency of an ODRC valuation upon such skill, experience and judgement of the practitioner, and upon the calculation cost and MEA database maintenance costs of more detailed evaluations to reduce the uncertainty, the revaluation process necessarily is less robust and transparent, and more complex, than a roll-forward process.

Nevertheless, each re-valuation has the potential to transfer wealth in an unintended fashion between asset owners and asset users by an amount of the order of ±10%, which is considered material.

5. Issues and discussion

5.1 Consistency with deprival value

The initial values ascribed to all the primary transmission system businesses in the NEM have been generated using ODRC methodologies.

The current carrying value[9] of these assets should be traceable back to the initial values via the depreciation accounts, capex expenditures and published CPI factors.

Provided any lower economic value (such as if an external tariff (and hence revenue) cap criterion applied) is not triggered then an ODRC valuation is considered to be consistent with the deprival valuation preference called up in COAG 19 Aug 94 and incorporated by reference in the NEC 6.2.3(d)(4)(iv).

Between revaluations it is normal for an asset value to be rolled forward with adjustments for depreciations and for additions and subtraction to the asset register. Since an ODRC cannot practically be continuously calculated it is considered that such rolling forward between revaluations remains consistent with the earlier deprival valuation provided the depreciation regime is considered reflective of the consumption of the asset's utility in the intervening period.

If the Initial Capital Base (ICB) were calculated using a deprival valuation, and if there is no technological or (real) cost changes in the industry over the asset's life, then rolling forward of the asset base tracks the ODRC value (if the depreciation profile is selected as an annuity[10] style depreciation. This profile is shown in Figure 5.

For the purposes of this Figure 5, the capex is taken to be all of a type that does not extend the life of functionality of the underlying asset. If the capex did extend the life or functionality then the ODRC profile would be higher and would match the rolled-forward depreciation (with capex) line. Figure 5 is shown as it is to illustrate the issues discussed later in Section 5.3.

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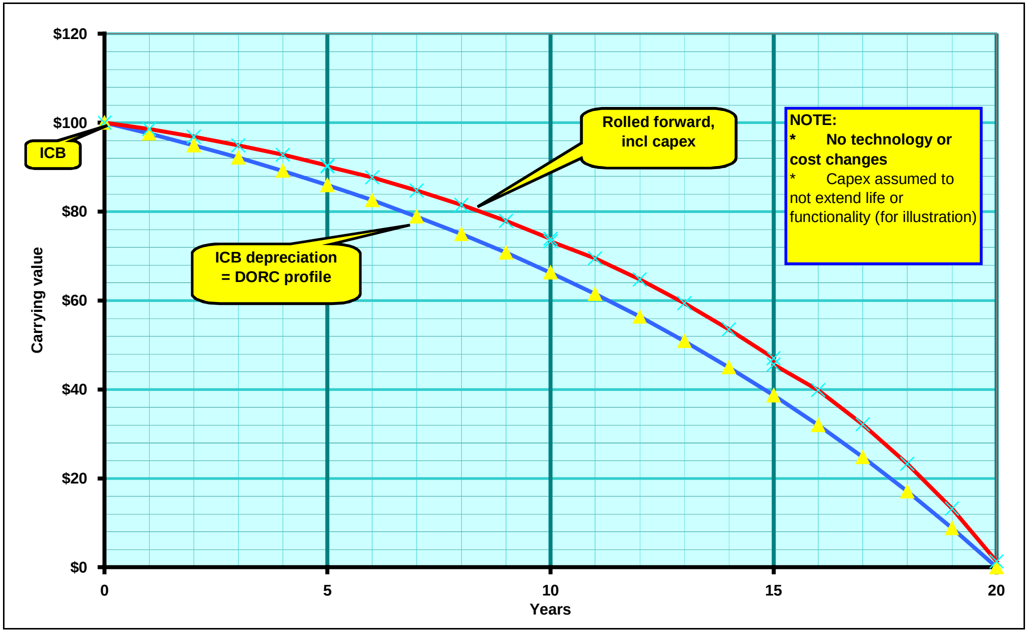
9 Carrying value in this context is the book value for tariff setting purposes and is not necessarily the same as accounting book value for corporate reporting purposes or tax book value.

10 also known as "credit foncier", or equal payments including principal and interest (per most home loans)

■ **Figure 5 Rolling forward (no technology or cost changes over life of asset)**



A deprival valuation is, by its nature, an assessment of the value of an asset at a particular point in time in recognition that the value of the asset might have diverged from the depreciated historic cost of the asset. Logically, this acknowledgment should be extended to recognise that the tendency to diverge from an appropriate value under any non-economic based depreciation regime is a continuing one, and that consequently a valuation process logically implies subsequent revaluations to consider, and if necessary, correct for the continuing divergent trend.

AASB 1041 (July 2001) "Revaluation of non-current assets" provides:

> *5.1 Subsequent to initial recognition as assets, each class of non-current assets must be measured on either:*
>
> *(a) the cost basis: or*
>
> *(b) the fair value basis, under which revaluations must be made with sufficient regularity to ensure that the carrying amount of the asset in the class does not differ materially from its fair value at the reporting date ...*

The purpose of accounting standards such as AASB 1041 is for reporting purposes and not for the derivation of regulatory tariff setting. Notwithstanding this, that the asset valuation should be consistent with Australian Accounting Standards was explicitly called up in the COAG agreement of 19 August 94. Accounting Standards can in any case be considered for guidance.

'Fair value'[11] in AASB 1041 is not identical to deprival value but in this context of revaluation frequency it is considered analogous.

[11] Fair value in AASB 1041 is 'the amount for which an asset could be exchanged, or a liability settled, between knowledgeable, willing parties in an arm's length transaction'

In the guidance notes to the above clause 5.1 of AASB 1041, at 5.1.11, the standard suggests:

> *Where a class of non-current assets is measured on the fair value basis, the frequency of revaluations depends on the frequency and materiality of changes in the fair values of the assets within that class of non-current assets. Where the fair value of an asset in the class of non-current assets being revalued differs materially from its carrying amount, a revaluation is necessary. Some non-current assets may experience frequent and material movements in fair value, thus necessitating revaluation each reporting period. Such frequent revaluations are unnecessary for non-current assets that experience only immaterial movements in fair value. In these circumstances, revaluation every three years may be sufficient. The requirement in paragraph 5.1(b) may be met by indexing the carrying amounts of non-current assets in reporting periods between more comprehensive valuations.*

Thus we believe that rolling-forward the asset base is consistent with the deprival value (previously determined) provided some mechanism is put in place to ensure that over time, the departure of the carrying value from the deprival value if such were continuously calculated, does not become material.

5.2 Maintaining the consistency of a rolled-forward asset base with deprival value

We see two possible mechanisms for providing this outcome:

- revalue the asset at a frequency estimated to provide that the departure of the value from the deprival value is not material over this period, or
- use a depreciation mechanism between regulatory reset dates that anticipates the deprival value that would be expected at the next reset date (call this mechanism economic depreciation).

We observe that this second depreciation profile method is countenanced in the Draft Statement of Principles issued by the Commission in 1999 at Proposed Statement S5.5 on Page 64, in that a prospective deprival value is calculated for the next reset (in five years' time) and the depreciation profile is directed to achieve this closing carrying value. Because such a process limits the divergence of the carrying value from the deprival value this depreciation profile could be used with a roll-forward approach to provide the necessary economic value profile without the problems of revaluation at and for the start of each regulatory reset period.

The box at the top of page 29 of the Draft Statement of Principles appears to advocate this methodology.

5.3 Difficulties with periodic revaluations

With respect to periodic revaluation of the asset base via an ODRC calculation, we can observe several difficulties with this approach.

Any revaluation process creates the potential for a disconnection between previous capex expenditure decisions and the going-forward value of the assets embodying the capex expenditure. Several cases may be identified.

If capex produces a new identifiable asset (such as a new transmission line to a new load centre), then provided the capex was prudent and used the appropriate technologies and design, the treatment under a revaluation a short time later is straightforward – the asset base would increase by approximately the level of the actual capex expended. This is the appropriate and desired outcome and provides appropriate signals for asset owners to investigate and undertake this type of project.

Consider however the case of refurbishment capex on an existing asset that allows the asset to achieve its design life but does not enhance the functionality of the asset. This might include a major repainting program of transmission towers for example. While minor painting programs might be expensed, and hence recovered under the opex building block, a major program is appropriately a capex expense as its utility is consumed over a number of years.

If the painting program were followed by an ODRC re-valuation however the transmission towers would be valued using the MEE for new transmission towers and depreciated to reflect the proportion of life consumed of the overall towers. The recent expenditure on painting would not be reflected in an increase in the asset value and the asset owner would not see a return of and on this painting expenditure.

Thus there is a perverse incentive against this type of appropriate capex expenditure in the case of re-valuations.

Whilst a ‘patch’ for this perverse incentive might be to allow such refurbishment capex to be expensed, in cases where this expense is large it would create a ‘lumpy’ revenue profile and bypasses the intention of allocating capital costs across the period of usefulness of the expenditure. This would result in allocative inefficiency between customers who might use the asset over different periods in the asset’s life.

While there are provisions[12] for gaining NEMMCO’s approval as to the prudency of the proposed capex, in practice this is only practical for ‘headline’ projects and there are a myriad of small capex expenditures that could not reasonably be handled in this manner.

The problem above can be generalised to capex in general that is below asset recognition level. A transformer might commonly be a typical asset in an asset register of a transmission company. At revaluation, an MEE value based on a database of appropriate transformers would be ascribed.

A transformer is, however, actually made up of subsystems including monitoring systems, sensors, fans, bunding etc. Consider, for example, capex on an enhanced sensor, or sensitive elements such as monitoring systems which have a life shorter than the transformer life and which need to be replaced periodically throughout the transformer’s life. These subsystems are typically below asset recognition level and are bundled into the transformer value. Capex such as this below asset recognition level, is lost on subsequent revaluation - again creating a perverse incentive against such expenditure.

[12] NEC Clause 6.2.1(d)(4)(ii)

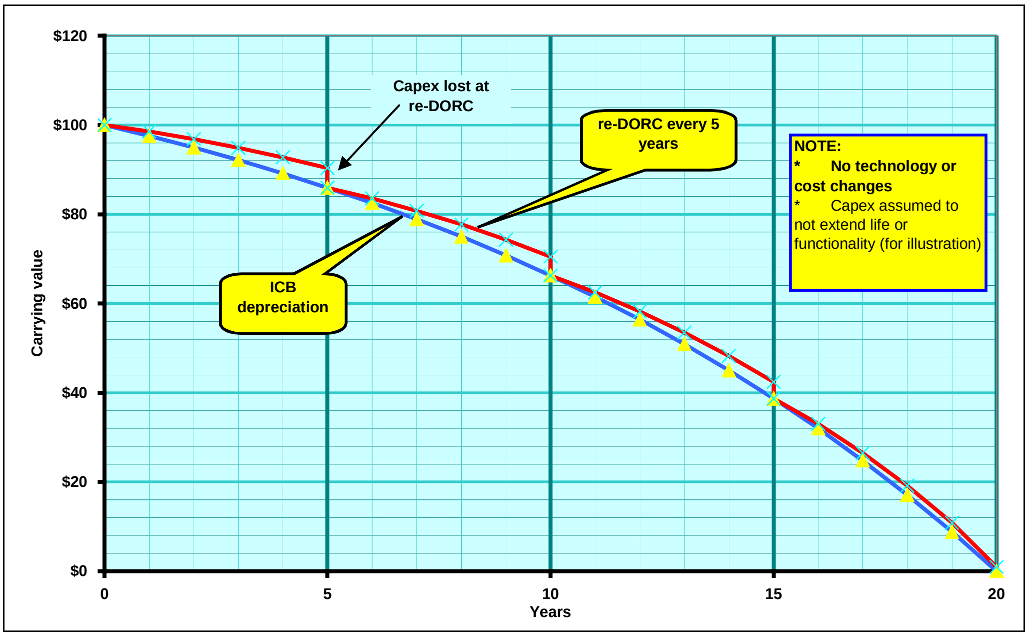
Capex that extends the life of an asset may not be captured at its actual cost at a subsequent (near) revaluation because (even assuming the same MEE replacement) the changed depreciation allowance over the revised life versus the depreciation allowance over the previous life expectancy would only equate to the actual capex under quite coincidental circumstances.

Capex that incrementally enhanced the functionality of an asset but (because of the finite step sizes in MEA databases), did not result in a different MEA replacement being selected when assessed at a subsequent revaluation would likewise be lost.

Revaluation thus has the potential to produce quite distorted signals to asset owners with respect to capex. Since opex is not subject to this distortion there may be an uneconomic bias by the asset owner towards spending higher opex costs rather than making prudent capex investments.

This problem is illustrated in Figure 6.

- **Figure 6 Re-ODRC every five years**



The NEC contains safe-harbour provisions (such as Clause 6.2.3 (d) (4) (i) and (ii)) protecting the asset value where the prudency of the investment has been pre-agreed or the asset value risk has been accepted by another party (eg a customer under a take-or-pay agreement). Revaluations must recognise these pre-set values or else these provisions of the code would be unreasonably defeated. The existence of such constraints would increase the complexity of a valuation calculation where (for example) the asset with a fixed value was a component of a system that was optimised to a system of a different nature. For example if a section of transmission line pre-agreed as prudent by NEMMCO is embedded within a longer link that is later optimised to the cost of an alternative local embedded generation scheme. Such complicating factors would increase the cost of the valuation process and reduce robustness and transparency. These provisions are more easily addressed with a roll-forward regime.

The above factors relate to the potential loss (to the asset owner) of the value of some of the capex that might otherwise be a prudent investment. Capex investment is an extremely important element of the long term provision of transmission services. For example in the case of TransGrid, projected capex just for identifiable projects was generally in the range $50m to $100m per annum. These amounts are generally larger than depreciation amounts and of the same order as opex costs.

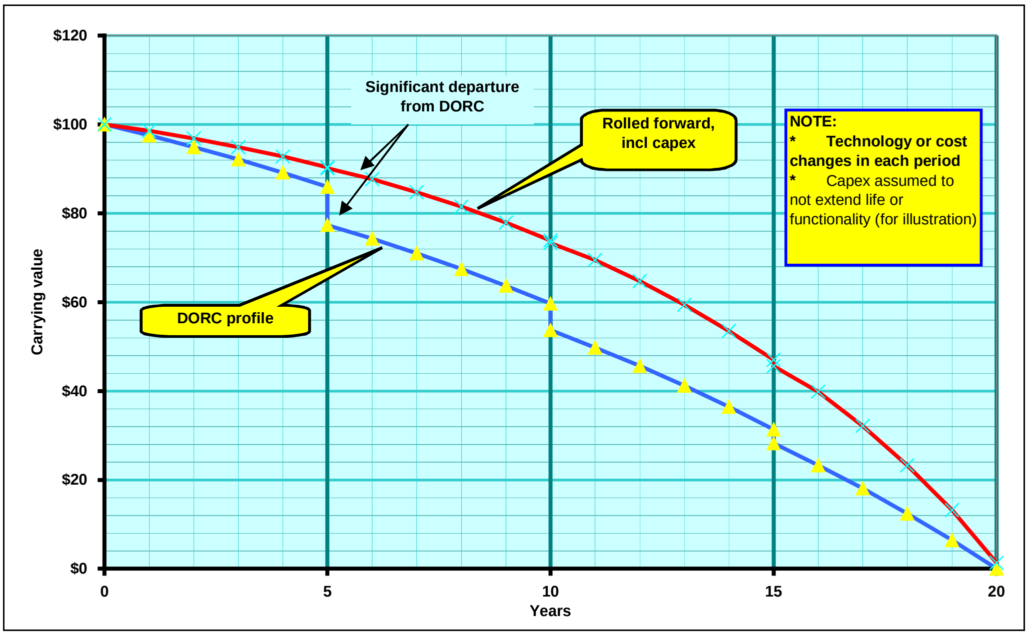
5.4 Difficulties with rolling-forward

This Section discusses the difficulties seen with continuously rolling forward an asset base without any re-alignment with a market test type valuation either via periodic re-valuation (using deprival valuation techniques) or using the projected deprival/ODRC value to guide depreciation.

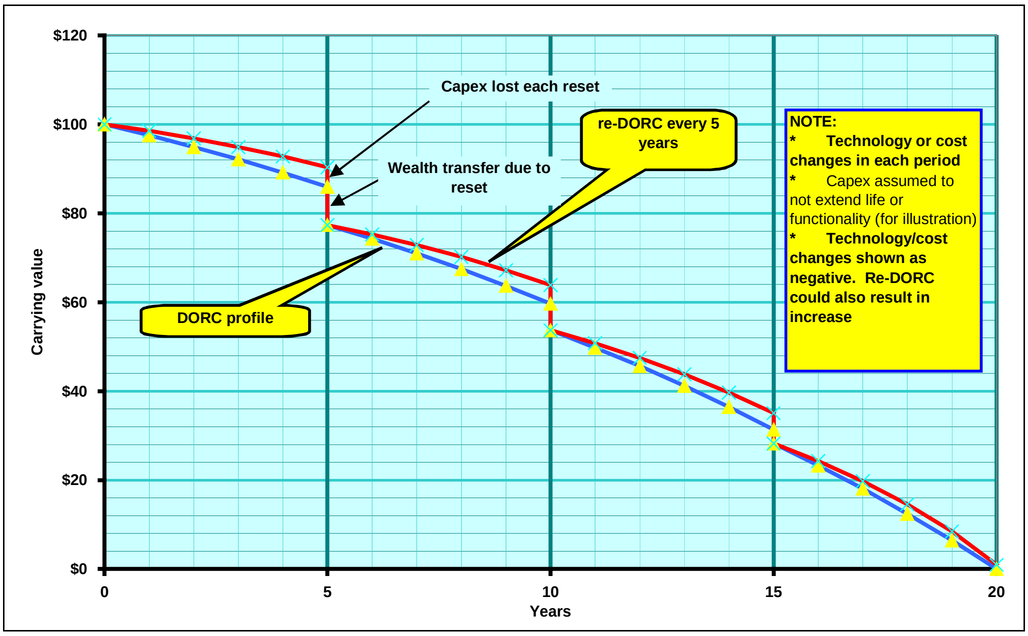
The primary deficiency with rolling-forward without one of these controls is that (as noted in Section 5.2) it is expected that over time the value would diverge from a deprival value.

This tendency is illustrated in Figure 7 which (for the purposes of the illustration) assumes technological advancements and/or real cost reductions in the industry occur over the life of the asset and which mean that the deprival/ODRC value varies from the rolled-forward carrying value. For comparison, Figure 8 shows the same circumstances with re-ODRC calculations every five years. In this case the carrying value is a closer match to the actual deprival/ODRC value but the difficulties noted in Section 5.3 remain. The asset owner also suffers a loss in value at each reset (or gains an increase in value if the assessed ODRC were alternatively higher than the previous carrying value).

- **Figure 7 Rolling-forward (without guided depreciation) – technology advancements and/or real cost reductions apply over asset's life**



■ **Figure 8 Re-ODRC every five years – technology advancements and/or real cost reductions apply over asset's life**



As well, capex roll-forwards by themselves do not contain any drivers for the networks businesses to:
(a) ensure that the most cost-effective solution is chosen, and
(b) ensure that the selected capex project is implemented in the most efficient manner.

The overall effect of such a situation is that under a roll-forward scenario there is a greater onus placed on the regulatory body to evaluate the "prudency" of the capex spend between ODRC resets. It is doubtful that they would have the necessary skills and knowledge to adjudicate effectively on the "prudency" of all network capex, and much of it is contained within less well defined "programs", rather than large specific projects.

5.5 Robustness

In terms of the robustness of the process, the asset base under revaluation has already been noted to have an uncertainty of (indicatively) ±10% based on the inherent uncertainty in budget cost estimation processes.

There are also additional potential variance factors between practitioners (due to different MEE databases, modelling software, regional experience for example) and the timing of the estimate relative to commodity and foreign exchange variations (see Section 4.3) and construction market supply/demand balance factors.

Collectively, these factors create a 'grey band' of potential ODRC values that might be generated at any revaluation process.

The asset owner has an information advantage with respect to the asset and the construction industry sector relevant to the electricity transmission industry.

The asset owner also has a ‘first-mover’ advantage in being able to generate and table a valuation for subsequent review by the regulator.

It would be logical for these factors to create a systematic bias in the valuation assessment towards the asset owner’s interests. More frequent revaluations would compound the impact of any such systematic bias that existed.

Roll-forward is thus a more robust process than revaluation.

It should be noted that the asset owner also suffers from the grey band of asset valuation uncertainty because of the possibility of an outcome towards the lower end of the grey band notwithstanding the argument above that the risk of this outcome might not be symmetrical. Such an uncertainty can create financing difficulties (in lower gearing levels or in increased equity costs to the extent the risk is not diversifiable).

Note that where ODRCs are done prospectively to guide a depreciation profile this difficulty does not arise as a biased ODRC would be compensated (exactly in an economic sense if the WACC was exactly the correct economic rate) by the depreciation function.

It should also be noted that even if a roll-forward approach were adopted, an ORC based asset register needs to be maintained nevertheless for the asset for the CRNP allocation at NEC Cl 6.4. Also, periodic ODRC valuations would still be recommended to guide the depreciation profile and to monitor the relationship between carrying value and economic value of the asset.

Whilst we recognise the limitations of the ODRC methodology, we (SKM), as well as other consultants, have been progressively refining our ODRC techniques to minimise the effect of these limitations. These refinements include development of "brownfield" adjustment factors, separate valuation of major "child" assets, below the asset category level, more complex terrain factors, etc. With further development of the technique and with standardisation of the algorithm the robustness of the ODRC technique should improve.

5.6 Transparency

There are a number of practical issues surrounding a deprival or ODRC valuation that illustrate the difficulties of a slavish adoption of the deprival model or the new entrant bypass model (often used for ODRC).

For example, where an existing urban transmission line is constructed as an overhead line, any future new entrant could well need to construct the bypass asset using the much more expensive underground cabling technique. The alternative underground cable can not be said to have the same functionality as the overhead line as it provides benefits in terms of aesthetics etc that the overhead line does not have and these benefits are the reason that communities are demanding some future infrastructure be placed underground.

In this case the added functionality of an underground line would be for the benefit of the community rather than the asset owner.

It would be an unintended outcome if the asset owner of an existing overhead line were rewarded with a higher ODRC on the basis that a new entrant bypass asset would cost more because these developing community expectations would require undergrounding. If this occurred, the asset user (community) pays higher tariffs consistent with an underground asset and yet the community does not get the associated benefits of the underground cable unless it is actually built.

To avoid this distorted outcome it has become the practice to value urban overhead transmission lines using an overhead MEE and to value an underground line (if it was necessary and appropriate to underground in that case) using an underground MEE.

This is nevertheless a departure from the interpretation of an ODRC as the new entrant bypass cost.

In the case of the deprival model under the above scenario it would be necessary to question the extent of the 'deprival' that is being modelled. Is the asset owner being 'deprived' of the physical asset as well as its right to exist in its present form (eg an overhead line in an urban environment)? Alternatively, does the community's acceptance/forebearance of an existing overhead asset because of its long-standing presence at that location represent a proprietal or other interest for which the asset owner should be rewarded? In practice such value is not accredited to the asset owner's account in the valuation process.

These, and other factors such as the valuation of easements, are examples of the difficulties in the implementation of ODRC and deprival valuations that mean that the ODRC and deprival values can not be as robust (including reproducible), and transparent as the rolling-forward method.

These difficulties would be substantially reduced (and transparency enhanced) if a detailed manual or standard for the ODRC procedure for regulatory purposes were promulgated. No such manual has been developed[13].

As noted in Section 5.4 above, if a roll-forward approach is adopted without any control over the eventual divergence of the carrying value from a market-type value, then to the extent that the regulator is exercising judgement about the prudency of capex, and given the significance of capex in a typical electricity transmission business, then this would also suffer from a lack or robustness and transparency.

5.7 'Optimising back-in'

An issue that might be considered is whether an asset that was optimised out, or down to a lower capacity, at a previous ODRC should be optimised back in, or back to its actual capacity, if the asset is now more utilised due to, for example, load growth in the intervening period.

It would seem unjust if an error in a previous valuation was not corrected or if a previous valuation was known to have been conducted to exclude a class of asset now felt to be appropriate for inclusion (such as easements).

[13] There are some guideline documents such as NSW Treasury guidelines for the NSW electricity system valuations but these are not comprehensive, nor have they been developed and consulted upon for the purpose of widespread usage.

However, if the previous ODRC was undertaken satisfactorily yet an asset was appropriately optimised down (or out), it should be considered whether it should be subsequently optimised back up (or in).

If it is decided to re-ODRC the whole system, then the process will automatically return an asset previously optimised down or out if the load growth has been such that this is now justified by the method.

If there is to be a roll-forward of the asset base however, then this method should not allow selective optimising back-in of a part of the asset. This would be the same as selecting a part of the system for a re-ODRC rather than the whole. There is a risk that only the parts of the asset that might show an increase in value are selected for revaluation and other areas that might show a decrease are rolled-forward. Of course the reverse could occur if the asset users had the opportunity to select which elements were to be revalued.

Thus selective revaluation creates a bias in favour of the party that gets the right to choose which subset of the whole asset is to be revalued.

Hence it is recommended that either the whole asset should be revalued or else the whole asset should be rolled-forward.

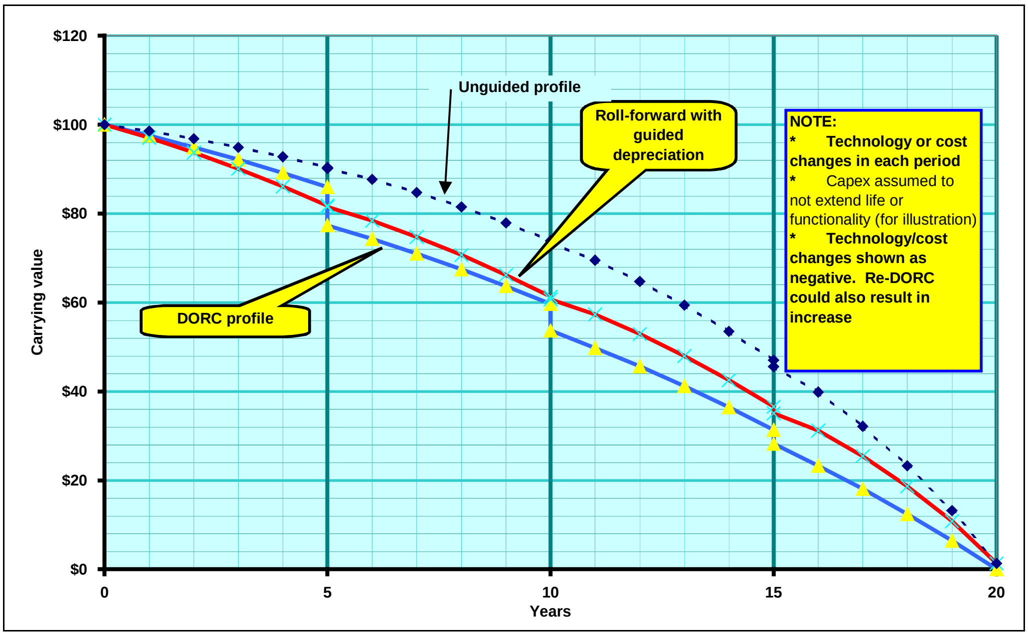
Either of rolling-forward the whole asset base or a full re-valuation would achieve a reasonable outcome in this case.

5.8 Illustration of rolling forward with guided depreciation

An illustration of the impact of the rolling-forward case (with guided depreciation) where there are technology changes and/or (real) cost reductions in the industry is shown in Figure 9.

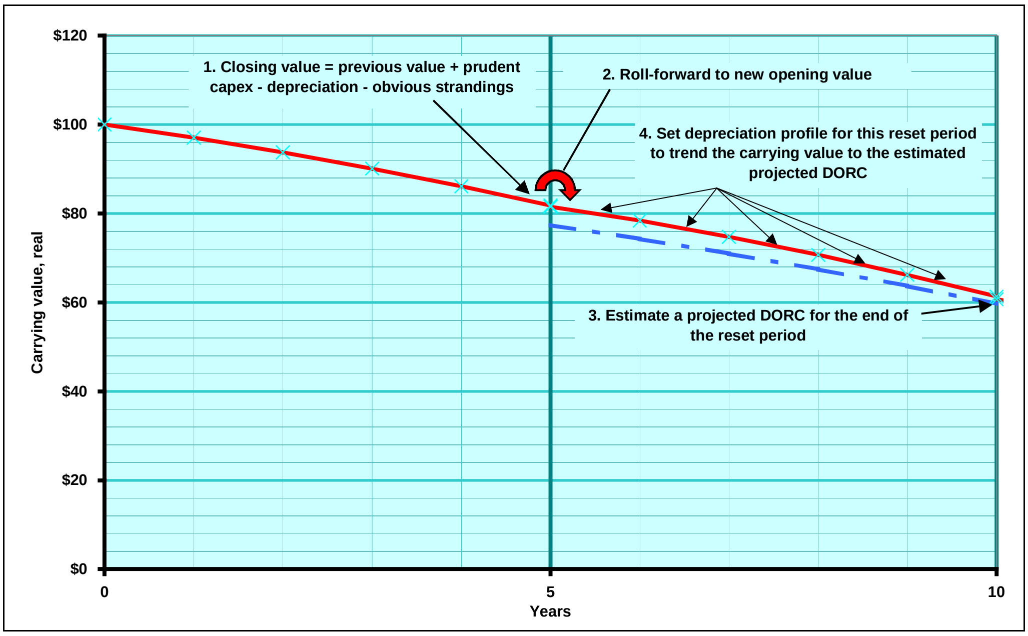
The method is shown to both track the deprival/ODRC value, as well as maintaining the signals for the asset owner to expend prudent capex.

■ Figure 9 Rolling-forward with guided depreciation



The algorithm for the process of rolling-forward with guided depreciation is shown in Figure 10. The process is shown for the case of a regulatory reset at Year 5 to cover the period from Year 6 to Year 10.

■ Figure 10 Algorithm



At step 1, the closing asset value for the previous regulatory period is calculated as the previous carrying value (adjusted to current cost by adding CPI escalation if the real cost of capital is to be applied). Prudent capex expended in the previous period is added, depreciation from the previous period is deducted as are obvious strandings. In this methodology, because a re-ODRC is not undertaken for the time T=5 years (where the optimisation process would detect partial strandings), only cases where an asset had no ongoing use would be considered here.

Step 2 rolls this closing asset value forward to become the opening asset value for the current reset period.

In step 3, a projection is made of the deprival/ODRC value that might apply at the end of the current period, that is at Year 10. In practice because technological advancements do not tend to occur suddenly, and because industry cost changes can largely only be projected using long term industry productivity improvement data, the projected deprival/ODRC value at Year 10 would likely be based on an estimate for:

- a current (Year 5) deprival/ODRC value[14],
- adjusted for expected capex in Years 6 through 10, and
- adjusted for annuity depreciation for the coming five years (Years 6 through 10) relative to the total remaining economic life.

At Step 4, the depreciation profile for the next 5 years is set such that the residual value that would be reached upon depreciating the opening asset value (from step 2, adjusted for expected capex) via annuity depreciation is equal to the projected Year 10 deprival/ODRC value calculated at step 3. This is a simple calculation.

5.9 Who bears the risk?

The stakeholder group that bears the risk of changes in technology or industry costs in each case (re-valuation or roll-forward) is different.

A comparison of the party bearing the risk of technology/industry cost changes for each option is shown Table 1.

Table 1 Risk allocation for technology changes and industry costs[15]

Stakeholder	Asset owner	Current users	Future users
Case 1: Roll-forward, unguided depreciation			Primarily bears risk because of lost opportunity for reduced costs
Case 2: Revaluation every 5 years	Bears risk		
Case 3: Roll-forward with guided depreciation		Primarily bears risk within depreciation over the next 5 years	

[14] As noted in Section 5.5, uncertainty within this calculation of ODRC is not as much of a problem as if the ODRC was being used to immediately reset the asset value, hence the calculation and review of the calculation might be less costly than ODRC calculations that have been used to establish the ICB for instance.

[15] Only downside risk is illustrated. Upside risk is to the benefit of the other stakeholders.

In deciding whether particular risk allocations are reasonable, it should be noted that at the time the risk materialises each of the asset owner and existing asset users have sunk-cost assets and further that neither party can control the technology or cost change risks or their impacts.

In the first case of rolling-forward with unguided depreciation, future users may be subjected to signals for uneconomic bypass of the asset because the asset value upon which tariffs are based has departed from the ODRC value.

In the second and third cases in Table 1 the risk allocation is economically neutral (because both asset owner and users have sunk costs and no ability to control/mitigate the risk), although it might be noted that in case 3 (roll-forward with guided depreciation) the risk is generally spread over more parties.

In case 3 when a new technology (etc) appears, the benefit of the new technology (etc) and its impact on costs is seen by future users whereas existing users pay for the reduction in value of the asset via depreciation charges over five years. If the WACC applied were exactly the correct WACC for the asset owner's business, then the asset owner would be entirely neutral to the rate of depreciation selected.

In each of the three cases above, if a radical new technology appeared that completely changed the industry or its cost structure, then the asset owner would largely bear this risk:

- in case 1 by widespread bypass using the new technology,
- in case 2 by a large asset value reduction at the next re-ODRC, and
- in case 3 by the asset owner being unable to practically charge high enough tariffs to recoup the value change via depreciation (or face widespread bypass).

With respect to capex (or at least that capex that doesn't expand functionality or extend the asset's life), case 1 has the best allocation because the capex is depreciated over the remaining life of the asset. Case 3 depreciates the capex over the next regulatory period and case 2 results in a loss of the capex to the asset owner.

Hence case 1 is better than case 3, which in turn is better than case 2, in this regard.

Capex that alternatively expands the asset's functionality or extends its life is depreciated over the remaining life in all three cases and hence there is no particular benefit within any of the three regimes (cases) in respect of this capex[16].

[16] Although it is noted in Section 5.3 that capex that extends the asset's life may not be fully captured in case2 – re-valuation.

6. Recommendation

6.1 Recommendation

Without any additional ameliorating elements, revaluation at periodic intervals where that valuation adjusts the carrying value of the asset at that time, has several negative features:

- a significant disincentive for efficient investment in those types of capex that do not result in an ODRC value increasing by the amount of the actual expenditure,
- higher calculation costs, although it is noted that forms of ORC and ODRC may nevertheless need to be calculated on an ongoing basis anyway, and
- reduced robustness and transparency caused by the dependence on the skill, judgement and experience of the practitioner and the inevitable grey band of uncertainty and variance in the value calculated using the method

On the other hand the roll-forward methodology applied without ameliorating elements does not contain the incentive for the service provider to improve efficiency in the provision of transmission services provided out of the matching of the asset value with any sort of competitive market value such as that provided, at least theoretically, by periodic re-ODRC valuation.

Indeed it can be asserted that over a long time with only roll-forward carrying value, the carrying value might depart materially from what would be the deprival value at that time.

Further, given that with continuous roll-forward the cumulative effect of the regulator's judgement on capex as prudent or otherwise will grow to a significant size, continuous roll-forward without some market control mechanism also lacks robustness and transparency.

Of these negative elements, it appears attractive to ameliorate the deficiency in the roll-forward method by incorporating a guiding element based on deprival value (in practice ODRC) into the depreciation profile. Although this requires a continuation of the costs of periodic ODRC calculations these are largely required anyway within the distribution of the asset value across the CRNP elements of TUOS.

Further, any uncertainties, errors or biases within the calculation of ODRC for the purposes of guiding depreciation do not result in a wealth transfer (windfall gain or loss) between asset owners and users except to the extent that the WACC applied is not economically correct – which should only be a second-order factor.

Likewise there is no benefit to the asset owner from any systematic bias in the ODRC used for distributing the asset value across the CRNP elements of TUOS.

Thus the level of regulatory oversight of the ODRC calculation that might remain for these purposes should be reduced and the robustness and transparency provided by rolling-forward method should not be damaged by the fact that a periodic ODRC calculation remains.

With rolling-forward the regulator has to maintain scrutiny of the prudency of capex. Once capex is agreed as prudent the owner gets to recover the costs of the capex with the rolling-forward technique (capex agreed as prudent is provided with a form of 'safe harbour').

Overall, Sinclair Knight Merz would thus recommend the rolling-forward method (with economic guided depreciation) as a better method rather than regular, periodic revaluations using deprival value/ODRC techniques or of rolling-forward on an ongoing basis without any guiding of the carrying value profile.

Appendix A Electricity industry technology trends impacting on valuation parameters

A.1 Background

Over the last few decades there have been many technological changes which have impacted on the design and capability of transmission networks. However, in general these changes have resulted in asset owners being able to work existing assets harder and hence delay network reinforcement rather than significantly reducing the cost of new assets. Indeed, in many cases the ability to defer major capital works has provided the economic incentive to introduce these new technologies.

As a consequence of the increased utilisation of the network, use of these new technologies won't necessarily result in a significantly lower cost optimised network

A.2 Description of technological changes

The major technological changes related to EHV transmission technology have generally been in the areas of:

- Insulation and EHV cables,
- Circuit breakers,
- SCADA ,
- Transformers,
- Power electronics, and
- Provision of reactive power

A.2.1 Changes in insulation and EHV cable technology

Nearly all EHV networks rely on air as the principal insulating medium. Air insulation is a simple, well-understood and economic technology and has been used for as long as electrical networks have existed. It relies on keeping the conductors an appropriate distance from each other and from ground. This is achieved by insulator strings of appropriate length and suitably high towers that keep the conductor mid-span an acceptable distance above ground. The technology has been easily scaled up to achieve the EHV insulation levels that are now commonplace. Air insulation is still used under most conditions where space is not at a premium.

However, where space is limited or undergrounding is required then air insulation can be replaced by more technologically advanced (and more expensive) insulating mediums.

Improvements in cable technology have led to underground cables operating at increasing voltage levels and capacity together with improvements in reliability. This has been achieved together with a downward trend in both unit costs and costs per MWh delivered. Technological improvements include:

- Development of Cross-linked Polyethylene (XLPE) as an insulating medium,
- Improved jointing and termination technology (quicker to make, more reliable, increased capacity);
- Improved capability for detecting underground faults;
- Development of condition monitoring techniques for detecting incipient faults;

- Higher thermal capacity achieved through use of better materials and improved thermal analysis.

These developments can be characterised as:
a) enabling cabling to be considered technically feasible at higher voltages, and
b) providing incremental improvement in performance and cost

Nevertheless, underground cabling costs substantially more than traditional overhead lines where space permits the use of the overhead option, and this relative cost difference is expected to continue into the future.

A.2.2 Changes in circuit breaker technology

Conventional outdoor
Circuit breaker technology has progressed over the last fifty years with the transition from bulk oil insulated switchgear through to air blast technology, minimum oil switchgear and more recently to vacuum and gas insulated technology.

Each development phase has been aimed at reducing the dependence on oil as an insulating medium with its associated high cost and intensive maintenance requirements. Air blast technology still exhibited high costs and intensive maintenance requirements due to the number of seals and moving parts involved. The noise associated with operation of the circuit breaker was also of concern in built up areas.
Gas insulated switchgear is being used for new installations and as a replacement for older switchgear when determined by asset condition. Gas insulated switchgear is under continuous development thus its cost has yet to stabilise.

Gas insulated switchgear costs vary depending on the application. In general, increasing the voltage, the fault interrupting capacity or the current carrying capacity of the circuit breaker will increase the cost. When a circuit breaker is replaced, its duty requirement is often also increased (typically an increase in fault interrupting capacity) resulting in the need to replace with a higher capacity and more expensive device.

Integrated compact switchgear
Gas insulated technology permits switchgear to be used for either indoor or outdoor applications. The technology also allows for the integration of the various individual elements that form part of a switch bay into a single switching device, including instrument transformers, isolation switches and earthing switches as an integral part of the design. In addition, the integrated switchgear generally incorporates features that are designed to permit increased use of substation automation, monitoring and control. This allows for improved fault diagnostics and condition monitoring as well as providing overall network reliability improvement. The integration provides increased functionality that cannot be addressed on an item-by-item replacement cost basis. Such integration means that the cost of an integrated device cannot be compared directly with the devices that it replaces.

However, it is clear that integrated switchgear is more expensive than discrete designs used in conventional outdoor substations. The increased cost must be offset against benefits in terms of space saving, noise reduction, reliability improvement and reduced maintenance. For example, the “footprint” of an indoor substation using integrated switchgear can be reduced to only 25% of a conventional outdoor substation. Where the switchgear is to be installed also needs to be considered in the cost/benefit analysis. For example, integrated switchgear suits CBD installations or heavy pollution environments since pollution degrades the performance of outdoor air insulated equipment.

Consequently, the drivers on equipment selection and cost are a combination of capital, operational and locational considerations.

A.2.3 Changes in SCADA technology

Over the past 30 years, SCADA (System Control and Data Acquisition) technology has made enormous advances. Before SCADA technology became routinely available, all substations were manned and centralised control was limited. All network operations were carried out under manual local control and data was manually recorded. To cope with the relatively slow manual response times and poor data availability, networks were required to have a considerable degree of excess capacity and redundancy.

Improvements in the speed and reliability of the communications technology and major advances in computing power have changed this picture dramatically. Transmission networks now routinely use SCADA technology to remotely monitor and control transmission networks in real time. The benefits of SCADA technology include the following:

- reduced manning levels,
- increased data availability,
- network optimisation (in an operational sense),
- increased network utilisation,
- increased emergency ratings,
- improved contingency response, and
- improved supply reliability.

While SCADA has not increased the capacity of individual primary plant elements such as lines and transformers, it has made possible the increased utilisation of the network as a whole. In effect, SCADA technology has unlocked previously unavailable network capacity. It is fair to say that without SCADA technology, transmission networks would have to be operated at considerably reduced utilisation levels.

A.2.4 Changes in transformer technology

Power transformer technology has varied little over the last fifty years. Transformer construction techniques have evolved to reduce the amount of oil required to cool the transformers, which has reduced the physical size of the units. However the sizing requirements of transformer cores and the electrical windings have not changed since temperature limitations and magnetic flux requirements are fixed quantities for any given transformer capacity. Transformer manufacturing costs are a trade off between the capital cost and the long term operating costs associated with iron and copper losses.

The temperature of transformer windings represents a fundamental limitation to transformer loading. In the past, simple methods were used to estimate the winding temperatures and this resulted in conservative ratings being assigned. Such ratings did allow transformers to reach their design life span but at the expense of under-utilised capacity.

One area of significant advance in transformer technology relates to real-time monitoring of the actual transformer winding temperatures. Real-time monitoring is achieved by embedding fibre optic thermocouples into the transformer windings during construction. The cost of real-time monitoring typically represents 1-2% of the total transformer installation cost.

Measurement of the actual winding temperature allows for greater emergency ratings, better condition monitoring and improved reliability for the EHV transformers, without reduction in life. As well as providing for local indication of temperature, the data can be coupled with a SCADA system for continuous remote monitoring. Since EHV transformers represent a significant fraction of a transmission network cost, real-time temperature monitoring allowing for increased utilisation will lead to long-term reduction in transformer costs on a “per MVA” basis.

A.2.5 Changes in power electronic technology

Over the past 20 years, the voltage and current rating of power electronic devices such as thyristors have increased sufficiently to allow the development of Flexible AC Transmission Systems (FACTS).

FACTS devices are now commonplace on EHV networks and include technologies such as Static Var Compensators (SVC’s) and Controlled Series Compensation of EHV lines. The flexibility and cost of the FACTS devices has even extended their use down to the Distribution Network level.

Flexible AC Transmission Systems FACTS devices have the ability to provide precise electronic control to elements of EHV transmission networks and can be used to provide dynamic voltage support, improve system damping and control power flow across networks. Such control allows the engineering design margins of EHV networks to be optimised and provides the ability to increase the power transfer capability up towards the thermal limits of the network.

FACTS devices are often installed on existing networks in response to increased loadings and as a means to defer major capital expenditure such as for new transmission lines. They are also increasingly being incorporated into new networks as an integral element in order to minimise initial capital outlay. In many cases, the EHV networks could not be operated at their existing loading levels without the use of FACTS devices.

In terms of a Modern Engineering Equivalent (MEE) network design, FACTS devices can be seen in two lights:

- A smaller, lower cost MEE might be selectable today after considering the optimised asset including the cost of the FACTS devices.
- On the other hand, FACTS devices allow the utilisation of the existing network to be increased and approach the thermal limits of operation.

The extent to which each of these views is appropriate depends on the particulars of the network and the nature of the network limitations or constraints, vis on the experience and judgement of the practitioner.

A.2.6 Changes in reactive power technology

Over the last 30 years there has been a worldwide trend to increasing utilisation of existing EHV networks. One consequence of this is the rapidly increasing need for reactive power located close to the load centre. The reactive power is required to maximise power transfers without either violating voltage constraints or threatening system security by voltage collapse. Shunt Capacitor technology has improved to the extent that capacitor banks can be connected directly to the EHV busbar. EHV shunt capacitors can provide the reactive power and voltage support required by EHV networks and they can be located close to the load centres. When combined with SCADA technology, the automated switching of these capacitors can optimise losses and improve system security.

A.3 Other changes – Demand Side Management (DSM)

Transmission networks are generally designed to meet the expected Maximum Demand (MD). However examination of load duration data shows that loads above 90% of MD typically occur for only 1-2% of the time on some assets. There is thus a disproportionate investment in network capacity to support a maximum demand that occurs for such a limited period of time. Techniques aimed at minimising the ‘peakiness’ of the maximum loads are referred to as Demand Side Management (DSM).

There is growing regulatory interest in non-network solutions to meeting supply, including DSM. With the exception of ripple control for hot water loads, there has been little success to date in implementing widespread DSM techniques. The reasons for this are not part of this review.

Options for DSM vary widely and can include the following:

- One-way communication to switch off selected loads (eg Ripple control for Hot Water systems).
- Dynamic tariffs with a cost penalty for energy used at times of high demand.
- Distributed load control using simple two-way communication technology to switch selected loads. This could include large customer loads, small customer loads and even individual households.
- Load reduction contracts with major customers in return for tariff relief.

The costs for DSM have not been established and vary widely depending on the sophistication of the proposed schemes. Using DSM to provide a “peak-lopping” service could impact significantly on network optimisation. If the peak demand is reduced then clearly there will be “excess” capacity in an optimisation sense.

In an ODRC valuation however the network loadings are taken as an input parameter in the analysis and a network would not be valued with consideration of potential DSM opportunities included.

If DSM does ever become widely utilised it would be reflected in the load growth allowances in the network design. Given the largely sunk-cost nature of the electricity industry DSM would, if implemented in an economically efficient manner, be unlikely to result in a reduction in present loading of the network and hence its impact on an ODRC valuation would be small.

A.4 Impact on costs

A.4.1 MEE practice

General practice in ODRC valuations has been to consider the overall functionality of network elements, in addition to functionality from a purely "electrical" perspective. For example, from an electrical perspective an underground cable and overhead line might be considered to provide similar functionality, they present different characteristics to the community.

Similarly, the general practice in ODRC valuations has been to consider that the functionality provided by GIS (in greatly reduced footprint for example), is different to that provided by conventional air insulated outdoor switchgear. Thus, where the higher cost of GIS was considered justified on technical grounds the MEE would be taken as GIS. Otherwise the lower cost of conventional switchgear would be allowed despite that a new greenfields installation in a similar location might require GIS under a current community (town planning approvals) requirement.

This is discussed further in Section 5 of this paper.

A.4.2 Impact on costs

Some of the new technologies that have been deployed over the last few decades have provided increased electrical functionality. These have included SCADA, FACTS and reactive power control technologies. These technologies have greatly facilitated the increased utilisation of the principal network elements (lines and substation plant). Less of these principal elements are required to deliver a given electrical capacity to customers, and hence the overall ODRC per MW capacity is lower as a result.

Other technologies such as the availability of underground cable and compact switchgear have provided an opportunity for additional functionality, not to electrical network itself but rather to the community. They do however incur higher costs than traditional counterparts (if easement and land acquisition costs are excluded).

In this regard it could be said that the technology has made available additional functionality which costs more, but in some cases the community values sufficiently highly to require its utilisation.

A.5 Future technological changes

A.5.1 General considerations

There is a low probability for technological "breakthroughs" in transmission networks for the foreseeable future. Instead, we expect there is likely to be a trend towards increasing use of the technologies already available in order to make maximum use of the existing networks and/or to reduce the service costs of the existing assets (operations, maintenance and refurbishment/replacement). As the use of these technologies becomes more widespread, the cost of these technologies is expected to reduce but this is felt likely to be over several years rather than suddenly.

The development timetable for new technologies in the industry, from conception to commercial availability to proven commercially is over several years. With respect to extending the functionality of existing assets, the large cost savings that can be achieved by deferring EHV transmission works and the ever-increasing pressure on existing facilities will drive industry take-up. With load growth rates of only 1 to 2% per year however in mature networks the penetration rate of new technology is still modest.

The ODRC process assumes a complete optimisation using MEE (ie current proven commercially technology) alternatives. The new technologies are reflected in the MEE database costs when they reach this commercially proven status and again this is expected to occur over several years rather than instantaneously.

A.5.2 Future Trends

There are a number of trends that can be identified for the foreseeable future:

- **Increased use of indoor construction for EHV installations in urban environments.** This would be driven by community concerns about noise, EMF issues, visual impact and site constraints. Widespread use of indoor construction will tend to increase costs.
- **Increased use of underground cables for EHV transmission.** We expect this will be driven by difficulties with easement congestion and/or easement acquisition. Increased use of EHV cables will lead to increased costs.
- **Increased use of embedded generation closer to the load centres**. Embedded generation will tend to reduce reliance on transmission networks, however it is doubtful whether the need for transmission networks can be eliminated. Issues with gas infrastructure, in terms of both pipeline capacity and geographic extent, will impact on the take-up of embedded generation (and the possibility of distributed fuel cells). Environmental issues associated with emission levels in urban areas may also constrain the widespread use of embedded generation.
- **Increased use of renewable energy sources (wind and solar) at sites remote from the load centres.** In general, renewable energy sites are not closely aligned with existing EHV networks. Such energy sources will therefore require additional transmission infrastructure to connect into the existing networks. In addition, there is a risk that such generation will significantly distort the expected flows on the transmission networks. Such distortion could lead to a requirement for "deep" network augmentation or alternatively a significant reduction in existing network flows. Either way there is likely to be an impact on the optimisation of the network. However, the utilisation factor may be relatively low in comparison to transmission networks dedicated to "base load" generation.
- **Use of Demand Side Management to provide a "peak-lopping" service.** As the costs for supplying the very short period of maximum demand increase, we expect there will be increasing drivers for the use of Demand Side Management (DSM) options. Use of DSM to provide a "peak-lopping" service could impact on network optimisation via the allowance for future load growth in the optimised design. If the projected peak demand at the end of the allowance period (eg 10 years) is reduced, then there will be "excess" capacity in an optimisation sense. The costs for DSM itself have not been established and vary widely depending on the sophistication of the proposed schemes.

If the network owner sponsors a DSM project in order to obviate a requirement for a transmission upgrade then the cost of this sponsorship (if done as a lump sum) would somehow need to be handled within an ODRC calculation.

- **Increased penetration of DC technology.** Reduced costs of Direct Current (DC) hardware will increase the number of applications where such technology could be economically as well as technically viable. Areas of possible application include point-to-point transmission into a weak network, transmission in areas where there are fault level constraints and as controlled interconnectors as are already being seen in the NEM. This technology is anticipated to be opportunistically deployed and is not readily suitable for widespread substitution within the meshed network.

A.5.3 Long Term Trends

It is difficult to make meaningful predictions about electricity transmission network requirements for the longer term. Potential long-term technologies such as high temperature **superconductor** technology, distributed **fuel cell** technology, large-scale **renewable energy** technology, **nuclear fission** technology are all potentially on or over the horizon and could all impact, in different ways, on the EHV transmission networks over the very long term.

Should the mitigating efforts against greenhouse gas emissions, or the depletion of or inability to use fuel reserves, result in marked changes in the generation sector and the distribution of generators relative to loads, then this would have a major impact on any ODRC valuation.

In general terms, gas fired generation might be utilised closer to load centres than coal fired generation whereas on the other hand renewables generators are often farther away.

A.6 Impact on a generic transmission business – "brown field" basis.

Bearing the above factors in mind, a generic transmission business, facing a "brown field" development, would most likely require the following:

- All EHV lines to be placed underground in urbanised area. A new transmission line would typically require 20-30km of undergrounding before reaching a less developed environment allowing use of cheaper overhead lines.
- EHV stations to be indoors in urban areas.
- All HV exits (132kV to 66kV) to be undergrounded.
- EHV capacitor banks to be installed as standard.
- Fibre optic communication facilities to be installed as standard.

As a consequence of these factors, we expect the cost of 'bypass' assets might become dearer than existing network historic costs because of the impact of external constraints making new EHV installations in urban/CBD areas difficult. Such an outcome counters the trend to lower costs due to cheaper raw materials and labour productivity gains.

On this basis, a re-ODRC of assets in the future could be expected result in a dearer outcome (in real terms) than historically for urban/CBD assets and a cheaper outcome for rural assets. Over time, these differences will compound and become significant.

A.7 CAPEX Uncertainty

There are numerous sources of uncertainty when estimating Capex requirements. Listed below are some of the elements that contribute to this uncertainty.

1. Unit Price (differences between suppliers+/-10%)
2. Timing (staged development? – marginal costs of partial development higher)
3. Growth (magnitude and geographic/regional) and the allowance for future growth incorporated into the optimisation process
4. Changed circumstances facing the network (historical development)
5. Network Limitations other than capacity (Voltage Collapse, Stability etc)
6. Finance/Interest Rates
7. Type of technology employed
8. Non-network alternatives (Generation, Demand Side Management)
9. Risk Tolerance of Transmission Network Service Provider (including changes over time)
10. Electricity Planning Criteria (N-1 vs N-r)
11. Level of detail in the asset register and the extent to which the valuation considers actual site conditions at each asset not described in the asset register. The level of documentation available to support the valuation
12. Community expectations (EMF, Noise, Visual, Reliability, Quality of Supply)
13. Regulatory environment (WACC variation over time)
14. Energy Sources – potentially different locations (Coal vs Gas vs Wind)
15. Supply Reliability equation - Plant Utilisation Factors vs Redundancy/Reliability
16. Changes in Load profile (eg change from Winter heating peak to Summer airconditioning peak)
17. Operations and maintenance costs (trade-off between capital cost and future opex cost), value engineering analyses might justify higher capex in return for reduced operations or maintenance costs
18. Detailed design considerations may change costs
19. Systematic errors in ORDC methodology
20. MEE registers lagged in time and based on historic costs rather than point-in-time valuation
21. Impact of commodity prices on materials such as Copper, Steel, Aluminium
22. Impact of exchange rates on imported high technology equipment
23. The difficulty of matching regional construction cost factors to the actual geographic distribution of the asset being valued

Appendix B National Electricity Code extracts

The following extracts are from the NEC[17]:

Part B Regulation of Transmission Revenue Requirement

6.2 General Principles Governing Regulation of Transmission Revenue

This Code does not limit or prescribe the methodologies to be applied by the ACCC in exercising its regulatory powers under the Trade Practices Act and this Code, except to the extent that those methodologies must be consistent with the objectives, principles, broad forms and mechanisms, and information disclosure requirements described in clauses 6.2.2 to 6.2.6 inclusive of this Code.

6.2.1 National regulatory arrangements

(a) The arrangements specified in this Part B governing the economic regulation of transmission revenue in the market are to commence on:

(1) 1 July 1999 in New South Wales;
(2) 1 January 2001 in Victoria;
(3) 1 July 1999 in the Australian Capital Territory;
(4) 1 January 2001 in South Australia; and
(5) 1 July 1999 in Queensland,

which date in respect of each respective participating jurisdiction and for the purpose of this clause 6.2.1 is to be called "the transmission regulation commencement date".

(6) Clause 6.2.1(a) must be read and construed subject to Chapter 9;
(7) This clause 6.2.1(a) is a protected provision;
(8) Nothing in this clause 6.2.1(a) is to be read or construed as limiting the validity, force or effect of a derogation in Chapter 9 in respect of a participating jurisdiction and any derogation in Chapter 9 which is intended to modify, vary or exempt a provision of clause 6.2.1(a) is deemed to prevail over that provision of clause 6.2.1(a) in respect of the participating jurisdiction to which the derogation applies.

(b) On the applicable transmission regulation commencement date the ACCC is to become the authority responsible for regulation of transmission network service pricing in the market in respect of each participating jurisdiction.

(c) For the period prior to the applicable transmission regulation commencement date each participating jurisdiction must appoint a Jurisdictional Regulator to be responsible for the regulation of transmission service pricing within its respective jurisdiction.

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(d) Subject to the agreement of the ACCC and the relevant Jurisdictional Regulator, those portions of the transmission network operating at voltages of between 132 kV and 66 kV that do not operate in parallel with and provide support to the higher voltage network may be deemed by the Network Service Provider to be subject to the regulatory arrangements for distribution service pricing set out in Parts D and E of this Code. In deciding on the assets to be covered by distribution service pricing regulation consideration must be given to the practical desirability of aligning changes in regulatory coverage to changes in asset ownership wherever feasible.

(e) Interim jurisdictional regulatory arrangements for transmission service pricing are specified in Chapter 9 of the Code.

(f) Notwithstanding the establishment of an interim transmission service pricing regulatory regime to apply during the period prior to the applicable transmission regulation commencement date in any participating jurisdiction, any Government may agree with the ACCC to transfer responsibility for administration of that regulatory regime to the ACCC prior to the applicable transmission regulation commencement date.

6.2.2 Objectives of the transmission revenue regulatory regime to be administered by the ACCC

The transmission revenue regulatory regime to be administered by the ACCC pursuant to this Code must seek to achieve the following outcomes:

(a) an efficient and cost-effective regulatory environment;

(b) an incentive-based regulatory regime which:

 (1) provides an equitable allocation between Transmission Network Users and Transmission Network Owners and/or Transmission Network Service Providers (as appropriate) of efficiency gains reasonably expected by the ACCC to be achievable by the Transmission Network Owners and/or Transmission Network Service Providers (as appropriate); and

 (2) provides for, on a prospective basis, a sustainable commercial revenue stream which includes a fair and reasonable rate of return to Transmission Network Owners and/or Transmission Network Service Providers (as appropriate) on efficient investment, given efficient operating and maintenance practices of the Transmission Network Owners and/or Transmission Network Service Providers (as appropriate);

(c) prevention of monopoly rent extraction by Transmission Network Owners and/or Transmission Network Service Providers (as appropriate);

(d) an environment which fosters an efficient level of investment within the transmission sector, and upstream and downstream of the transmission sector;

(e) an environment which fosters efficient operating and maintenance practices within the transmission sector;

(f) an environment which fosters efficient use of existing infrastructure;

(g) reasonable recognition of pre-existing policies of governments regarding transmission asset values, revenue paths and prices;

(h) promotion of competition in upstream and downstream markets and promotion of competition in the provision of network services where economically feasible;

(i) reasonable regulatory accountability through transparency and public disclosure of regulatory processes and the basis of regulatory decisions;

(j) reasonable certainty and consistency over time of the outcomes of regulatory processes, recognising the adaptive capacities of Code Participants in the provision and use of transmission network assets;

(k) reasonable and well defined regulatory discretion which permits an acceptable balancing of the interests of Transmission Network Owners and/or Transmission Network Service Providers (as appropriate), Transmission Network Users and the public interest as required of the ACCC under the provisions of Part IIIA of the Trade Practices Act.

6.2.3 Principles for regulation of transmission aggregate revenue

The regime under which the revenues of Transmission Network Owners and/or Transmission Network Service Providers (as appropriate) are to be regulated is to be administered by the ACCC from 1 July 1999 in accordance with the following principles:

(a) Concerns over monopoly pricing in respect of the transmission network will, wherever possible and practicable, be addressed through the introduction of competition in the provision of transmission services.

(b) Where pro-competitive and structural reforms alone are not a practicable or adequate means of addressing the problems of monopoly pricing in respect of the transmission network or protecting the interests of Transmission Network Users, the form of economic regulation applied is to be revenue capping.

(c) The ACCC is responsible for determining whether sufficient competition exists to warrant the application of a regulatory approach which is more "light-handed" than revenue capping, and if so, the form of that regulation.

(d) The regulatory regime to be administered by the ACCC must be consistent with the objectives outlined in clause 6.2.2 and must also have regard to the need to:

> (1) provide Transmission Network Owners and/or Transmission Network Service Providers (as appropriate) with incentives and reasonable opportunities to increase efficiency;
>
> (2) create an environment in which generation, energy storage, demand side options and network augmentation options are given due and reasonable consideration;

(3) take account of and be consistent with the allocation of risk where this has been agreed between Transmission Network Owners and/or Transmission Network Service Providers (as appropriate) and Transmission Network Users;

(4) provide a fair and reasonable risk-adjusted cash flow rate of return to Transmission Network Owners and/or Transmission Network Service Providers (as appropriate) on efficient investment given efficient operating and maintenance practices on the part of the Transmission Network Owners and/or Transmission Network Service Providers (as appropriate) where:

(i) assets created at any time under a take or pay contract are valued in a manner consistent with the provisions of that contract;

(ii) assets created at any time under a network augmentation determination made by NEMMCO under clause 5.6.5 are valued in a manner which is consistent with that determination;

(iii) subject to clauses 6.2.3(d)(4)(i) and (ii), assets (also known as "sunk assets") in existence and generally in service on 1 July 1999 are valued at the value determined by the Jurisdictional Regulator or consistent with the regulatory asset base established in the participating jurisdiction provided that the value of these existing assets must not exceed the deprival value of the assets and the ACCC may require the opening asset values to be independently verified through a process agreed to by the National Competition Commission;

(iv) subject to clauses 6.2.3(d)(4)(i) and (ii), valuation of assets brought into service after 1 July 1999 ("new assets"), any subsequent revaluation of any new assets and any subsequent revaluation of assets existing and generally in service on 1 July 1999 is to be undertaken on a basis to be determined by the ACCC and in determining the basis of asset valuation to be used, the ACCC must have regard to:

A the agreement of the Council of Australian Governments of 19 August 1994, that deprival value should be the preferred approach to valuing network assets;

B any subsequent decisions of the Council of Australian Governments; and

C such other matters reasonably required to ensure consistency with the objectives specified in clause 6.2.2; and

(v) benchmark returns to be established by the ACCC are to be consistent with the method of valuation of new assets and revaluation, if any, of existing assets and consistent with achievement of a commercial economic return on efficient investment;

(5) provide reasonable certainty and consistency over time of the outcomes of regulatory processes having regard for:

(i) the need to balance the interests of Transmission Network Users and Transmission Network Owners and/or Transmission Network Service Providers (as appropriate);

(ii) the capital intensive nature of the transmission sector, the relatively long lives of transmission assets, and the large and relatively infrequent augmentation of the transmission network;

(iii) the need to minimise the economic cost of regulatory actions and uncertainty;

(iv) relevant previous regulatory decisions made by authorised persons including:

A the initial revenue setting and asset valuation decisions made by participating jurisdictions in the context of industry reform pursuant to the Competition Principles Agreement;

B decisions made by ministers under Commonwealth, State or Territorial legislation;

C decisions made by Jurisdictional Regulators; and

D decisions made by the ACCC.

6.2.4 Form and mechanism of economic regulation

(a) Economic regulation is to be of the CPI minus X form, or some incentive-based variant of the CPI minus X form which is consistent with the objectives and principles outlined in clauses 6.2.2 and 6.2.3.

(b) In applying the form of economic regulation specified in clause 6.2.4(a), the ACCC is to set a revenue cap to apply to each Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) for the regulatory control period which is to be a period of not less than 5 years.

A description of the process and timetable for re-setting the revenue cap must be published by the ACCC at a time which provides all affected parties with adequate notice to prepare for, participate in, and respond to that process, prior to the commencement of the regulatory control period to which that revenue cap is to apply. The revenue cap re-setting process must provide all affected parties with a reasonable opportunity to prepare for, participate in, and respond to that process.

(c) In setting a separate revenue cap to be applied to each Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) in accordance with clause 6.2.4(b), the ACCC must take into account the revenue requirements of each Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) during the regulatory control period, having regard for:

(1) the demand growth which the Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) is expected to service;

(2) the service standards referred to in the Code applicable to the Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) and any other standards imposed on the Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) by agreement with the relevant Network Users;

(3) the ACCC's reasonable judgment of the potential for efficiency gains to be realised by the Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) in expected operating, maintenance and capital costs, taking into account the expected demand growth and service standards referred to in clauses 6.2.4(c)(1) and (2);

(4) the weighted average cost of capital of the Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) applicable to the relevant network service, having regard to the risk adjusted cash flow rate of return required by investors in commercial enterprises facing similar business risks to those faced by the Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) in the provision of that network service;

(5) the provision of a fair and reasonable risk-adjusted cash flow rate of return on efficient investment including sunk assets subject to the provisions of clause 6.2.3(d)(4);

(6) any State, Territorial and Commonwealth taxes (or State or Territorial equivalent of Commonwealth taxes) paid by the Transmission Network Owner or Transmission Network Service Provider (as appropriate) in connection with the provision of transmission services;

(7) payments to any Generators providing network support services in accordance with clause 5.6.2;

(8) the on-going commercial viability of the transmission industry; and

(9) any other relevant financial indicators.

(d) Notwithstanding clause 6.2.4(b), the ACCC may revoke a revenue cap during a regulatory control period only where it appears to the ACCC that:

(1) the revenue cap was set on the basis of false or materially misleading information provided to the ACCC;

(2) there was a material error in the setting of the revenue cap and the prior written consent of parties affected by any proposed subsequent re-opening of the revenue cap has been obtained by the ACCC; or

(3) there is a substantial change in ownership of network assets within the business of the Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) which, in the opinion of the ACCC, may lead to a material change in the revenue requirement of the Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) following that change in ownership.

(e) If the ACCC revokes a revenue cap under clause 6.2.4(d), then the ACCC may make a new revenue cap in substitution for the revoked revenue cap to apply for the remainder of the regulatory control period for which the revoked revenue cap was to apply.

(f) Revenue caps set by the ACCC are to apply only to those services, the provision of which in the opinion of the ACCC are not reasonably expected to be offered on a contestable basis.

Part C Transmission pricing

This part of the Code is subject to the review to be undertaken by NECA required by clause 6.1.6 of the Code and is to apply only for so long as the ACCC has not approved such modifications, as may be recommended by NECA under clause 6.1.6(g) of the Code.

This part of the Code describes the pricing requirements applying to transmission networks and their associated connection assets. The arrangements in this Part C will commence in a participating jurisdiction when the arrangements in Part B commence.

The diagram on the following page illustrates the relationship between various classes of transmission service, and method of cost recovery and pricing.

6.3 Step 1 - Allocation of Aggregate Annual Revenue Requirement

The aggregate annual revenue requirement of a Transmission Network Owner for year t is an amount not exceeding the sum of the following elements:

(a) the maximum allowed revenue for provision of revenue capped transmission services for year t as determined by the Regulator in accordance with clause 6.2.4; and
(b) the annual revenue requirement associated with contestable transmission services for year t provided by the Transmission Network Owner as defined in clause 6.2.4(f).

The aggregate annual revenue requirement of a Transmission Network Owner must be divided between classes of transmission service to provide an amount being the aggregate annual revenue requirement for year t for each class of transmission service provided by the Transmission Network Owner.

6.3.1 Determining annual revenue requirement for classes of transmission service
...
6.3.2 Multiple Transmission Network Owners within a region
...
6.3.3 Single Transmission Network Owner in a region
...
6.3.4 Allocation over several regions
...

6.4 Step 2 - Allocation of Transmission Costs

This clause sets out the procedure to be used for allocation of the aggregate annual revenue requirement amongst all assets of the Transmission Network Owner utilised in the provision of transmission services which will then provide a figure estimating the cost of providing those transmission services. This process is called "cost allocation".

6.4.1 Cost allocation to individual transmission system assets

(a) Any asset which is required by the Transmission Network Owner to deliver the transmission services to a standard described in schedule 5.1 is classified as one or more of the following in accordance with schedule 6.2:

(1) entry service asset;
(2) exit service asset; and
(3) use of transmission use of system service asset.

(b) A Transmission Network Owner's aggregate annual revenue requirement for each of the classes of transmission service described in clause 6.3.1(a)(1), (2) and (3) is allocated among the assets classified in the corresponding class of assets described in clause 6.4.1(a).

(c) The allocation in clause 6.4.1(b) to each asset in the class is:

$$AAR_{ij} = \frac{AARR_j \times ORC_{ij}}{\Sigma_j ORC_{ij}}$$

where:

ARRij is the annual revenue requirement for the asset in the particular class.
AARRj is the aggregate annual revenue requirement for the class of transmission service.
ORCij is the optimised replacement cost (undepreciated value) of the specified asset/s;
i is the individual asset; and
j is the class of asset as defined in clause 6.4.1(a). (ie: j = 1, 2, or 3),

and the amount allocated to an asset is the annual aggregate revenue requirement for that asset.

6.5 Step 3 - Transmission Service Prices

The outcome of the cost allocation process specified in clause 6.4 is an allocated annual cost referable to one or more of the following cost categories for each connection point with a Network User connected to a transmission network (depending on the type of Network User receiving transmission service at that connection point):

(a) entry cost;
(b) exit cost;
(c) Generator use of system cost;
(d) Transmission Customer use of system cost; and
(e) Transmission Customer common service cost.

These categories of cost must be converted into usage based prices in accordance with clauses 6.5.1 to 6.5.5.

6.5.1 Entry price
...
6.5.2 Transmission Customer exit price
...
6.5.3 Generator use of system price
...
6.5.4 Customer use of system price
...
6.5.5 Cost allocation for the new regulatory control period

a) The prices resulting from the cost allocation of the transmission network to an individual connection point for the new regulatory control period must be limited so that they do not result in a change of more than 2% per annum in the Transmission Customer use of system price relative to the average Transmission Customer use of system price for the region.

(b) The restriction on prices referred to in clause 6.5.5(a) is applied by expressing the cost allocated to each individual connection point as a price based on the usage quantity for which the greatest proportion of network charges is derived for the particular network.

(c) Where the limit referred to in clause 6.5.5(a) is exceeded at any connection point the excess must be added to the amount of the aggregate annual revenue requirement for the common services class of transmission service for the relevant year of the regulatory control period.

(d) Any excess or deficit removed under clause 6.5.5(c) must be re-introduced to the allocated cost for transmission network use of system service calculations for years 2, 3, 4 and 5 of the regulatory control period, subject to any further adjustment under clause 6.5.5(c) to be consistent with the requirement of maintaining the maximum Transmission Customer use of system price change relative to the average at 2% per annum.