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Handbook for Optimised Deprival Valuation of System Fixed Assets of Electricity Line Businesses

Energy Markets Regulation Unit
Energy Markets Information and Services Group
Resources and Networks Branch
Ministry of Commerce
Wellington

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ABBREVIATIONS USED IN THE HANDBOOK

Abbreviation	**Term**
a	Stranded aluminium conductor
Al	Aluminium
c	Stranded copper conductor
CAPM	Capital Asset Pricing Model
Cu	Copper
DRC	Depreciated Replacement Cost
DV	Depreciated Value
EBIT	Earnings Before Interest and Tax
ELB	Electricity Line Business
EV	Economic Value
FCF	Free Cash Flow
h	HDPE sheath
hc	Helically wound copper screen
HV	High Voltage
kV	kiloVolt
kVA	kiloVoltAmpere
kWh	kiloWatt hour
LV	Low Voltage
MEA	Modern Equivalent Assets
MV	Medium Voltage
MW	MegaWatt
NOPAT	Net Operating Profit after Tax
NPV	Net Present Value
NRV	Net Residual Value
NSV	Net Saleable Value
ODRC	Optimised Depreciated Replacement Cost
ODV	Optimised Deprival Value
ORC	Optimised Replacement Cost
PV	Present Value
Regulations	Electricity (Information Disclosure) Regulations 1999
RC	Replacement Cost
RL	Remaining Life
RV	Residual Value
SWER	Single Wire Earth Return
TL	Total Life
UDV	Undepreciated Value
WACC	Weighted Average Cost of Capital
x	XLPE insulation

PREFACE

Purpose of the Handbook

1 This handbook has been published by the Secretary of Commerce pursuant to section 170(1)(g)(i) of the Electricity Act 1992 for the single purpose of providing the methodology to be adopted in valuing the system fixed assets of Electricity Lines Businesses (ELBs), as defined by the Electricity (Information Disclosure) Regulations 1999 to support the disclosure of performance measures under Regulation 15 of the Electricity (Information Disclosure) Regulations 1999 (the regulations).

2 This edition of the Optimised Deprival Valuation (ODV) handbook supersedes both the Handbook for Optimised Deprival Valuation of Transpower dated 7 July 1994, and the Handbook for Optimised Deprival Valuation of Electricity Line Businesses dated 28 May 1998.

Coverage of the Handbook

3 The handbook covers the valuation of system fixed assets using the ODV methodology. The handbook does not cover the valuation of non-system assets that ELBs may own.

Defining the Valuer(s)

4 For the purposes of this handbook, the term Valuer(s) refers to any party (or parties) responsible for the preparation of all or any part of the valuation.

Frequency of Preparation of ODVs

5 The regulations require ELBs to complete a valuation based on the ODV methodology at least every three years or whenever there is a cumulative increase or decrease of 10% or more in the capacity of the electricity system (as measured in system length or transformer capacity) since the last ODV, whichever occurs first. The valuation must be carried out as at a specific date. ELBs may undertake valuations on a more frequent basis if desired. The most recently completed and certified valuation must be used in the calculation of the financial performance measures required to be disclosed under the regulations.

Disclosure of ODV Reports

6 The regulations require all ELBs to disclose annually the value of their system fixed assets and make a valuation report available to the general public for inspection. The valuation report must disclose the following information in relation to the methodology used:

(a) the asset replacement costs and lives used, the quantity of assets in each category of assset replacement costs and lives used, and the replacement cost of the network; and
(b) details of the amount of depreciation charged, and the depreciated replacement cost of the network; and
(c) details of the components of the network which were optimised, and the optimised depreciated replacement cost of the network; and
(d) details of the comparison of the optimised depreciated replacement cost with economic value for those parts of the network which may not be able to sustain tariffs based on optimised depreciated replacement cost (including any specific assumptions used for the purpose of calculating the economic value of that part of the network).

7 Form 7 being the certificate related to ODV Valuation Reports of electricity line busineses including Transpower must include, inter alia, the Optimised Depreciated Replacement Cost (ODRC), the Optimised Deprival Valuation (ODV), and the valuation of the line business assets, including the system and non-system fixed assets and net working capital.

Tariff Setting

8 Tariff setting is an independent process from preparation of ODVs. There is specifically no regulatory requirement that prices be determined on the basis of system assets being valued according to ODV.

General

9 The handbook has been prepared by the Energy Markets Regulation Unit (EMRU) within the Resources and Networks Branch of the Ministry of Commerce. ELBs encountering problems with the handbook are welcome to discuss issues arising with the EMRU. The Ministry of Commerce will monitor the application of the handbook, with a view to subsequent modification in the light of experience.

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PART ONE: INTRODUCTION

1.1 This handbook has two principal sections:

- Part Two: General Overview of the ODV Valuation Approach
- Part Three: Practical Valuation and Mandatory Procedures

1.2 Part Two gives a general description of the approach to valuing system fixed assets using the Optimised Deprival Valuation (ODV) methodology, while Part Three (which is supported by a series of appendices) gives the details of the practical approach which must be applied to valuation. It is mandatory that Part Three be followed in carrying out valuations for the purposes of complying with the Electricity (Information Disclosure) Regulations 1994. Following Part Two alone would not constitute compliance with the regulations.

PART TWO: GENERAL OVERVIEW OF THE ODV VALUATION APPROACH

Introduction

2.1 The mandatory valuation approach set out in Part Three is based on the application of the Optimised Deprival Value (ODV) methodology. The approach applies to both local line businesses and to Transpower.

2.2 The aim of applying the ODV methodology is to value the assets at the level at which they can be commercially sustained in the long term, and no more. The resulting value should be equal to the loss to the owner if they were deprived of the assets and then took action to minimise their loss.

2.3 It is recognised that the value of the assets derived in this way may differ from their current book value. Book value is typically based on expenditures made over the years and may bear little resemblance to the ODV value.

The Optimised Deprival Valuation Methodology

2.4 The ODV of system fixed assets is the minimum of Optimised Depreciated Replacement Cost (ODRC) and Economic Value (EV). The ODRC is the replacement cost of the existing system fixed assets which have been optimised from an engineering standpoint and depreciated according to their age. In some cases, because of constraints on tariffs, it may not be possible to make a normal rate of return on segments of the network when the segment assets are valued at ODRC. That is the segment is not self-sustainable in the long term. In such cases the EV value, a value lower than the ODRC, is applicable to the segments. The approach to calculating EVs is described later.

2.5 The ODV methodology involves the following steps:

(a) Calculation of Optimised Depreciated Replacement Cost (ODRC)

(i) preparing a detailed asset register

(ii) calculate the Replacement Cost (RC)

(iii) assessment of depreciation (DRC)

(iv) system optimisation

(v) determination of Optimised Depreciated Replacement Cost (ODRC)

(b) determination of Economic Value (EV)

(c) determination of the ODV as the lesser of the ODRC and the EV.

Optimised Depreciated Replacement Cost (ODRC)

2.6 The ODRC measures the cost of replicating the system in the most efficient way possible, from an engineering perspective, given its service capability and *the age of the existing assets.*

Preparing a Detailed Asset Register

2.7 The basis for undertaking an ODV valuation is the collation of a comprehensive asset register of the ELB's system fixed assets and their configuration. Such asset registers should contain data on the quantity, location, physical condition, age and maintenance of the ELB's assets.

Determination of Replacement Cost (RC)

2.8 The next step is to value the network at replacement cost. The replacement cost is determined as the cost of replacing assets with Modern Equivalent Assets (MEA). It is important that objective values be applied consistently across the industry, and accordingly Part Three prescribes maximum values for assets that are to be used.

Assessment of Depreciation to Determine Depreciated Replacement Cost (DRC)

2.9 Once the quantities and replacement costs of assets have been determined, costs need to be depreciated in cases when the existing asset's remaining life is less than the life expected from a new asset. The depreciation recognises the limited Remaining Life (RL).

2.10 The RL of an asset can be determined as the (Total Life (TL) – Age of Asset). Part Three prescribes maximum TLs for assets that are to be used. This is done to prevent aged assets being over-valued.

System Optimisation

2.11 Optimisation attempts to answer the question:

Given the required level of service, in terms of capacity and quality of supply, what is the most cost-effective set of assets to achieve that supply?

2.12 The idea of optimisation is to determine a value of system fixed assets that is the counterpart to the market value of the assets of a business in a competitive market – that is the value of the assets on which such a business could earn a normal rate of return commensurate with the risk that business faces.

2.13 Optimisation consists of determining an appropriate network configuration and appropriate design and rating of sub-systems or segments of the network taking into account factors such as usage, likely future usage and security of supply, as well as the assets already in place. In theory, in considering re-configuration it would be possible to consider the "green fields" design of an entirely new network. In practice such an exercise would generally not be warranted, because of the time and cost involved, and because of the constraints imposed by factors such as the given positions of points of supply and historical supply authority boundaries.

2.14 It should be stressed that optimisation is not concerned with improving the system from its current state. The system should not be notionally re-designed to be better than it is (whether in terms of capacity, or other standards) where this would cost more. Optimisation leads only to reductions in the cost of the system for valuation purposes.

2.15 Economies of scale in larger systems will be reflected automatically in the valuation through the configuration of the optimal network.

2.16 Where optimisation has taken place there is the question of what depreciation to apply to the notional replacement assets. Part Three specifies that the notional replacement assets be depreciated assuming that they have the same proportion of their TL remaining as do the assets they are replacing.

Determination of Optimised Depreciated Replacement Cost (ODRC)

2.17 To determine the Optimised Depreciated Replacement Cost it is necessary to exclude from the valuation those network assets which have been optimised and include the modern equivalent optimised depreciated assets.

ECONOMIC VALUE (EV)

When to Apply

2.18 EVs are applied to assets that are worth less than their ODRC. This occurs when the maximum revenue that the lines in a network segment can earn, less capital and operating expenditure required to maintain the lines in the long run, would be insufficient to give a normal rate of return on the segment assets valued at ODRC. The maximum revenue is determined from assessing the maximum long run sustainable tariffs, with these being those at a level such that with any higher tariff the consumers would disconnect. It is most likely to be in rural areas with remote, lengthy lines that EVs will be applicable to network segments.

How to Determine the EV Value

2.19 When current line connections are not economically sustainable, without any externally imposed constraint, ELBs have the incentive to remove these connections in due course. At the time of such removal, the value of the connections, that is the EV, is the Net Realisable Value (NRV) of the assets.

2.20 However, ELBs (except Transpower) are subject to the constraint imposed by the Electricity Act 1992 for all existing line connections to be maintained until 2013, unless consumers agree to disconnection. Thus unless an ELB (except Transpower) believes it can gain the agreement of its consumers to disconnect, the earliest it can value the assets at NRV is 2013.

2.21 The EV is in theory therefore the Present Value (PV) of the maximum revenue the network segment can earn, less capital and operating expenditure, in order to maintain the segment up to disconnection plus the PV of the NRV at the prospective time of disconnection.

2.22 It should be noted that the expenditure required to maintain the segment in the period to disconnection would generally be less than that required in the alternative case in which the segment was kept operating in the long run with no disconnection.

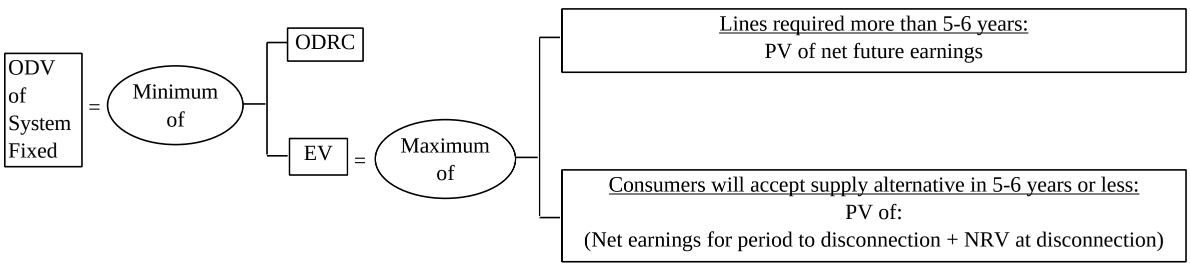
2.23 Part Three allows that, unless disconnection is envisaged within the next 5 to 6 years, given the discounting effect inherent in PV calculations, a satisfactory approach is to calculate the EV under the assumption that the network segment will be required to be sustained in perpetuity.

Putting ODRCs and EVs Together

2.24 As indicated above the ODV of the system fixed assets is the minimum of the ODRC and the EV. Figure 2.1 summarises how the decisions for determining EV and making the choice between EV and ODRC, discussed in the preceding paragraphs, fit together.

2.25 The decisions between ODRC and EV have to be made on a network segment basis. The overall system ODV is determined by the aggregation of the ODRCs for those segments to which an ODRC valuation is applicable, and the EVs for those segments for which an EV valuation is applicable.

FIGURE 2.1 DETERMINATION OF ODV



PART THREE: PRACTICAL VALUATION AND MANDATORY PROCEDURES

Introduction

3.1 The valuation procedures presented here in Part Three differ from those given in Part Two in that more steps are included. This is in recognition of both the practicalities of undertaking valuations and the requirements of regulation 20 of the Electricity (Information Disclosure) Regulations 1999.

3.2 Regulation 20, and Form 7 require, among other things, that the following items be disclosed in valuation reports and/or the certificates which must accompany ODV and valuation disclosures:

(i) replacement cost of the network

(ii) depreciated replacement cost of the network

(iii) optimised depreciated replacement cost of the network

(iv) ODV of the network.

3.3 Disclosure of the individual items listed in paragraph 3.2 is designed to provide for transparency of the valuation process carried out by individual ELBs by making clear the effect of both optimisation and the application of EVs on the final ODV valuation.

Valuation of the System Fixed Assets at Replacement Cost (RC)

3.4 There are two steps in the determination of replacement cost:

(i) preparing a detailed asset register

(ii) valuing the assets.

Preparing a Detailed Asset Register

3.5 All ELBs should have a comprehensive database for their assets. Ideally, for the purposes of carrying out optimisation and the application of EVs, the database should be computerized to facilitate sorting and reporting according to various numbers and levels of sort key (eg asset type, voltage level, capacity, network segment or location).

3.6 To be able to carry out adequate optimisation and application of EVs it will generally be necessary that the network register is built up from or can be divided into relatively small segments.

3.7 Appendix A gives the minimum classification of system fixed assets expected to be used by local ELBs.

3.8 As well as system fixed assets, stores and spares of network equipment should be valued as part of the ODV. ELBs should have a record of stores and spares, preferably in a computerised ledger system. In cases where complete records are not kept, or are unreliable, it may be necessary to undertake a stocktake for valuation purposes.

3.9 Asset registers should be checked for consistency and sample checks should be carried out in the field to verify that the quantities and ages recorded are accurate within reasonable limits. Guidance as to what constitutes "reasonable limits" should be taken from the significance of each item and its effect on the accuracy of the overall valuation.

Exclusion of Assets

3.10 Assets such as head office buildings, office furniture and equipment, motor vehicles, tools, plant and machinery, works under construction, and non-network land and stores and spares should not be included in the asset register of system fixed assets that is used as a basis for preparing the ODV valuation of system fixed assets. Also consumers' meters and consumer-based load control relays should be excluded.

Accessibility of Information

3.11 The system fixed asset register should be in a form that facilitates scrutiny of the register and a ready understanding of how it is composed. Spreadsheet presentations are appropriate.

Valuing the Assets

3.12 The system fixed assets are to be valued using the Replacement Costs (RC) of Modern Equivalent Assets (MEA) that would be installed today in order to provide the same level of service as the assets in place. The MEA should not reflect improvements required by legislative changes made since the assets were first built or installed, if such improvements result in higher replacement costs and if the existing assets have not yet had to comply with the additional requirements eg where grandfathering provisions apply. The maximum values for MEA for ELBs which are to be applied are set out in tables in Appendix B. Lower values can be applied but the maxima are not to be exceeded except as provided for in Appendix B. Appendix B also contains other details regarding the valuation of particular types of assets.

3.13 When determining MEA there are indicators that can be used to determine what asset to select for costing. Such indicators include:

(i) number of faults/100km of line/year
(ii) voltage complaints/100km of line/year
(iii) proven reliability of the technology
(iv) functional compliance with modern operating requirements
(v) meeting statutory and industry safety requirements
(vi) least lifetime costs (taking account of all aspects of performance eg losses)

3.14 When the tables in Appendix B do not provide guidance on how to value particular major assets such as switchgear, Valuers should obtain cost estimates from manufacturers or suppliers. Valuers should explicitly identify in the valuation report each asset which does not fall within Appendix B, together with the replacement cost and the total life assumptions which have been used.

3.15 Construction cost estimates should be based on knowledge of the work involved, and on efficient industry practice with competitive costs such as would be charged by private contractors.

3.16 Any grants or contributions that have been received should be ignored as it is the valuation of assets that is required.

3.17 Aggregation of the RCs for all the system fixed assets will produce the network RC as required by regulation 20.

Valuation of the System Fixed Assets at Depreciated Replacement Cost (DRC)

Approach to Depreciation

3.18 Asset replacement costs should be depreciated when the existing asset's remaining service life is less than the life that would normally be expected from a new asset. The depreciation effectively recognises the limited Remaining Life (RL). The MEA costs should be depreciated according to the RLs of the existing assets.

3.19 The straight line method of depreciation should be used such that the Depreciated Value (DV) is determined as:

	DV	=	UDV x RL/TL
where:	UDV	=	Undepreciated Value (ie Replacement Cost (RC))
	RL	=	Remaining life
	TL	=	Total Life.

It is clear from the above that both the Total Life and the Remaining Life need to be assigned for assets.

Determining Asset Total Lives

3.20 The maximum TLs of Modern Equivalent Assets (MEA) which are to be used are set out in the tables in Appendix B. These maxima are not to be exceeded except as provided for in the appendix. The appendix also contains other details regarding the TLs to be used for particular types of assets..

3.21 TLs lower than the specified maxima may be used and may be appropriate in certain circumstances such as specified in Appendix B.

Determining Asset Remaining Lives

3.22 The basic procedure for determining RLs is to subtract the age of assets from their TLs.

3.23 The age of assets should be determined for initial ODV valuations, either from records establishing the age, or where necessary from engineering assessments of the age.

3.24 In cases where engineering assessments of the age have been carried out for one valuation, the age in successive valuations should also be based on that earlier engineering assessment – reassessments of the time of installation of the asset are not allowable.

3.25 In cases where materiality of the value of assets is not an issue, and where data availability and calculation complexity would not warrant the determination of age and RL of individual assets, grouping of assets and the assessment of weighted average RLs is acceptable.

3.26 Appendix B provides procedures for assessing RLs in cases where assets have been refurbished, and in cases where an asset (or group of assets) has reached its TL.

3.27 When an asset may be retired early from service because it may become redundant as part of a development of the system, this should not be taken into account in assessing the RL of that asset. However, when a class of assets is routinely replaced as part of the evolution of the system before its technical life expires, then this should be taken into account in assessing the TL for that class of assets.

Assets with Residual Value

3.28 In some cases assets will have a Residual Value (RV) at the end of their TL, or after allowing for the costs of recovery a Net Residual Value (NRV). When this is the case an adjustment is required to the formula given in 3.19. With the adjustment the Depreciated Value (DV) is determined as:

$$DV = (UDV - NRV) \times RL/TL.$$

3.29 Generally the NRV of ELB fixed system assets, once the cost of recovery is netted off, is low and can be set aside as not of material value.

Determining the Depreciated Replacement Cost (DRC)

3.30 Aggregation of the DVs for all the system fixed assets will produce the network DRC as required by regulation 20.

Optimisation: Valuation of the System Fixed Assets at Optimised Depreciated Replacement Cost (ODRC)

Introduction

3.31 Optimisation of ELBs' system fixed assets should be carried out to ensure that only "used and useful" assets (or elements thereof) are valued. The resulting ODRC valuation should be based on an optimal network, built to modern efficient design, that:

(i) meets the same expected service requirements as the existing network; and

(ii) is depreciated to the same remaining life as the existing network.

3.32 Optimisation consists of three stages:

(i) identifying any stranded assets;

(ii) optimising the system configuration; and

(iii) optimising elements in the system.

Constraints On Optimisation

3.33 The optimisation should be carried out subject to the following constraints.

(i) the security of supply should be assumed to remain at the existing level;

(ii) the location of points of supply should be assumed to be fixed. However,where a point of supply can be by-passed and this allows a saving in ELB assets, then that point of supply should be deleted for valuation purposes;

(iii) the location of customers should be assumed fixed;

(iv) the existing boundaries of the ELB should be assumed fixed;

(v) the existence of new investment contracts or other relevant contracts.

Future Load Growth

3.34 In performing the optimisation regard should be given to current maximum load capacity and projected future changes in demand and load characteristics. This should be done in accordance with time horizons used in efficient system planning – 10 years for transmission and subtransmission systems, zone substations and distribution systems. Allowances should be made, where possible, for different growth rates in different parts of the network.

3.35 However, future projected load growth is relevant only for determining whether or not there may be excess capacity in the existing system. In no circumstance should the optimisation process lead to system capacity greater (or more costly) than is currently in place.

Identifying Stranded Assets

3.36 Any system fixed assets that, because of past reductions in demand or any other reason, are no longer needed to supply line services should be identified – such assets have effectively become stranded.

Optimising the System Configuration

3.37 Optimisation of system configuration should be carried out in conjunction with the ELB's Planning Engineer with a view to considering what alternative configurations may be able to match the existing security of supply and other standards.

3.38 Relevant aspects of standards are:

(i) the degree of security (or redundancy) in different circumstances/localities – proportions of customers subject to interruptions, the number and duration of outages and types of customers affected (eg urban and rural, residential, commercial and industrial);

(ii) voltage stability;

(iii) levels of electrical losses.

3.39 The degree of security may be assessed by reference to the level of in-built redundancy, ie as (n) or (n-1) or (n-2) or greater component redundancy. (An (n) security level implies no component redundancy so that if a component fails, then customer supply is lost. An (n-1) security level is one in which customer supply is not interrupted in the event of any single component outage etc.)

3.40 In the case of Transpower account should be taken of prudent standards and practices followed in overseas countries, such as those adopted in Australia and the United Kingdom, views of the users of the transmission system on the overall system reliability where these views are expressed within the contractual relationship between Transpower and the connected party(ies) or as might be set as Transpower's performance requirements in supporting the operation of the electricity market.

3.41 In the process of optimising the system configuration, certain assets or groups of assets may become excess to requirements, while other new assets may also need to be notionally brought in. Issues with the optimisation of the system configuration for ELBs are discussed further in Appendix C.

Optimising Elements in the System

3.42 After the overall design of the system has been optimised the elements within it should be optimised by considering whether lower rating elements would be adequate to deliver the same security of supply and other standards.

3.43 In assessing what equipment is appropriate, relevant security of supply and other standards will include those of 3.38, but also safety standards may be of importance at the individual asset level. Issues with the optimisation of elements of ELB systems are discussed further in Appendix C.

Determining the Optimised Depreciated Replacement Cost (ODRC)

3.44 Once the optimised system has been determined those parts of the system which are different from the existing un-optimised system need to be re-evaluated. This entails applying adjusted replacement cost values and ensuring these are appropriately depreciated.

3.45 Any stranded assets should be valued at Net Saleable Value (NSV) (sale value less recovery costs), and their value assigned to that of ‘other businesses’. This is consistent with the Avoidable Cost Allocation Methodology (ACAM) rules. Since stranded assets are ‘avoidable’ by the ELB, NSVs associated with their disposal should not be assigned to the system fixed assets, nor to any other assets of the line business.

3.46 When assets become excess to requirements as a result of optimising the system configuration they should be valued at nil. This is because they are of no real value to the system. However, the optimisation is only notional so they cannot be disposed of to obtain an NSV. On the other hand any new assets that are notionally brought into the system through optimisation should be valued at their replacement cost, with reference to the costs in the Appendix B tables.

3.47 When as a result of optimising elements it becomes clear that certain assets are over-designed or have excess capacity, they should be notionally replaced by lower rating assets at their replacement cost, with reference to the costs specified in Appendix B. Thus the over-design or excess capacity is effectively valued at nil.

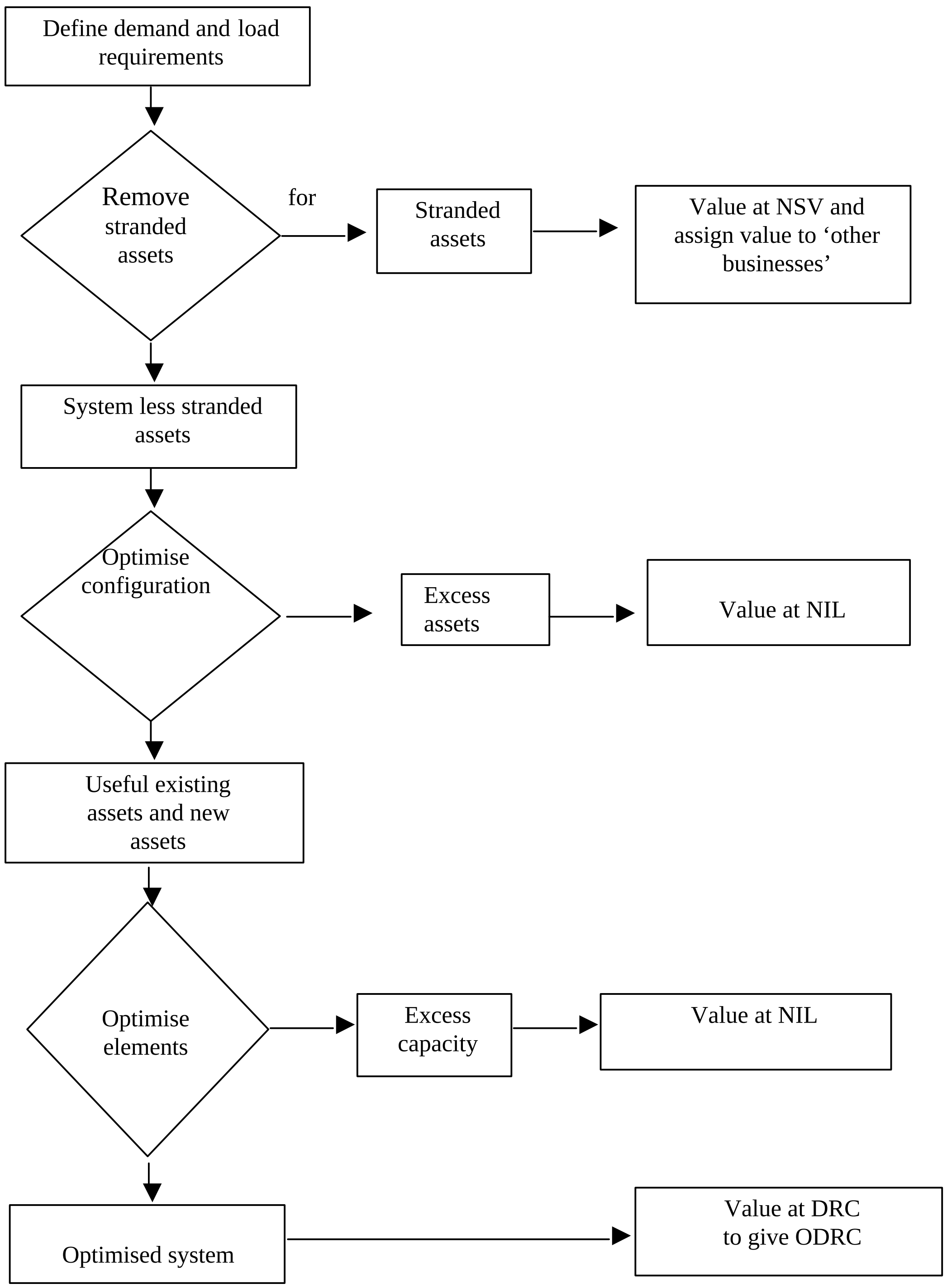
3.48 When the optimisation leads to individual assets being replaced, the replacement asset should be depreciated for the same proportion of its TL as the existing asset was depreciated. When the optimisation involves groups of assets being re-configured, the replacement assets should be depreciated as a group to reflect the RL of the existing group as a proportion of that group’s TL, this being calculated on a weighted average basis.

3.49 Aggregation of the DVs of the fixed assets in the optimised system will produce the network ODRC as required by regulation 20. In addition, for those parts of the network where optimisation has occurred it will be possible to record both the DRC and the ODRC, as also required by regulation 20.

Summary of the Optimisation Process

3.50 Figure 3.1 summarises the steps that should be taken in carrying out optimisation and shows how they fit together.

Figure 3.1: System Optimisation



Valuation of the System Fixed Assets at Optimised Deprival Value (ODV)

Introduction

3.51 Once ODRC has been determined it is necessary to establish which segments of the network cannot, because of constraints on sustainable tariffs, earn a normal commercial rate of return on their ODRC value. The assets for these segments should be valued at EV not ODRC.

3.52 The process for determining which segments should have EV values, what those values should be, and the final network ODV, has the following steps:

(i) partitioning the network into segments and the selection of segments for EV analysis;

(ii) determining the maximum long run sustainable tariffs for those segments subject to EV analysis;

(iii) determining whether EVs or ODRCs should be applied to those segments subject to EV analysis;

(iv) for those segments where EV applies, determining their EV values;

(v) aggregation of segment values (whether ODRC or EV) to produce the network ODV.

Partitioning the Network

3.53 Generally networks should be partitioned into relatively small segments for EV analysis. It is difficult to give specific rules for such partitioning but the separability of assets into groups with:

(i) limited inter-group dependency;

(ii) significantly different cost characteristics;

should be considered.

3.54 As will become apparent, determining to which segments to apply EVs can be complex and time consuming. Thus there is a necessity to avoid as far as possible testing all segments to see whether an EV valuation might be appropriate. Those segments which are least likely to be able to support an ODRC valuation should be tested first – that is those segments with high costs and/or consumers that could choose to disconnect at relatively low tariffs. In some instances a projected future fall in consumption (perhaps because of closure of a major consumer) may indicate that an ODRC valuation may not be supportable.

3.55 When the outcome of the calculation on the initially selected segments is known, this may indicate that further segments should be selected and tested for EV applicability.

Determining Maximum Long Run Sustainable Tariffs

3.56 The maximum tariffs for network segments should be determined as those such that with any higher tariff the consumers would disconnect. They should be assessed as being at a level equivalent to the unit cost of the next best alternative source of energy, taking into account all operating and capital costs of alternatives.

3.57 A range of alternative sources of energy should be considered including:

(i) disconnection from the network and electricity supply from a local generator;

(ii) substitution of all or part of the electricity supply with other fuels; and

for local ELBs:

(iii) direct supply from the transmission grid or from a neighbouring ELB.

3.58 When assessing the maximum line charge tariff care is needed to ensure that the comparison of using the network with the costs of alternatives is carried out correctly – it should be carried out on a delivered energy cost basis. Thus the network maximum unitised line charge, as set by an alternative, is the full unitised cost of the alternative less the unit energy charge when using the network.

Determining Whether to Use EV or ODRC

3.59 Once the maximum long run sustainable tariff (or tariffs) has been determined this enables the long run annual revenue earning power of the network segment to be assessed. This should then be put together with the long run annual costs for the network segment to determine the annual Net Operating Profit After Tax (NOPAT):

NOPAT = Operating Revenue – Operating Costs – Depreciation – Income Tax.

3.60 Historical accounting information on operating costs may need to be referred to in order to estimate future operating costs of the segment. Historical information on average network operating costs is likely to include elements of fixed operating costs that are unavoidable by the core network, even if the network segment under study were to close. Any such fixed costs, if material, should be deducted from average costs to estimate operating costs for the segment.

3.61 Depreciation for the network segment is obtainable from the workings to calculate ODRC for the segment. Income tax should be calculated at the corporate tax rate of 33%.

3.62 How to value the segment depends on whether the segment is sustainable in its own right, that is whether NOPAT is enough to give a normal rate of return on the segment assets valued at ODRC. The decision rule is

NOPAT < WACC x ODRC	:	use EV
NOPAT > WACC x ODRC	:	use ODRC

where WACC = Weighted Average Cost of Capital for the business.

3.63 Appendix D gives details on the meaning of WACC and outlines how it may be determined for an ELB.

Determining EVs

3.64 If a network segment is not in its own right economically sustainable, then the ELB will have a commercial incentive to close it. Such closure should not necessarily be made immediately because there may be a period during which the lines could be profitable with earnings higher than short run costs (because short run maintenance and capital costs are less than such costs for long run sustainability).

3.65 However, the Electricity Act 1992 requires that all line connections be maintained until 31 March 2013 unless consumers agree to disconnection. Thus the ability to gain consumer approval to disconnect, and when this might be effected, is of crucial importance for the determination of EVs and potentially for ELB profitability.

Lines Not Subject to Closure in 5 to 6 Years

3.66 Unless an ELB has plans for closing a segment within the next 5 to 6 years (for which it believes it can gain consumer approval), then for the purposes of determining an EV valuation, it should be adequate to assume that the lines in question will remain in operation in perpetuity (apart from the uncertainty of closure more than 5 to 6 years ahead, discounting far ahead cash flows limits their impact on the resulting EV estimate).

3.67 It is acceptable for EV valuation purposes to allow for tariffs below the maximum sustainable level, although an ELB may wish to have them tracking up to this level over a period of years.

3.68 In cases when it is assumed that a segment will remain in operation in perpetuity the EV should be determined as:

EV = PV(NOPAT annually in perpetuity)

where the revenue component of NOPAT may be subject to tariffs below the maximum long run sustainable level, and the relevant discount rate is the WACC.

3.69 Given the difficulties of determining EVs with any precision, the above approach is considered acceptable. However, a more detailed cash flow analysis, such as presented in the following section (for lines with planned lives of less than 5 to 6 years), is not precluded for lines planned to remain in operation for more than 5 to 6 years.

Lines to Close in 5 to 6 Years

3.70 For lines when agreement can be reached with consumers, and arrangements made for disconnection within 5 to 6 years, a detailed cash flow analysis is needed to determine when to disconnect and to determine the associated EV value. (If a major consumer is projected to close then presumably agreement of the consumer would not be needed to disconnect.) What is required is to maximise the Present Value (PV) of the net earnings to closure of the network segment plus the PV of the Net Residual Value (NRV) at closure. If immediate closure is possible then the EV = NRV. More generally:

EV = Max PV (FCF to closure + NRV at closure)

where FCF = Free Cash Flows (dealt with in more detail below) and the discount rate to determine the PV is the WACC.

3.71 The aim is to determine the actual cash flows for the network segment for the period up to and including closure, and to avoid having the valuation distorted by notional allowances for capital expenditure through depreciation. The estimated cash flows should be prepared on an after tax basis so that the PV can be determined using the nominal post-tax WACC used throughout this handbook. Accordingly the FCF are given by:

FCF = Operating Revenue – Operating Costs – Capital Costs (if any) – Income Tax.

3.72 An economic planning exercise will be required for the network segment to estimate the forward FCF. If such an exercise is to be based on historical accounting information, care is needed in converting normal accounting items in to FCF. In particular it should be noted that only system fixed costs that can be avoided as the result of closing the network segment should be attributed to the segment in an FCF analysis. Other adjustments, such as are normally made in converting income statement and balance sheet information into a cash flow analysis, are also required.

3.73 If assets left at the closure of a network segment are of no value then:

NRV = recovery costs (ie the NRV is negative).

3.74 If assets left at the closure of a segment are potentially useful as spares for the network then:

NRV = DRC – recovery costs.

This is providing that the movement of the assets into store would not lead to the total level of such spares exceeding a reasonable level for the network.

3.75 If assets left at the closure of a segment are potentially of value, but excess to the requirements of the network, then the

NRV = NSV (ie Net Saleable Value less recovery costs).

3.76 It should be noted that the NSVs of assets considered excess in EV analysis may be included in the EV valuation. This is in contrast to the procedure for NSVs of stranded assets. The circumstances in each case are different.

3.77 Since stranded assets are 'avoidable' by the line business their NSVs should be attributed to 'other businesses' and not the line business. Stranded assets may in some cases have high NSV values.

3.78 In general, assets made excess in EV analysis are likely to be required for a year or two to provide line services before becoming redundant – such assets are not 'avoidable' – they form a worthwhile part of the system fixed assets, albeit for a limit period. Also it should be noted that such assets are likely to be nearing the ends of their lives and have relatively low NSVs.

3.79 The issue of how to treat NSVs of assets made excess in EV analysis may not be entirely clear-cut but, taking the above considerations into account, it has been decided that it is acceptable for these NSVs to be incorporated in EV valuations.

Negative EVs

3.80 In some extreme cases, the maximum revenue (including any relevant NRV) from a network segment may be insufficient to cover costs (indeed revenue may be insufficient to cover operating costs alone) and the resulting EV will be negative. The negative EV should be applied. Clearly in cases such as this the ELB will have a strong incentive to reach agreement with consumers on closure as early as possible. The ELB may wish to give consideration to assisting consumers switching to an alternative source of energy. If costs are associated with such support it is acceptable to include these costs in the determination of the EV.

Determining the Network ODV

3.81 Aggregation of the values (whether ODRC or EV) of the network segments post-optimisation and post-economic value analysis will produce the network system fixed assets ODV as required by regulation 20. In addition, for those parts of the network where EV values have been applied it will be possible to record both the ODRC and the EV, as also required by regulation 20.

APPENDIX A: ASSET TYPES, GROUPS AND SUBGROUPS FOR . ELECTRICITY LINE BUSINESSES

Asset registers should include, as a minimum, the classification of assets such as set out in this appendix.

A. TRANSPOWER

(a) AC Transmission Lines

Transmission lines should be divided into subgroups by voltage: 11kV, 33kV, 50kV, 66kV, 110kV and 220kV.

Further subdivision should be by conductor size.

For standard valuation purposes the unit is 1km.

(b) Benmore-Haywards HVDC Link

The Benmore-Haywards HVDC link including land and buildings should be recorded.

(c) AC Substation Equipment

Substations should be divided into subgroups as follows:

Category	**Average No. of Incoming HV bays**
MAJOR	**14**
Medium	8
Small	6
Rural	2

B. TRANSPOWER and LOCAL ELBs

(d) Subtransmission

Subtransmission Lines

Subtransmission lines should be divided into subgroups by voltage: 22kV, 33kV, 66kV and 110kV.

Further subdivision should be by conductor size (eg 185mm^2 aluminium, 100mm^2 aluminium).

For standard valuation purposes the unit is 1km.

Subtransmission Cables

Subtransmission cables should be divided into subgroups by voltage: 33kV and 110kV. If cable sizes differ markedly within an ELB, the quantities should be recorded separately for ranges of capacity.

For standard valuation purposes the unit is 1 km.

(e) Zone Substations

Zone substations should be divided into subgroups by capacity: 0-5MVA, 6-10MVA, 11-20 MVA, 21-30MVA, over 30MVA.

Numbers of substations should be determined separately for the asset categories identified in Table B.1 of Appendix B.

Equipment owned at associated points of supply should be listed under this section eg circuit breakers, metering and communications equipment.

Ripple injection equipment should be included under this class of asset and will incorporate control equipment, tuned circuit, coupling equipment and remote units. The master station should be included separately with the system control facilities.

For standard valuation purposes the unit is one substation.

(f) Distribution

Medium Voltage Lines

MV distribution lines should be divided into subgroups by voltage, conductor size ranges and type:

(i) 6.6kV, 11kV and 22kV
(ii) (150mm^2 to 300mm^2 Al incl) etc aluminum or equivalent
(iii) 3 phase, single phase, SWER
(iv) lines with more than one voltage.

For standard valuation purposes the unit is 1 km.

Medium Voltage Cables

MV distribution cables should be divided into subtypes by voltage: 6.6kV, 11kV and 22kV.

If necessary, they should also be divided by conductor size.

For standard valuation purposes the unit is 1km.

(g) Medium Voltage Switchgear

MV switchgear should be divided into subgroups by type. Voltage regulators are to be included in this group.

(h) Distribution Substations

Distribution substations should be divided into subgroups: pole mounted, ground mounted (covered), indoor (kiosk) or on customers' premises.

Consumer substations with the substation sited in a customer's premises should be treated as a subgroup.

For standard valuation purposes the unit is one substation.

(i) Distribution Transformers

Distribution transformers should be divided into subgroups by size.

For standard valuation purposes the unit is one transformer.

(j) Reticulation

Low Voltage Lines

It should not be necessary to divide low voltage lines into subgroups by conductor size or according to whether there are one, two or three phases. However, the lines should be divided into subgroups by type: overhead and underbuilt. Streetlighting mains, should be recorded separately.

For standard valuation purposes the unit is 1km.

Low Voltage Cables

It should not be necessary to divide low voltage cables into subgroups by conductor size, Streetlighting mains, should be recorded separately.

For standard valuation purposes the unit is 1km.

(k) Customer Service Connections Excluding Meters and Relays

This class of asset includes cable or line connections from the mains to the property boundaries and includes LV fuses. The assets should be divided into subgroups according to whether they are for one or three phases.

For standard valuation purposes the unit is 1 service.

(l) System Control Facilities

Most local ELBs have only one system control centre which, along with any other system control facilities, should be recorded separately as a master station. Remote units should be recorded with the appropriate zone substation.

(m) Communication Facilities

This class of asset comprises:

(i) terminal facilities: these should be recorded as a group with the master station and the remote units recorded with the zone substation.

For standard valuation purposes the unit is one terminal.

(ii) lines/cables: these should be subgrouped if necessary.

For standard valuation purposes the unit is 1km.

(n) Miscellaneous Equipment

This class of asset includes items such as air break switches and auto reclosers.

(o) Stores and Spares

The stock of stores and spares should be recorded.

(p) Land

Land owned by ELBs on which substations are built should be recorded.

(q) Easements

Easements which qualify for assessment (see B.29) should be recorded.

APPENDIX B: VALUING ASSETS AND MAXIMUM ASSET COSTS AND LIVES

B.1 This appendix gives the methodology that should be applied in using replacement costs to value the system fixed assets of ELBs. The appendix also contains Table B.1 (for local ELBs), and Tables B.2–B.8 (for Transpower), which specify the maximum replacement costs and the maximum asset lives to be used for the purpose of assessing the depreciated replacement costs of ELB system fixed assets.

ELB MAXIMUM COSTS

B.2 Maximum replacement costs are shown in Table B.1 (for local ELBs), and Tables B.2–B.8 (for Transpower). These values are maxima and for valuation purposes are not to be exceeded.

B.3 The values in the tables are based on installed costs for Modern Equivalent Assets (MEA). They have been based on industry best practice and competitive pricing and include the following elements:

(i) costs of materials delivered to store

(ii) direct labour including indirect costs (ACC, holiday pay, sick leave, training, supervision, etc)

(iii) transport and plant costs for delivery and erection

(iv) on-cost incorporating business administration, design, construction supervision, and project management costs.

The costs of land use consents, easements, compensation are excluded. GST is excluded but other taxes and duties incurred in the construction of the assets are included.

B.4 For equipment used in adverse conditions multipliers can be applied to the values as specified in the tables, but only subject to conditions as specified in B.9, B.14 and B.15. To ensure appropriate application of the cost multipliers, a record of their application should be kept for scrutiny and approval by the Valuer. This information must include:

(i) multiplier used

(ii) quantity of item to which it is applied

(iii) the specific conditions justifying the use of the multiplier.

B.5 Where the nature of an asset in service differs from any in the tables, an engineering assessment of the replacement cost can be made, subject to the approval of the Valuer. Before such an assessment is made, the Valuer must be satisfied that there is justification for not selecting an MEA listed in the tables. This assessment must be recorded in the valuation report.

B.6 In assessing costs for assets not listed in the tables, or where the Valuer's assessed value is less than the maximum listed cost, the cost elements set out in B.3 should be recorded. Any costs so determined should be based on competitive pricing estimates, and should be commensurate with a significant scale of construction (within the limits of available resources), not piecemeal additions.

ELB Asset Types

B.7 In the following sections additional information is given in relation to the valuation of certain types of asset used by ELBs.

Overhead lines

B.8 **Local ELBs:** The maximum overhead 33kV and 11kV line costs in Table B.1 have been based on three phase construction in a rural environment utilising 70-80m spans. For lines of these voltages in other environments, maximum costs can be established by applying the following multipliers:

overhead line urban	:	1.5 to 1.8 times B.1 cost
overhead line remote area	:	1.0 to 1.25 times B.1 cost
overhead line rugged terrain	:	1.2 to 1.3 times B.1 cost;

where remote areas are those which are situated more than 75 km from the nearest works depot of either the ELB or a line construction contractor; rugged terrain includes those areas where normal line operating vehicles and plant cannot be used and where it is necessary to use helicopters, tracked vehicles or other special plant.

B.9 **Transpower:** The maximum overhead line costs for AC transmission lines in Table B.8 have been based on nominal average span lengths of 165m and 375m for pole and tower lines respectively, in flat rural land with an assumption that the work is carried out 50km from the nearest urban area. There is no adjustment for further remoteness. Costs for overhead lines in Table B.8 in other terrain can be established by applying the following multipliers:

overhead line hilly terrain	:	1.07 times B.8 cost
overhead line mountainous terrain	:	1.23 times B.8 cost
overhead line urban terrain	:	1.20 times B.8 cost

B.10 The maximum costs in Table B.1 for circuits of lower voltage erected on higher voltage lines (ie underbuilt) have been based on the marginal cost of additional materials and installation.

B.11 Costs for special configurations (eg composite 33kV/11kV/LV lines and aerial bundled conductor construction) and for construction at other voltages (eg 110kV, 66kV or 22kV) should be determined by the Valuer in accordance with clause B.6.

Underground Cables

B.12 Underground cables should be valued on the basis of replacement cost with underground cables in determining RC or DRC, but this should be reviewed as part of the optimisation process (see Appendix C).

B.13 The maximum underground cable costs in Table B.1 have been based on laying in an urban area with developed infrastructure.

B.14 Cables laid in central city areas (central business districts) require special consideration, and a multiplier of 1.15 or 1.25 times the costs of Table B.1 can be applied. This multiplier takes into account the greater vehicular and pedestrian traffic, restricted access times, special reticulation requirements and areas requiring substantial reinstatement.

B.15 For cables laid in rocky ground a multiplier of 1.5 to 2.0 times the costs of Table B.1 can be applied.

B.16 The Table B.1 cost of double circuit (viz two) cables including cables of differing voltages laid together incorporates the marginal cost of the extra cable and laying in a joint trench. Where more than two cables of the same voltage are laid together the replacement cost should be determined in accordance with this principle and clause B.6.

B.17 The cost of cables intended to operate at voltages other than 33kV, 11kV, LV and submarine cables should be determined by the Valuer in accordance with clause B.6.

B.18 The standard replacement cost of all 33kV and MV cables should be based on unarmoured XLPE cables being the deemed MEA. The replacement cost of LV cables should be based on PVC or XLPE unarmoured construction.

Zone Substations

B.19 The replacement costs for zone substations should be based on cost effective configuration with single bus distribution switchgear unless there are compelling reasons for departure from this. The replacement costs should be compiled by the Valuer in accordance with clause B.6 and should be presented in the categories set out in Table B.1 (for local ELBs) and Tables B.2 and B.3 (for Transpower).

B.20 The replacement cost of substation buildings should be included in the substation valuation, but the land value should be treated separately.

Distribution Substations

B.21 Distribution substations should be valued without distribution transformers, and the land value should also be treated separately. The replacement cost of any enclosing structure should, however, be included.

B.22 The replacement cost of pole mounted substations should include the cost of steelwork, extra poles if applicable, LV fuses and earthing. In the case of ground mounted or similar transformer/substation units the relevant cost is the cost of the additional equipment which is added to the transformer excluding MV switchgear.

Distribution Transformers

B.23 Replacement costs for distribution transformers are given in Table B.1 (for local ELBs) for currently available distribution transformer sizes of New Zealand manufacture. Replacement costs for distribution transformers for Transpower are given in Table B.4. Where other sizes are in service, the cost of the next largest available size should be used for valuation purposes.

Streetlighting Mains

B.24 For valuation purposes the MEA of streetlighting mains can be a photo-electric cell included as an integral part of the lantern where the streetlights are in close proximity to existing LV reticulation. Where LV reticulation is not available, streetlighting mains can be valued as a stand alone 2 core cable.

System Control Facilities

B.25 All system control facilities associated with a system control centre should be valued together as a master station. The value of remote units should be incorporated in the value of the appropriate zone substation.

Communication Facilities

B.26 Terminal facilities should be valued as a master station. The value of remote units should be incorporated in the value of the appropriate zone substation.

Stores and Spares

B.27 Only a reasonable quantity of stores and spares should be valued as part of the system fixed assets (consistent with the Avoidable Cost Allocation Methodology (ACAM) rules). Any excess stores and supplies (including spares for assets no longer in service) should be valued at Net Realisable Value (NRV) and the valuation not included with that of the line business, but with that of ‘other businesses’ owned by the ELB.

Easements

B.28 The "existing works" provisions in the Electricity Act 1992 protect the ownership of lines (both local ELBs and Transpower) constructed or commenced prior to Januray 1993. They also provide for line owner access to the land the works are on, to inspect, maintain and operate them. Under the previous legislation the Crown and Electricity Supply Authorities had virtually unlimited rights of access to land to build works. Easements were not required. Easements are not explicitly required by the Electricity Act 1992, but are expected to be the normal means of registering rights. Easements are not explicitly required by the Electricity Act 1992, but are expected to be the normal means of registering rights.

B.29 Only easement rights obtained and registered against a land title after after 1 January 1993, (or in the case of Transpower, additionally between 1 January 1988 and 1 January 1993), and paid for, can be valued provided that the sum paid has not already been expensed.

ELB Maximum Lives

B.30 Maximum asset lives are given in Table B.1 (for local ELBs) and Tables B.2-B.8 (for Transpower). These lives are maxima and are not to be exceeded for the purpose of determining TLs of assets, except as provided for in B.34.

B.31 Where an asset is made up of a number of items that have differing lives, a weighted average life is to be determined. This assessment should be recorded in the valuation report.

B.32 Lives of assets not listed in Table B.1 (for local ELBs) and Tables B.2-B.8 (for Transpower) should be established on a comparable basis with those in the tables. Such lives should not exceed the maximum lives for comparable assets, should be subject to the approval of the Valuer, and should be verified and documented. Assessment of the TL of such assets must include:

(i) examination of asset service records;

(ii) discussion with maintenance personnel; and

(iii) physical inspection.

B.33 TLs less than the maxima of Table B.1 (for local ELBs) and Tables B.2-B8 (for Transpower) should be assigned when the Valuer considers this appropriate. Circumstances when this could be appropriate include:

(i) assets in coastal environments;

(ii) assets subject to particularly high use or high fault levels or showing systematic premature retirement due to failure;

(iii) assets which have been poorly maintained.

TLs so assigned should, however, never be less than 50 percent of the relevant Table B.1 maximum.

B.34 The TL of certain assets, as specified below, may be extended by the Valuer where specified conditions have been satisfactorily met. These are:

zone substation transformers	(clause B.43)
indoor MV or indoor 33kV switchgear	(clause B.44)
distribution transformers	(clause B.45)
transmission lines	(clause B.46)

B.35 In order to justify the extension of TLs as provided in B.34, the following information should be available to the Valuer for scrutiny:

(i) an age profile of the assets in the category concerned, showing the original population, survival population in each year and number of failures in each year, sufficient to demonstrate that the asset category concerned warrants on average the application of life extension; and/or

(ii) information on the standard or specification used in the purchase of the asset or that class of asset sufficient to demonstrate modern or special technology that would warrant the application of a longer life.

B.36 In addition the following information should be available:

(i) a maintenance policy statement indicating the nature, scope and regularity of maintenance work carried out on the asset or class of asset since its installation, sufficient to support the claim for a longer life;

(ii) maintenance and test records of the asset (or, where the life extension relates to a class of asset, representative records for that class of asset) sufficient to demonstrate that the agreed maintenance policies have been applied over the life of the asset; and

(iii) where relevant (eg for transformers), information on the loading applied to the asset or class of asset over time, demonstrating circumstances that would warrant a life extension.

Assessing Remaining Lives

B.37 The life of each asset commences when the equipment is commissioned.

B.38 Refurbishment is classed as work done on the asset (or set of assets) that results in a material extension of its service life beyond its normal TL. This is in distinction to maintenance work which is done to ensure that an asset is able to perform its designated function for its normal TL. Accumulated maintenance should not be considered as refurbishment.

B.39 When an asset has been refurbished, the Valuer should assign an RL, effective from the time of refurbishment, but this RL should not be greater than the maximum TL as specified in Table B.1 (for local ELBs) and Tables B.2-B8 (for Transpower).

B.40 When an asset has not been refurbished but is still in service at the end of its TL, the Valuer may allow for a minimum RL, of at least one year but not more than three years, for that asset.

Lives for Particular Asset Types

B.41 In the following sections additional information is given in relation to the assessment of lives of certain types of asset.

Overhead Lines

B.42 Two different sets of life maxima are given in Table B.1 – one for concrete poles, the other for wooden poles. This is notwithstanding the fact that a single set of maximum values has been given reflecting the MEA asset replacement type.

Zone Substations

B.43 The maximum TL of zone substation transformers is to be taken as 45 years, as shown in Table B.1. However, in accordance with clause B.35, where sound maintenance programmes have been in place over the life of the asset, the TL for such transformers may be extended, but to not more than 60 years. Such an extension assumes a typical urban and commercial load curve and cyclic loading in accordance with IEC 354 and should cover most situations in New Zealand. For such extensions, the Valuer should be provided with all required supporting information.

Indoor switchgear

B.44 The maximum TL of indoor MV switchgear is to be taken as 45 years, as shown in Table B.1. However, in accordance with clause B.35, where indoor MV switchgear is of modern, sealed design and specified to operate without maintenance for an extended number of operations, the TL may be extended, to not more than 55 years. In such cases, the Valuer should be advised of the type of switchgear installed and the Standard (IEC) to which it has been constructed. The TLs in this clause are also applicable to indoor zone substation incoming (33kV) switchgear. (Normally, however, such switchgear is outdoor.)

Distribution Transformers

B.45 The maximum TL of distribution transformers is to be taken as 45 years, as shown in Table B.1. However, in accordance with clause B.35, distribution transformer lives may be extended, but to not more than 55 years, providing that general maintenance, including tank replacement during the life of the transformer, is expensed and not capitalised. The major factor in determining the ultimate life of the transformers is then the life of the core and windings. For the application of an extension to the TL, the Valuer must be provided with all required supporting information.

Transmission Lines

B.46 The maximum TL of transmission lines is to be taken as 55 years, as shown in Table B.8. This is the TL allowed for transmission lines constructed in areas with normal environmental conditions. Transmission lines in coastal (hostile corrosive environment) is to be accorded an asset TL of only 35 years, and, in accordance with clause B.34, transmission lines lives may be extended, but to not more than 70 years, where those transmission lines are in lower than normal corrosive conditions (dry inland).

Valuation of the DC Link

B.47 The HVDC link between Benmore and Haywards is a major component of the transmission system. The HVDC link is an asset whose economic value is based on the service it provides to the New Zealand electricity system. Because of the size of the investment in DC assets it is essential that the economic valuation of this asset is carried out carefully and objectively.

B.48 The High Voltage Direct Current link should be valued using the standard ODV methodology. The factors that should be addressed in the valuation include:

- The economic justification for the link;
- The risk of physical or functional failure of the link; and
- The risk of under-utilisation of the link, either for operational reasons, or due to insufficient generation in the South Island or due to major new load arising in the South Island or additional generation built in the North Island.
- The EV of the link should be assessed in terms of its value to the system. This involves an assessment of what the system costs (ie both generation and transmission) would have been in the absence of any link, or with a link of different size or specification level.

Local ELB Maximum Costs and Lives

B.49 The following table gives maximum replacement costs and lives that should be applied in valuing local ELB system fixed assets.

TABLE B.1: LOCAL ELB MAXIMUM ASSET VALUES AND LIVES (1998 TABLE REVISION)

Asset Description	Unit	Notes	Maximum Value ($000) a	Maximum Life (Years)	
				Pole Type	
SUBTRANSMISSION				Concrete	Wood
33 kV Lines – Heavy (≥ 150 mm^2, ≤ 300 mm^2 Al)	km	b	40	60	45
33 kV Lines – Light (< 150 mm^2 Al)	km	b	35	60	45
33 kV Lines – DCct Heavy	km	b	60	60	45
33 kV Lines – DCct Light	km	b	50	60	45
				Cable Type	
				XLPE	PILC
33 kV - Cables (≤ 240 mm^2 Al)	km	c	165	45	70
33 kV - Cables DCct (≤ 240 mm^2 Al)	km	c	265	45	70

Pilot/Communications Ccts O/H	km	b	**	45	
Pilot/Communications Ccts U/G	km	c	**	45	
Air Break Switch	No.	b	8	35	
ZONE SUBSTATIONS					
Land	No.		-	-	
Site Development and Buildings	No.		**	40	
Incoming (Outdoor) Switchgear, Protn. & Controls	No.	d	**	40	
Transformers	No.	e	**	45	
Transformer Protection and Controls	No.		**	40	
MV CB, Protection and Controls (Incom/Bus)	No.	d	**	45	
MV CB, Protection and Controls (Feeder)	No.	d	**	45	
				Pole Type	
				Concrete	Wood
Outdoor Structure if not included above	No.		**	60	45
SCADA and Communications Equipment	No.		**	15	
Ripple Injection Plant	No.		**	20	
Other Items	No.		**	40	
				Pole Type	
DISTRIBUTION				Concrete	Wood
MV Lines					
11 kV O/H Heavy (≥ 150 mm^2, ≤ 240 mm^2 Al)	km	b	24	60	45
11 kV O/H Medium (> 50 mm^2, < 150 mm^2 Al)	km	b	22	60	45
11 kV O/H Light (≤ 50 mm^2 Al)	km	b	20	60	45
11 kV O/H DCct Heavy	km	b	34	60	45
11 kV O/H DCct Medium	km	b	31	60	45
11 kV O/H DCct Light	km	b	28	60	45
11 kV O/H Underbuilt Heavy	km	b	10	60	45
11 kV O/H Underbuilt Medium	km	b	9	60	45
11 kV O/H Underbuilt Light	km	b	8	60	45

Asset Description	**Unit**	**Notes**	**Maximum Value ($000)** a	**Maximum Life (Years)**	
DISTRIBUTION (Continued)				Cable Type	
MV Cables				XLPE	PILC
11 kV U/G Heavy (> 240 mm^2, ≤ 300 mm^2 Al)	km	c	120	45	70
11 kV U/G Medium(> 50 mm^2, ≤ 240 mm^2 Al)	km	c	90	45	70
11 kV U/G Light (≤ 50 mm^2 Al)	km	c	65	45	70
11 kV U/G DCct Heavy	km	c	170	45	70
11 kV U/G DCct Medium	km	c	135	45	70
MV SWITCHGEAR					
Disconnector (Excl Pole)	No.		2.3	35	
Load Break Switch (Excl Pole)	No.		5.5	35	
Dropout Fuse 3 Ph (Excl Pole)	No.		1.5	35	
Oil Sw/Sectionaliser (Excl Pole)	No.		17	40	

Recloser (Excl Pole)	No.		20	40
Circuit Breaker	No.		25	40
Voltage Regulator	No.		**	55
Ring Main Unit - 3 Way	No.		15	40
Extra Oil Switch	No.		5	40
Extra Fuse Switch	No.		8	40
DISTRIBUTION TRANSFORMER (kVA)				
Single/Two Phase Units				
10	No.	f, g	2.4	45
15	No.	f, g	2.5	45
30	No.	f, g	3.1	45
50	No.	f, g	4.2	45
Three Phase Units (Pole Mounted - Bushing Terminations)				
15	No.	f, g	3.3	45
30	No.	f, g	3.6	45
50	No.	f, g	4.7	45
100	No.	f, g	7	45
200	No.	f, g	11	45
300	No.	f, g	12.9	45
500	No.	f, g	18	45
Three Phase Units (Cable entry, one or both voltages)				
100	No.	f, g	7.5	45
200	No.	f, g	11.5	45
300	No.	f, g	13.3	45
500	No.	f, g	18.5	45
750	No.	f, g	22	45
1,000	No.	f, g	24.9	45
1,250	No.	f, g	33	45
1,500	No.	f, g	39	45
DISTRIBUTION SUBSTATIONS				
Pole Mounted (50 kVA or less)	No.	h	0.5	40
Pole Monted (100 kVA or more)	No.	h	1.8	40
Ground Mounted (Covered)	No.	i	4	40
Kiosk (Masonry or block enclosure)	No.	i	9	40
On Customer’s Premises with Feedout	No.		2	40

Asset Description	Unit	Notes	Maximum Value ($000) a	Maximum Life (Years)	
				Pole Type	
LV LINES				Concrete	Wood
Overhead - LV only	km	j	38	60	45
Overhead Underbuilt	km	j	12	60	45
				Cable Type	
				XLPE /PVC	PILC
Underground - LV Only	km	j, k	55	45	70
Underground - with MV	km	j, k	25	45	70
CUSTOMER SERVICE CONNECTIONS EXCLUDING METERS AND RELAYS					
LV - 1 ph	No.		0.07	45	
LV - 3 ph	No.		0.18	45	
OTHER SYSTEM FIXED ASSETS					
SCADA and Comms (Central Facilities)	Lot		**	15	

a All values are based on installed costs (excluding GST) for MEA.
b Values relate to costs for rural construction.
c Values are based on costs of underground reticulation for suburban areas in average ground conditions.
d In accordance with clause B.43 (and the requirements of clause B.33), the lives for indoor MV (or indoor 33kV) switchgear may be extended, to no more than 55 years, if it is of modern, sealed design and specified to operate without maintenance for an extended number of operations.
e In accordance with clause B.42 (and the requirements of clause B.33), of the lives of zone substation transformers may be extended, to no more than 60 years, provided that evidence of a sound maintenance programme is presented to the Valuer.
f Values based on replacement costs are for currently available sizes (NZ manufacture). For intermediate sizes value at next size up. (Optimisation factor should take account of any resulting enhancement.)
g In accordance with clause B.44 (and the requirements of clause B.33), the lives of distribution transformers may be extended, to no more than 55 years, provided that evidence of a sound historical maintenance programme over the life of the asset is presented to the Valuer.
h Excludes dropout fuses.
i Includes enclosure and LV frame. Use kiosk only where additional LV frames required.
j If detailed records of LV quantities are not available, the quantities used in the valuation should be based on an average length of LV for each size of transformer.
k Values are based on costs for suburban subdivisions.
** No maximum value assigned.

Transpower Maximum Costs And Lives

B.50 The following tables give maximum replacement costs and lives that should be applied in valuing Transpower's system fixed assets.

B.51 The maximum replacement costs included in the tables are subject to adjustment for seismic factors (for substations) and interest incurred during construction. The adjustment factors are shown tables B.9 and B.10.

SUBSTATIONS BY STANDARD SIZE

For valuing establishment and buildings, substations are split into facilities of four standard sizes - Major, Medium, Small and Rural.

Table B.2: Establishment Building Block Costs

Type	Description	Maximum Value ($000)	Maximum Life (years)
Major	accommodating on average 14x220kV, 19x110kV and 15x33kV or 15x11kV bays, roadways, etc	3,184.75	55
Medium	accommodating on average 8x220kV, or 8x110kV and 10x33kV or 10x11kV bays, roadways, etc.	1,203.07	55
Small	accommodating on average 6x110kV and 15x33kV or 15x11kV bays, roadways, etc	1,072.82	55
Rural	accommodating on average 2x66kV, 6x33kV or 6x11 bays, roadways, etc	973.34	55

Substations (Standard sizes) by Indoor/Outdoor

For costing buildings at substations, the four standard sizes are further broken down to differentiate between indoor or outdoor facilities.

Table B. 3: Buildings Building Block Costs

Type	Description summary	Maximum Value ($000)	Maximum Life (years)
Major OD	Facilities associated with outdoor switchyard with on average 14x220kV, 19x110kV and 15x33kV or 15x11kV bays, 155.5msq control room.	175.91	55
Major ID	Facilities associated with outdoor switchyardr with on average 14x220kV, 19x110kV bays and indoor switchgear and control facilities with on	365.81	55

Type	Description summary	Maximum Value ($000)	Maximum Life (years)
	average 15x33kV or 15x11kV bays with 155.5sqm control room and 201.6sqm switchgear room		
Medium OD	Facilities associated with outdoor switchyard with on average 8x220kV or 8x110kV and 10x33kV or 10x11kV bays, 103.7msq control room	143.30	55
Medium ID	Facilities associated with outdoor switchyard with on average 8x220kV or 8x110kV bays and indoor switchgear and control facilities with on average 10x33kV or 10x11kV bays with 103.7sqm control room and 159.6sqm switchgear room	143.30	55
Small OD	Facilities associated with outdoor switchyard with on average 6x110kV and 10x33kV or 10x11kV bays, 86.4msq control room	121.65	55
Small ID	Facilities associated with outdoor switchyard with on average 6x110kV bays and indoor switchgear and control facilities with on average 10x33kV or 10x11kV bays with 86.4sqm control room and 159.6sqm switchgear room	286.87	55
Rural OD	Facilities associated with a rural outdoor switchyard with on average 2x66kV and 6x33kV or 6x11kV bays, 69.1sqm control room	112.95	55
Rural ID	Facilities associated with outdoor switchyard with on average 2x66kV bays and indoor switchgear and control facilities with on average 6x33kV or 6x11kV bays with 69.1sqm control room and 109.2sqm switchgear room	244.86	55

Transformers

Replacement costs for a large number of power transformer options have been provided to cover the range of power transformer sizes and configurations used by Transpower. Generally, costs are provided for power transformers with On-load Tap Changers, except where identified.

Table B. 4: Power Transformer Building Block Costs

HV	LV	TV/ MVA	Vector	Phase	MVA 3ph	OLTC	Maximum Value ($000)	Maximum Life (years)
220	110	11/60	A	3	200	No	2,842.58	55
220	110		A	3	200	Yes	2,535.81	55
220	110	11/60	A	1	200	Yes	1,541.83	55
220	110		A	3	180	Yes	2,372.31	55
220	110	14.5/ 141.5	A	3	141.5	Yes	2,300.44	55
220	110		A	3	120	Yes	2,062.22	55

HV	LV	TV/ MVA	Vector	Phase	MVA 3ph	OLTC	Maximum Value ($000)	Maximum Life (years)
220	110	11/60	A	3	100	Yes	1,958.86	55
220	110		A	3	100	Yes	1,852.42	55
220	110	11/60	A	1	100	No	1,056.57	55
220	110		A	3	90	Yes	1,907.18	55
220	110	33/30	A	3	70	Yes	1,803.81	55
220	110	11/30	A	1	65	No	902.01	55
220	110	11/30	A	3	60	Yes	1,752.13	55
220	110	11/30	A	3	50	No	1,489.46	55
220	110	11/30	A	1	50	No	836.11	55
220	66	11/60	S-S	3	200	Yes	3,047.37	55
220	66	11/60	S-S	1	200	Yes	1,643.80	55
220	66	11/60	S-S	3	100	No	2,151.45	55
220	66	11/60	S-S	1	100	No	1,126.35	55
220	66	33/30	S-S	3	70	Yes	1,930.09	55
220	66	11/30	S-S	1	50	No	917.92	55
220	55		TR	1	18	Yes	820.79	55
220	55		TR	1	15	Yes	778.87	55
220	33		S-D	3	200	Yes	3,278.42	55
220	33		S-D	1	200	Yes	1,315.29	55
220	33		S-D	3	150	Yes	2,715.32	55
220	33		S-D	3	120	Yes	2,366.39	55
220	33		S-D	3	100	Yes	2,273.37	55
220	33		S-D	1	100	Yes	1,000.29	55
220	33		S-D	1	63	No	793.15	55
220	33		S-D	3	60	Yes	1,668.55	55
220	33		S-D	3	50	Yes	1,639.87	55
220	33		S-D	1	50	No	723.70	55
220	33		S-D	1	30	No	616.84	55
220	33		S-D	3	30	Yes	1,319.64	55
220	33		S-D	3	25	Yes	1,261.48	55
220	33		S-D	3	20	No	1,155.49	55
220	33		S-D	3	18	Yes	1,180.06	55
220	33		S-D	3	15	Yes	1,145.17	55
220	33		S-D	3	10	Yes	1,017.85	55
220	33		S-D	3	5	No	925.47	55
220	22		S-D	3	50	Yes	1,632.54	55
220	22		S-D	1	50	Yes	744.47	55
220	16	33/60	S-D	1	240	Yes	1,383.60	55
220	11		S-D	3	100	Yes	2,415.16	55
220	11		S-D	3	70	Yes	1,955.02	55
220	11		S-D	3	60	Yes	1,801.64	55
220	11		S-D	3	12	Yes	1,065.42	55
220	11		S-D	3	10	Yes	1,034.75	55
110	66		D-S	3	60	Yes	1,184.96	55
110	66		D-S	3	55	Yes	1,119.64	55
110	66	11/10	A	1	30	No	498.89	55
110	66	11/10	A	1	20	No	456.02	55
110	66	11/10	A	1	15	No	434.58	55
110	50		D-S	3	30	No	835.05	55

HV	LV	TV/ MVA	Vector	Phase	MVA 3ph	OLTC	Maximum Value ($000)	Maximum Life (years)
110	50		D-S	1	30	No	451.61	55
110	50		D-S	1	20	No	400.28	55
110	50		D-S	1	15	No	374.61	55
110	50		D-S	1	14.1	No	369.99	55
110	50		D-S	3	10	No	663.97	55
110	50		D-S	1	10	No	348.94	55
110	33		D-S	3	120	Yes	1,803.28	55
110	33		D-S	3	100	Yes	1,628.28	55
110	33		D-S	1	100	Yes	797.40	55
110	33		D-S	3	75	Yes	1,403.33	55
110	33		D-S	3	70	Yes	1,358.33	55
110	33		D-S	3	60	Yes	1,268.35	55
110	33		D-S	3	60	Yes	1,268.35	55
110	33		D-S	1	50	No	555.42	55
110	33		D-S	3	50	No	1,084.92	55
110	33		D-S	3	40	Yes	1,088.38	55
110	33		D-S	1	40	No	512.97	55
110	33		D-S	3	38	No	968.60	55
110	33		D-S	3	35	Yes	1,043.38	55
110	33		D-S	1	30	Yes	477.53	55
110	33	11/10	D-S	1	30	No	487.33	55
110	33		D-S	3	30	Yes	1,033.22	55
110	33	11/10	D-S	3	30	No	1,067.96	55
110	33		D-S	3	28	No	871.67	55
110	33		D-S	1	27.5	No	459.92	55
110	33		D-S	3	25	Yes	953.41	55
110	33		D-S	1	20	No	428.08	55
110	33		D-S	3	20	No	859.65	55
110	33		D-S	3	20	Yes	908.41	55
110	33		D-S	3	18	Yes	890.41	55
110	33		D-S	3	15	Yes	833.57	55
110	33		D-S	1	10	No	389.00	55
110	22		D-S	3	50	Yes	1,193.51	55
110	22		D-S	1	50	Yes	604.07	55
110	22		D-S	3	30	Yes	945.94	55
110	22		D-S	1	30	Yes	449.90	55
110	11		D-S	3	60	Yes	1,322.73	55
110	11		D-S	3	50	Yes	1,201.15	55
110	11	33/20	S-D	3	50	Yes	1,253.74	55
110	11		D-S	3	40	Yes	1,078.51	55
110	11		D-S	1	30	No	449.01	55
110	11		D-S	3	30	Yes	955.85	55
110	11		D-S	1	30	Yes	483.78	55
110	11		D-S	3	28	No	884.29	55
110	11		D-S	1	28	No	441.09	55
110	11		D-S	3	27	Yes	919.07	55
110	11		D-S	1	27	Yes	472.31	55
110	11		D-S	3	25	Yes	894.53	55
110	11		D-S	1	25	Yes	461.26	55

HV	LV	TV/ MVA	Vector	Phase	MVA 3ph	OLTC	Maximum Value ($000)	Maximum Life (years)
110	11		D-S	3	20	Yes	836.52	55
110	11		D-S	1	20	Yes	433.65	55
110	11		D-S	3	15	Yes	771.89	55
110	11		D-S	3	10	Yes	710.56	55
110	11		D-S	1	10	Yes	396.65	55
110	11		D-S	1	8	Yes	367.36	55
110	11		D-S	3	7.5	Yes	679.90	55
110	11		D-S	1	7.5	Yes	364.60	55
110	11		D-S	3	5	Yes	649.24	55
110	11		D-S	1	5	Yes	350.79	55
110	11		D-S	1	4.5	No	349.28	55
110	11		D-S	3	4	No	636.19	55
110	11		D-S	3	3	Yes	624.72	55
110	11		D-S	1	2.25	Yes	322.44	55
110	11		D-S	3	1	Yes	597.94	55
66	33		D-S	3	60	Yes	1,113.53	55
66	33		D-S	3	45	Yes	958.40	55
66	33		D-S	3	40	Yes	906.68	55
66	33		D-S	3	20	Yes	699.83	55
66	33		D-S	1	20	Yes	377.70	55
66	33		D-S	3	16	Yes	658.46	55
66	33	11/7.5	A	1	15	No	429.14	55
66	33		D-S	3	15	Yes	648.12	55
66	33		D-S	3	10	Yes	596.41	55
66	33		D-S	3	9	No	537.82	55
66	33		D-S	3	5	Yes	544.69	55
66	33		D-S	1	5	No	260.90	55
66	11		D-S	3	45	Yes	999.11	55
66	11		D-S	3	40	Yes	946.53	55
66	11		D-S	3	30	Yes	841.35	55
66	11		D-S	1	30	Yes	433.23	55
66	11		D-S	3	20	Yes	736.17	55
66	11		D-S	1	20	Yes	366.69	55
66	11		D-S	3	16.5	Yes	699.35	55
66	11		D-S	3	10	Yes	630.99	55
66	11		D-S	1	10	Yes	300.15	55
66	11		D-S	3	5	Yes	578.40	55
66	11		D-S	1	5	Yes	266.88	55
66	11		D-S	1	3.75	No	217.70	55
66	11		D-S	3	3	Yes	557.36	55
66	11		D-S	1	3	Yes	253.57	55
66	11		D-S	3	1	No	361.75	55
66	11		D-S	3	0.5	Yes	531.07	55
50	33		S-S	3	5	No	477.81	55
50	33		S-S	1	5	No	260.90	55
50	11		D-S	1	15	Yes	350.09	55
50	11		D-S	3	7.5	Yes	558.83	55
50	11		D-S	1	7.5	Yes	288.76	55
50	11		D-S	1	5	Yes	268.32	55

HV	LV	TV/ MVA	Vector	Phase	MVA 3ph	OLTC	Maximum Value ($000)	Maximum Life (years)
50	11		D-S	1	3	No	189.88	55
50	11		D-S	1	2.25	No	219.93	55
50	11		D-S	3	2	Yes	438.30	55
33	11		D-S	3	20	Yes	562.58	55
33	11		D-S	3	15	Yes	540.10	55
33	11		D-S	3	13	Yes	531.12	55
33	11		D-S	3	10	No	524.19	55
33	11		D-S	1	10	No	286.45	55
33	11		D-S	3	7.5	Yes	506.39	55
33	11		D-S	3	5	Yes	495.15	55
33	11		D-S	3	2.25	No	357.38	55
33	11		D-S	3	2	No	352.00	55
11	11		A	3	4.5	Yes	494.52	55

Oil Containment

Oil containment is costed based upon the capacity of the facility.

Table B. 5: Oil Containment Building Block Costs

Capacity (m^3)	Description	Maximum Value ($000)	Maximum Life (years)
10	Oil Containment System	68.78	45
15	Oil Containment System	75.24	45
18	Oil Containment System	76.83	45
25	Oil Containment System	80.52	45
30	Oil Containment System	83.16	45
35	Oil Containment System	85.79	45
40	Oil Containment System	88.43	45
45	Oil Containment System	91.07	45
50	Oil Containment System	93.60	45
55	Oil Containment System	96.34	45
60	Oil Containment System	98.98	45
65	Oil Containment System	101.62	45
70	Oil Containment System	104.26	45
75	Oil Containment System	106.90	45
80	Oil Containment System	109.53	45
85	Oil Containment System	112.17	45
90	Oil Containment System	118.46	45
115	Oil Containment System	128.00	45
160	Oil Containment System	149.02	45

Switchgear

Table B. 6: Switchgear Building Block Costs

kV	Description	CB qty	Bus Type	Out/ In	Maximum Value ($000)	Maximum Life (years)1
220	1.5 Line Breaker	1	SB	O	947.20	45
220	1.5 Half Breaker	1	-	O	763.64	45
220	1.5 Transformer Breaker	1	SB	O	631.59	45
220	Transmission Line - No Bus	1	-	O	754.35	45
220	Transmission Line - Single Bus	1	SB	O	835.37	45
220	Transmission Line - Double Bus	1	DB	O	985.22	45
220	Transmission Line - Triple Bus	1	TB	O	1,183.52	45
220	Connection Circuit - No Bus	1	-	O	361.78	45
220	Connection Circuit - Single Bus	1	SB	O	442.80	45
220	Connection Circuit - Double Bus	1	DB	O	592.65	45
220	Connection Circuit - Triple Bus	1	TB	O	790.95	45
220	Generator - No Bus	0	-	O	68.23	45
220	Generator - Single Bus	0	SB	O	149.24	45
220	Generator - Double Bus	0	DB	O	299.09	45
220	Generator - Triple Bus	0	TB	O	497.40	45
220	Bus Section	1	SB	O	418.20	45
220	Bus Coupler - Dual Bus	1	DB	O	980.02	45
220	Bus Coupler - Triple Bus	1	TB	O	1,057.88	45

~~*Approach:*~~

~~1~~ Some components of switchgear, in particular infrastructure, currently has a life of 55 years

kV	Description	CB qty	Bus Type	Out/ In	Maximum Value ($000)	Maximum Life (years)1
110	Transmission Line - No Bus	1	-	O	403.29	45
110	Transmission Line - Single Bus	1	SB	O	476.75	45
110	Transmission Line - Double Bus	1	DB	O	668.04	45
110	Connection Circuit - No Bus	1	-	O	251.62	45
110	Connection Circuit - Single Bus	1	SB	O	325.08	45
110	Connection Circuit - Double Bus	1	DB	O	516.37	45
110	Incomer - No Bus	1	-	O	251.62	45
110	Incomer - Single Bus	1	SB	O	325.08	45
110	Incomer - Double Bus	1	DB	O	516.37	45
110	Generator - No Bus	0	-	O	50.55	45
110	Generator - Single Bus	0	SB	O	124.01	45
110	Generator - Double Bus	0	DB	O	315.31	45
110	Bus Section	1	SB	O	283.42	45
110	Bus Coupler	1	DB	O	836.95	45
110	Bus VT		-	-	46.11	45
66	Transmission Line - No Bus	1	-	O	389.79	45
66	Transmission Line - Single Bus	1	SB	O	454.11	45
66	Transmission Line - Double Bus	1	DB	O	630.83	45
66	Connection Circuit - No Bus	1	-	O	245.48	45
66	Connection Circuit - Single Bus	1	SB	O	309.80	45
66	Connection Circuit - Double Bus	1	DB	O	486.52	45

kV	Description	CB qty	Bus Type	Out/ In	Maximum Value ($000)	Maximum Life (years)1
66	Incomer – No Bus	1	-	O	245.48	45
66	Incomer – Single Bus	1	DB	O	309.80	45
66	Incomer – Dual Bus	1	DB	O	486.52	45
66	Generator – No Bus	0	-	O	48.00	45
66	Generator – Single Bus	0	SB	O	112.32	45
66	Generator – Double Bus	0	DB	O	289.04	45
66	Bus Section	1	SB	O	275.89	45
66	Bus Coupler	1	DB	O	791.92	45
66	Bus VT		-	-	38.96	45
50	Transmission Line – No Bus	1	-	O	386.53	45
50	Transmission Line – Single Bus	1	SB	O	446.23	45
50	Connection Circuit - No Bus	1	-	O	244.78	45
50	Connection Circuit - Single Bus	1	SB	O	304.48	45
50	Incomer – No Bus	1	-	O	244.78	45
50	Incomer – Single Bus	1	SB	O	304.48	45
50	Bus Section	1	SB	O	275.13	45
50	Bus Coupler	1	DB	O	0.00	45
50	Bus VT		-	-	38.96	45
33	OD Feeder – No Bus	1	-	O	221.22	45
33	OD Feeder – Single Bus	1	SB	O	245.40	45
33	OD Feeder – Dual Bus	1	DB	O	283.55	45
33	OD Incomer – No Bus	1	-	O	202.74	45
33	OD Incomer – Single Bus	1	SB	O	223.62	45
33	OD Incomer – Dual Bus	1	DB	O	261.77	45
33	OD Bus Section	1	SB	O	194.96	45
33	OD Bus Coupler	1	DB	O	243.33	45
33	OD Bus VT		-	-	0.00	45

kV	Description	CB qty	Bus Type	Out/ In	Maximum Value ($000)	Maximum Life (years)1
33	Recloser	1	ACR	O	45.21	45
11	OD Feeder - Single Bus	1	SB	O	81.44	45
11	OD Feeder - Dual Bus	1	DB	O	98.66	45
11	OD Incomer - Single Bus	1	SB	O	94.24	45
11	OD Incomer - Dual Bus	1	DB	O	110.51	45
11	OD Bus Section	1	SB	O	90.05	45
11	OD Bus Coupler	1	DB	O	102.54	45
11	Recloser	1	ACR	O	36.43	45
33	Circuit Breaker - Indoor Bus Coupler	1	DB	I	128.80	45
33	Circuit Breaker - Indoor Bus Section	1	SB	I	99.57	45
33	Circuit Breaker - Indoor Feeder	1	SB	I	86.77	45
33	Circuit Breaker - Indoor Feeder - Double Bus	1	DB	I	127.40	45
33	Circuit Breaker - Indoor Incomer	1	SB	I	92.77	45
33	Circuit Breaker - Indoor Incomer - Double Bus	1	DB	I	131.50	45
22	Circuit Breaker - Indoor Bus Coupler	1	DB	I	120.70	45
22	Circuit Breaker - Indoor Bus Section	1	SB	I	87.65	45
22	Circuit Breaker - Indoor Feeder	1	SB	I	83.25	45
22	Circuit Breaker - Indoor Feeder - Double Bus	1	DB	I	119.90	45
22	Circuit Breaker - Indoor Incomer	1	SB	I	84.45	45
22	Circuit Breaker - Indoor Incomer - Double Bus	1	DB	I	124.20	45

kV	Description	CB qty	Bus Type	Out/ In	Maximum Value ($000)	Maximum Life (years)1
11	Circuit Breaker 500MVA - Indoor Bus Coupler	1	DB	I	107.77	45
11	Circuit Breaker 500MVA - Indoor Bus Section	1	SB	I	71.07	45
11	Circuit Breaker 500MVA - Indoor Feeder	1	SB	I	69.47	45
11	Circuit Breaker 500MVA - Indoor Feeder - Double Bus	1	DB	I	107.37	45
11	Circuit Breaker 500MVA - Indoor Incomer	1	SB	I	73.47	45
11	Circuit Breaker 500MVA - Indoor Incomer - Double Bus	1	DB	I	110.67	45
11	Circuit Breaker 750MVA - Indoor Bus Coupler	1	DB	I	232.96	45
11	Circuit Breaker 750MVA - Indoor Bus Section	1	SB	I	98.57	45
11	Circuit Breaker 750MVA - Indoor Feeder	1	SB	I	95.57	45
11	Circuit Breaker 750MVA - Indoor Feeder - Double Bus	1	DB	I	195.16	45
11	Circuit Breaker 750MVA - Indoor Incomer	1	SB	I	145.57	45
11	Circuit Breaker 750MVA - Indoor Incomer - Double Bus	1	DB	I	274.96	45

Reactive Power Plant

Table B. 7: Reactive Power Plant Building Block Costs

Description	**Maximum Value ($000)**	**Maximum Life (years)**2
110 kV Two Zone Bus Protection	130.51	15
220 kV Two Zone Bus Protection	130.51	15
66 kV Two Zone Bus Protection	130.51	15
Neutral Earthing Resistor 11kV 12.5 ohms 500A	66.00	45
Neutral Earthing Resistor 22kV 25 ohms 500A	71.00	45
Neutral Earthing Resistor 33kV 37.5 ohms 500A	76.00	45
Neutral Earthing Resistor 17.5kV 2 ohms 300A	66.00	45
Neutral Earthing Resistor 17.5kV 2 ohms 1500A	76.00	45
Neutral Earthing Resistor 17.5kV 2 ohms 3000A	86.00	45
Neutral Earthing Resistor 17.5kV 2 ohms 6400A	96.00	45

Transmission Line

Table B. 8: Transmission Line Building Block Costs

kV	**Config**	**Rating**	**Conductor**	**Temp.**	**Maximum Value ($000)**	**Maximum Life (years)**3
11	scp	220	1/mink	50	36.64	55
33	dcp	315	1/hyena	50	61.98	55

Approach:

2 Life of Neutral Earthing Resistors to be confirmed
3 Transmission lines are assigned lives according to environmental factors (see B.46).

kV	Config	Rating	Conductor	Temp.	Maximum Value ($000)	Maximum Life (years)3
33	dcp	360	1/coyote	50	66.21	55
33	dcp	525	1/wolf	75	74.40	55
33	scp	220	1/mink	50	37.29	55
33	scp	315	1/hyena	50	41.09	55
33	scp	360	1/coyote	50	43.21	55
33	scp	410	1/hyena	75	41.03	55
33	scp	525	1/wolf	75	47.36	55
50	scp	220	1/mink	50	40.00	55
50	scp	315	1/hyena	50	43.80	55
66	dcst	315	1/hyena	50	112.14	55
66	dcst	410	1/hyena	75	114.37	55
66	dcst	525	1/wolf	75	137.48	55
66	dcst	640	1/goat	50	170.65	55
66	dcst	1960	2/zebra	75	318.88	55
66	dcp	290	1/mink	75	65.92	55
66	dcp	525	1/wolf	75	90.07	55
66	dcp	640	1/goat	50	115.38	55
66	scst	315	1/hyena	50	91.61	55
66	scp	220	1/mink	50	40.84	55
66	scp	315	1/hyena	50	44.64	55
66	scp	360	1/coyote	50	46.77	55
66	scp	410	1/hyena	75	44.28	55
110	dcst	315	1/hyena	50	123.14	55
110	dcst	360	1/coyote	50	128.81	55
110	dcst	410	1/hyena	75	125.92	55
110	dcst	525	1/wolf	75	141.18	55
110	dcst	640	1/goat	50	176.57	55
110	dcst	750	1/zebra	50	194.99	55
110	dcst	840	1/goat	75	180.55	55
110	dcst	980	1/zebra	75	195.41	55
110	dcst	1050	2/wolf	75	223.74	55
110	dcst	1280	2/goat	50	295.26	55
110	dcst	1500	2/zebra	50	321.20	55
110	dcst	1640	1/chukar	75	273.37	55
110	dcst	1680	2/goat	75	296.05	55
110	dcst	1960	2/zebra	75	324.84	55
110	dcp	400	1/wolf	50	97.00	55
110	dcp	525	1/wolf	75	100.14	55
110	scst	315	1/hyena	50	91.57	55
110	scst	360	1/coyote	50	96.61	55
110	scst	410	1/hyena	75	92.98	55
110	scst	525	1/wolf	75	104.48	55
110	scst	640	1/goat	50	128.46	55
110	scp	315	1/hyena	50	51.41	55
110	scp	360	1/coyote	50	53.48	55
110	scp	410	1/hyena	75	53.91	55
110	scp	525	1/wolf	75	57.02	55
110	scp	640	1/goat	50	66.05	55

kV	Config	Rating	Conductor	Temp.	Maximum Value ($000)	Maximum Life (years)3
220	dcst	750	1/zebra	50	210.54	55
220	dcst	980	1/zebra	75	212.97	55
220	dcst	1280	2/goat	50	319.92	55
220	dcst	1500	2/zebra	50	353.41	55
220	dcst	1640	1/chukar	75	307.03	55
220	dcst	1680	2/goat	75	324.31	55
220	dcst	1960	2/zebra	75	362.80	55
220	dcst	3280	2/chukar	75	538.91	55
220	scst	640	1/goat	50	132.34	55
220	scst	750	1/zebra	50	146.96	55
220	scst	980	1/zebra	75	149.87	55
220	scst	1280	2/goat	50	210.85	55

Table B. 9: Seismic adjustment factors (for substations)

Equipment Type	Zone A *(high risk)*	Zone B *(medium risk)*	Zone C *(low risk)*
Establishment	1.14	1.06	1.00
Buildings	1.02	1.01	1.00
Oil Containment	1.14	1.06	1.00
Transformers	1.04	1.02	1.00
Switchgear	1.02	1.01	1.00
Other Plant	1.02	1.01	1.00

Table B.10: Interest during construction factors

Asset Type	Factor (Annualised Rate)
Substation assets	4.0%
Transmission line assets	4.8%

APPENDIX C: OPTIMISATION FOR ELECTRICITY LINE BUSINESSES

Optimisation of the System Configuration

(a) Connection/Supply Points

Issue: Location with respect to load

Approach: Treat as fixed unless there are gross or obvious anomalies, then relocate or delete as practical taking into account the effect on the transmission/subtransmission network.

(b) Transmission/Subtransmission Lines

Issue: Number of transmission/subtransmission feeders eg duplicate circuits.

Approach: Number of transmission/subtransmission feeders eg duplicate circuits.**Substations/Zone Substations**

Issue: Location with respect of load.

Approach: Identify key users or users with special requirements.
Identify gross or obvious anomalies.
Relocate, delete or modify as practical, taking into account the effect on the transmission/subtransmission and distribution (11kV) networks.

(c) Distribution Lines

Issue: Number of inter feeder ties.

Approach: Assess in relation to system reliability standards.
Relocate, delete or modify as practical.

(d) Low Voltage Lines

Issue: Choice of configuration for low density areas (eg 2ha blocks).

Approach: Identify areas and replace low voltage with high voltage lines and substations.

(e) System Loading/Configuration

With the proviso that the optimised system should not be designed to provide better service than the system in place, the system design should take into account the following general guidelines:

(i) In urban areas distribution should normally be by open ring circuits with substations in the rings, with feeders connected to spurs from the rings. Low voltage distribution should normally be by simple radial mains.

(ii) The normal loading of primary distribution feeders in urban areas should be limited to below maximum feeder capacity. (This is to ensure that in the event of a feeder outage sufficient capacity exists on adjacent feeders for most load to be transferred.)

(iii) Normally open tie circuits should be provided between adjacent circuits around the periphery of the supply area of a zone substation.

(iv) Normally open switches should be provided between feeders from adjacent supply areas.

(v) To reduce the amount of load transferred to adjacent feeders in the event of a fault occurring at the zone substation end of a feeder, additional transfer facilities should be provided.

Transpower

Security Guidelines for Transmission Equipment Planning

Load (MW)	Basic Security	**Transmission Circuits**	Busbars	Transformers
Less than 10	n	One circuit	One bus or bus section	1 x 3-phase units
(10 to 40, if more than 40km remote and local generation can limit load shed to 25%)	n	One circuit	One bus or bus section	4 x 1-phase or 1 x 3-phase unit, if backed up from alternative supply point

From 10 to 300	n-1	Two circuits	Two busbars or bus sections	7 x 1-phase units <u>or</u> 2 x 3-phase units. Firms supply of peak demand using any short term overload capability.
Load (MW)	<u>Basic</u> <u>Security</u>	**Transmission Circuits**	<u>Busbars</u>	<u>Transformers</u>
More than 300	n-2	Three circuits on at least two routes	One redundant bus or bus section, such that supply is not lost after a single contingency while one bus is out of service for maintenance	7 x 1-phase units <u>or</u> 2 x 3-phase units Firms supply of peak demand using any short term overload capability
More than 600	Loss of station	Supply into region should be diversified across more than one major terminal substation		

Optimisation of Elements in the System

(a) Transmission/Subtransmission Lines and Cables

Issue: Conductor and cable size.

Approach: Determine maximum demand and load cycle.
Ratings should normally be based on the (n-1) criterion taking into account any cyclic or limited cyclic ratings and fault level ratings. Resize the conductor to the appropriate standard size if necessary, based on meeting reasonably predictable 'system normal' maximum demand with the 'economic current rating' for the conductor and 'first order contingency' loads with the thermal rating of the conductor. Economic current ratings are usually in the range of 25–50% of the thermal rating.

(b) Substations/Zone Substations

Issue: Transmission/subtransmission voltage bus configuration.

Approach: Dependent on transmission/subtransmission configuration, should only be necessary to optimise if transmission/subtransmission system is changed.

Issue: Distribution voltage bus configuration.

Approach: Standard switch bays to be defined in asset types, optimise to nearest standard rating to match load.

Issue: Buildings.

Approach: Optimise if overdesigned for application and/or location.

Issue: Ancillary equipment.

Approach: Delete if not required.

Issue: Fire protection and oil retention facilities.

Approach: Include unless not required for application and/or location.

(c) Substation/Zone Substation Transformers

Issue: Transformer rating.

Approach: Ratings should normally be based on the (n-1) criterion taking into account any cyclic or limited cyclic ratings and fault level ratings. Determine nominal, forced cooled, cyclic and limited cyclic ratings. Check basis of rating. Optimise if ratings excessive for loads eg force cooled transformers may be used to achieve emergency ratings rather than having naturally cooled transformers in parallel. Reasonable utilisation factors are of the order of 80%, depending on the nature of the load and its projected growth.

Issue: Cable or circuit breaker constraints.

Approach: Derate transformers to cable or circuit breaker ratings if they are a limited on transformer rating.

(d) Medium Voltage Distribution

Issue: Conductor and cable size.

Approach: Examine planning and rating rules taking into account ‘economic ratings’, thermal ratings, security requirements, faults and current levels to determine minimum conductor size for each area.

(e) Medium Voltage Switchgear

Issue: Number of size and type.

Approach: Determine need for switch in relation to system reliability and system rating standards. Where excessive reduce, delete or modify.

(f) Voltage Control Devices

Issue: Degree of control.
Manual and on load tap changes.
Line regulators, line drop compensation.
Reactive compensation.

Approach: Check requirements and optimise as necessary.

(g) Distribution Transformers (pole, kiosk, ground types)

Issue: Transformer rating.

Approach: Determine average or typical power utilisation factors based on annual statistics. Nature of load and projected growth should be taken into account. Optimise if ratings excessive for loads.

(h) Low Voltage Reticulation Lines and Cables

Issue: Where there is undergrounding, whether this is appropriate.

Approach: Underground reticulation should be taken as appropriate if it is required for commercial, technical, safety or legal reasons and if a prudent commercial operator were to replicate the system, they would use undergrounding. Commercial reasons may include situations where customers are prepared to accept higher tariffs as a consequence of underground reticulation. If underground portions of the system cannot be justified on any of these grounds then the optimisation process should lead to them being replaced by equivalent overhead reticulation.

Issue: Conductor and cable size.

Approach: Determine minimum conductor and cable size using standardised approach.

Issue: Services, meters and load control equipment.

Approach: Standardise to minimum requirements by part of the system and customer load.

(i) System Control

Issue: Degree of sophistication of SCADA equipment.

Approach: Determine whether equipment is appropriate for size and complexity of distribution network.

Issue: Need for load control system and degree of sophistication.

Approach: Determine whether equipment is appropriate for size and complexity of distribution network.

APPENDIX D: THE WEIGHTED AVERAGE COST OF CAPITAL (WACC)

G.1 The weighted average cost of capital (WACC) is the minimum acceptable return on investment required by lenders and shareholders. It is the weighted average cost of debt and equity funded capital and is the appropriate rate to discount future Free Cash Flows (FCF) to their Present Value (PV).

G.2 The WACC is used for EV valuation purposes. First is used in assessing whether network segment assets can sustain an Optimised Depreciated Replacement Cost (ODRC) valuation, or whether they should be valued at EV. Secondly if such assets are unable to sustain an ODRC valuation, the WACC is used to discount the future expected cash flows of those assets to calculate their PV and EV.

G.3 The WACC may be defined in alternative ways. Below a commonly used definition is presented. The handbook does not mandate the definition to be used, but whatever WACC formulation is used, it should be consistent with the formulation of the cash flows to be discounted. The WACC in this handbook has been specified from a New Zealand investor perspective. It is presented as post-investor tax to reflect New Zealand's dividend imputation regime, and it is set in nominal (not real) terms consistent with FCF.

The WACC Formula

G.4 The WACC may be determined as:

$$WACC = R_e \frac{E}{V} + R_d (1 - t_d) \frac{D}{V}$$

where: R_e = *cost of equity capital*

R_d = *cost of debt*

E = *market value of equity*

D = *market value of debt*

$V = D + E$ = *total value of business*

t_d = *investor tax rate on debt.*

Cost of Equity Capital *(R_e)*

G.5 The cost of equity capital *(R_e)* is the return required by investors to compensate them for the variability of bottom line profits. It is equivalent to a cost of capital which includes both business risk (arising from the variability of operating cash flows, and financial risk (arising from the variability of residual cash flows after paying interest payments out of uncertain profits).

G.6 R_e may be determined using the Capital Asset Pricing Model (CAPM) as:

$$R_e = R_f (1-t_d) + ß_e [R_m - R_f (1-t_d)]$$

where:

R_f	=	*risk free rate*
R_m	=	*return on the market portfolio of shares post-investor tax*
R_m-R_f $(1-t_d)$	=	*equity market risk premium post-investor tax*
$ß_e$	=	*equity beta (levered).*

G.7 The CAPM can be configured on either a pre or post-investor tax basis. The latter is theoretically superior and the handbook has adopted its use. This does not preclude the use of WACC on a pre-investor tax basis but the inputs to the WACC will differ from those discussed below.

The Risk Free Rate *(R_f)*

G.8 The most suitable risk free rate is a government stock rate, say for 5 year stock. This rate is widely available as active trading in 5 year government stock means it is likely to be an equilibrium rate, and it is the generally accepted indicator of the risk free rate.

Equity Market Risk Premium *R_m-R_f $(1-t_d)$*

G.9 The post-investor tax market risk premium can be calculated from New Zealand share market data. An estimate should be used for this factor which is both theoretically and empirically defensible. The basis of measurement should be consistent with that used for the determination of the equity beta coefficient.

Equity Beta *(b_e)*

G.10 The equity beta coefficient will depend on the relative business and financial risk of each ELB. Equity betas can be expressed in terms of a asset betas, which are a measure of relative business risk alone (the financial risk of leverage is excluded from asset betas). The relationship of equity betas to asset betas is:

$$ß_e = ß_a (1 + D/E)$$

where:

$ß_e$	=	*equity beta (levered)*
$ß_a$	=	*asset beta (unlevered).*

G.11 Asset betas can be estimated from of firms listed on the New Zealand Stock Exchange with comparable levels of business risk as well as firms listed on overseas markets.

Shares in electricity utilities are traded on a number of overseas markets. However, caution and judgement is required in applying data derived from other markets as this may be derived from capital markets which exhibit different characteristics to New Zealand capital markets.

The Cost of Debt *(R_d)*

G.12 The borrowing rate should be estimated as the risk free rate plus a premium that will reflect the riskiness of the debt of the particular line ELB:

$$R_d = R_f + Debt\ Premium.$$

The Debt and Equity Ratios *(D/V and E/V)*

G.13 The debt and equity ratios should be set consistent with ratios considered to be prudent by equity markets for comparable businesses. As well as referring to the New Zealalnd market which has limited examples of such businesses, examination of overseas markets may provide useful input.

G.14 An important factor influencing a particular firm's debt ratio is the level of business risk facing the firm. A low risk firm with stable cash flows can prudently support a high debt ratio. A firm with higher risk characteristics will normally only be able to support lower debt levels as troughs in its more volatile cash flow could create liquidity problems if debt (and therefore debt servicing cost) is relatively high.