Western Power Corporation

Physical Assets Valuation
as at 30 June 2004

Distribution and Transmission Networks

Report to the Valuation Committee

June 2004

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APPENDICES

Glossary of Terms and Definitions

ACCC	Australian Competition and Consumer Commission
ADMD	After Diversity Maximum Demand
CIS	Customer Information System
CPI	Consumer Price Index
DFIS	Distribution Facilities Information System
DORC	Depreciated Optimised Replacement Cost
DQM	Distribution Quotation Management
EAC	Equivalent Annuity Cost
EPCM	Engineering, Procurement and Construction Management
EV	Economic Value
ERV	Economic Replacement Value
HC	Historical Cost
HV	High Voltage
IDC	Interest During Construction
kVA	Kilovolt - ampere
kWh	Kilowatt Hour
LV	Low Voltage
MERA	Modern Equivalent Replacement Asset
MIMS	Mincom Information Management System
MVA	Megavolt - ampere
MW	Megawatt
NBV	Net Book Value
NWIN	North West Interconnected Distribution Network
NWIS	North West Interconnected Transmission System
O&M	Operations and Maintenance
ODRC	Optimised Depreciated Replacement Cost
ODV	Optimised Deprival Value
PwC	PricewaterhouseCoopers
RAB	Regulatory Asset Base
RC	Replacement Cost
RIN	Regional Isolated Distribution Networks
SCADA	Supervisory Control and Data Acquisition
SKM	Sinclair Knight Merz
SWIN	South West Interconnected Distribution Network
SWIS	South West Interconnected Transmission System
WACC	Weighted Average Cost of Capital
WDV	Written Down Value

1 EXECUTIVE SUMMARY

1.1 Purpose and Scope of Valuation

This valuation was initiated in order to assist in the determination of the fair values of physical assets to be transferred from Western Power to the four key Successor Entities (State Retail, State Generation, State Networks and Regional Power) into which it was proposed that Western Power be disaggregated. The enabling legislation (the Electricity Corporations Bill 2003) to disaggregate Western Power into four key operating entities was withdrawn from the Legislative Council of the Western Australian Parliament in March 2004 as agreement could not be reached with opposition parties for its passage.

The valuation of the Network assets also is to be used for regulatory purposes. Access to Western Power's transmission and distribution networks is currently provided to third parties under the access regime implemented in 1997. The access pricing arrangements are based upon, amongst other parameters, application of a real pre-tax weighted average cost of capital to a value ascribed to the regulatory asset base. Draft legislation before the Western Australian Parliament as at the date of this report will introduce transitional provisions for the continuation of third party access to Western Power’s transmission and distribution networks until a new Electricity Access Code is developed.

One of the changes which will be affected under this draft legislation is transfer of responsibility for access pricing to the Economic Regulatory Authority. It is understood that the State of Western Australia has the discretion, in accordance with the national agreements, to elect to become subject to the jurisdiction of the Australian Energy Regulator in respect of economic regulation of electricity transmission and possibly distribution networks.

The transmission and distribution networks currently operate under a three year regulatory period but with annual aggregated revenue requirement calculations. The regulatory asset base, target rate of return and transmission and distribution access prices are re-determined annually through a roll-forward mechanism between periodic valuations. The last periodic valuations were undertaken as at 30 June 2000.

Following withdrawal of the Electricity Corporations Bill 2003, the primary purpose of this report is to provide a periodic valuation of the transmission and distribution networks for the purpose of determining network access prices. However, the valuations will also be used to assist in the assessment of asset carrying values and for economic modelling.

1.2 Methodology Applied

The Optimised Deprival Value (ODV) method is the prescribed methodology in Western Power’s Distribution and Transmission Access Arrangements for the valuation of the network assets for the purpose of determining access prices.

Although this valuation methodology is considered to be the most appropriate and objective method for valuing such assets, the detailed process is specific to each asset base being valued. A universal approach cannot be applied to every regulated asset base - each asset base has unique characteristics and circumstances which require analysis to determine the most appropriate valuation procedure. The approach adopted for particular issues can significantly impact the value of the assets. The valuation assessment in this report has been based upon what PricewaterhouseCoopers ("PwC") and Sinclair Knight Merz ("SKM") believe to be a robust, transparent and clearly defined approach to material issues using current regulatory and commercial valuation best practice. The valuation methodology adopted as agreed with the Valuation Committee established by the Electricity Reform Implementation Unit is set out at Appendix A of this report.

In addressing these methodology issues, consideration has been given to:

- the views of utilities regulators in other States of Australia;
- Western Power's prior valuation approach to particular issues;
- the historical development of assets and legislation surrounding the development of the distribution and transmission networks in Western Australia; and
- regulatory principles and requirements both in Western Australia and other States.

The ODV and DORC values determined in this report are also suitable for accounting valuation purposes subject to the application of recoverable amount tests (refer Section 1.15 of the valuation methodology set out at Appendix A).

The DORC assessment whilst considering performance and reliability aspects of the Distribution and Transmission networks in order to value assets on a like for like basis, does not specify whether service delivery standards are being met. Where service standards are exceeded through over design or over-capacity of assets, the assets are optimised to a level which meets existing service standards. Where service standards are not met through asset design or condition the assets are valued as currently installed.

1.3 Valuation Summary

This report represents a valuation of Western Power's physical transmission and distribution infrastructure assets as at 30 June 2004 on a DORC and ODV basis. The transmission networks asset base as at 30 June 2004 has been estimated based on anticipated project completion to 30 June 2004. The distribution networks asset base has been based on physical assets recorded in the operational asset register as at 31 December 2003 plus actual capital expenditure to 31 March 2004 and estimated capital expenditure for the remaining three months.

The total value for the distribution network assets on a DORC and ODV basis is estimated at $2,137 million and $2,136 million respectively. The total value for the transmission network assets on a DORC and ODV basis is estimated at $1,302 million and $1,286 million respectively.

Summaries of the current valuations are set out below.

Summary of DORC and ODV for Distribution Networks at 30 June 2004

	South West Inter-connected Network		*North West Inter-connected Network*	*Regional Isolated Networks*	*Total Distribution Networks*	
	DORC $ million	*ODV $ million*	*DORC/ODV $ million*	*DORC/ODV $ million*	*DORC $ million*	*ODV $ million*
Lines and cables	1,178.9	1,177.3	22.8	91.1	1,292.8	1,291.2
Transformers	253.1	253.1	5.2	13.9	272.2	272.2
Switchgear	117.8	117.8	2.2	6.3	126.3	126.3
Meters	162.8	162.8	3.1	4.6	170.5	170.5
Streetlights	78.5	78.5	1.0	1.6	81.1	81.1
Assets to be entered in registers at December 2003	40.6	40.6	0.9	2.2	43.7	43.7
Estimated additions to 30 June 2004	66.2	66.2	1.4	2.2	69.8	69.8
Total network assets	1,897.9	1,896.3	36.6	121.9	2,056.4	2,054.8
Other assets	66.9	66.9	6.0	8.2	81.1	81.1
Total Distribution Network Value	1,964.8	1,963.2	42.6	130.1	2,137.5	2,135.9

An amount of $1.6 million of economic optimisation has been applied to the DORC assessment of the Distribution Networks. Accordingly, the ODV and DORC values are substantially the same.

Summary of DORC and ODV for Transmission Networks at 30 June 2004

	DORC $ million	*ODV $ million*
South West Interconnected System		
Substations	598.8	598.8
Substation land	51.8	51.8
Transmission lines	480.7	465.6
Easements	14.7	14.7
Underground cables	10.6	10.6
Tariff metering	2.0	2.0
SCADA and communications	31.3	31.3
Other non-system assets	16.1	16.1
Total South West Interconnected System	1,206.0	1,190.9

	DORC *$ million*	*ODV* *$ million*
North West Interconnected System		
Substations	41.6	41.6
Transmission lines	50.4	50.4
SCADA and communications	0.5	0.5
Other assets	3.1	3.1
Total North West Interconnected System	95.6	95.6
Total Transmission Network Value	1,301.6	1,286.5

The process of determining these valuations is complex and there has been extensive reliance on information provided by Western Power in undertaking this assessment. The information provided by Western Power has not been subject to independent audit. The nature of the infrastructure, the number of components and the valuation methodology has, by necessity, involved some degree of approximation and judgement. Accordingly, whilst we consider the above assessment to be reasonable, we recognise and highlight that the uncertainties and judgmental issues inherent in the assessment will create a valuation range for the distribution infrastructure assets above and below the amount of our determination.

We consider that the general level of accuracy of estimation within the resultant valuation assessments to be ±10%.

The current assessments represent a 23.8% and 29.0% increase in value from the equivalent 2000 assessments for SWIN distribution and SWIS transmission respectively. Comparisons of the current valuations with the 2000 assessments are set out in Section 5 of this report.

Parts of the Eastern Goldfields transmission system within the South West Interconnected System are subject to joint ownership. For regulatory purposes, the full asset value is recognised within the regulatory ODV.

For accounting purposes, the carrying value of the relevant Eastern Goldfields assets should be reduced proportionate to the private ownership interest.

The privately owned portion of the Eastern Goldfields transmission system is as follows:

	RC *$ million*	*DRC* *$ million*	*ORC* *$ million*	*DORC* *$ million*	*ODV* *$ million*
Private Portion of Lines	22.6	14.8	22.6	14.8	10.8
Private Portion of Substations	18.3	10.3	18.3	10.3	10.3
Total private portion	40.9	25.1	40.9	25.1	21.1

Accordingly, for accounting purposes the DORC of the SWIS reduces to $1,180.9 million and the ODV of the SWIS reduces to $1,169.8 million.

1.4 Key Assumptions and Issues

Details of the key assumptions made in undertaking the valuation together with significant methodology issues and their resolution are set out in the text of this report. The following matters are particularly relevant to our assessment:

- MERA replacement costs have been determined on the basis of replacement of components of the networks in the ordinary course of business rather than wholesale replacement of the infrastructure;

- asset ages have been estimated for a significant component of the high and low voltage distribution lines where the asset registers do not contain sufficient information. Asset ages have been estimated by reference to ancillary equipment such as meters or specific assessments of asset age by Western Power as appropriate;

- easements have been included at historic cost;

- non-system assets which are not individually material have principally been included on the basis of their net book value; and

- the valuation includes contributed assets.

2 SOURCES OF INFORMATION

In the preparation of this report, we have had access to the following principal sources of information:

Distribution Networks

- Distribution Facilities Information System (DFIS);
- Register of Non DFIS Items;
- Register of Non System Items;
- DFIS High Voltage Switching Diagrams;
- Distribution Construction Manual;
- Distribution Quotation Management (DQM) system outputs;
- Methodology to determine average age of distribution feeder;
- Transmission peak load readings;
- Networks Business Unit, Overhead Cost Allocation Policy and Process;
- Excel worksheets applying building block costs to asset listings; and
- Maintenance Records, Karratha Lines.

Transmission Networks

- the Transmission Plant Maintenance System database;
- the Transmission Line Register and Substation Register;
- Transmission operation single line diagrams;
- Transmission peak load ratings; and
- Excel worksheets applying building block costs to asset listings.

We have also had the benefit of discussions with a number of Western Power staff including:

Perth	Peter Mattner David Tovey Neil Gibbney Mark McKinnon Bill Bignall Rob Walker Walter Dandridge Peter Brazendale Glen Pearce Peter Martino Brian Jones Al Edgar
Karratha	Alan Porter
Albany	Carl Swarbrick

3 ASSET IDENTIFICATION AND VERIFICATION

3.1 Distribution and Transmission Network Assets

The electricity distribution network is defined in the Western Power Distribution Access Arrangements as “that part or those parts of the system operating at less than 66kV and at a nominal frequency of 50 Hz”. Western Power has two interconnected electricity networks, the South West Interconnected Network (SWIN) and the North West (Pilbara) Interconnected Network (NWIN). Western Power also operates many Regional Isolated Networks (RIN) supplied from power stations that are not interconnected.

Western Power has two separate transmission networks namely the South West Interconnected System (SWIS) and the North West Interconnected System (NWIS). The principal elements of the transmission networks include transmission substations and zone substations, interconnected by transmission and sub-transmission lines. The transmission networks enable the transportation of electricity from power stations to zone substations and high voltage customer loads. The zone and customer substations provide the interface between the transmission networks and distribution networks.

Further details of the transmission and distribution networks are set out in Sections 2.1 and 2.4 of the methodology document at Appendix A.

3.2 Asset Registers

Detailed operational transmission and distribution equipment registers are maintained separate to Western Power’s financial asset registers. These operational equipment registers contain detailed information on the underlying assets including, their ages and configuration. These operational equipment and financial asset registers form the base for our valuation assessment.

The primary asset registers used are listed in Sections 2.2 and 2.5 of Appendix A, together with commentary on Western Power’s mechanisms for updating these registers. SKM has found that generally the registers offer a readily identifiable and traceable record. Western Power has taken steps to further improve the quality of data in the DFIS register where there is incomplete asset data, but some element of estimation of asset ages and asset specification remains. This is considered further in Section 4.4 of this report. Transmission line and substation registers are maintained as Excel spreadsheets and benefit from the flexibility of amending or adding entries as needed.

There is a lag in the updating of the operational equipment registers (upon which the valuation is based) for changes in the asset base including new additions. This lag is of significance for distribution assets where (unlike the transmission access arrangements) the distribution access pricing regime does not provide an allowance for interest during construction. As such, an allowance needs to be made in the valuation for expenditure incurred on assets which has not yet been included in the operational equipment register. The allowances made are separately identified in Section 4.7.

Additions to the transmission operational asset registers are generally large discrete projects. For the purposes of this assessment, asset data from the transmission operational asset register as at 31 December 2003 has been updated for known projects to be completed over the period to 30 June 2004. This effectively updates the transmission operational assets to 30 June 2004.

A similar update has not been possible for the distribution networks due to the multitude of small projects over the period to 30 June 2004. Accordingly, the operational asset register at 31 December 2003 has been used as the basis for the DORC and ODV assessment, to which estimated capital expenditure over the period to 30 June 2004 has been added. This expenditure is separately identified in Section 4.7.

Various separate non-system asset records are maintained by Western Power. The non-system assets include SCADA and communications equipment, land holdings, buildings and miscellaneous items. Asset information is predominantly based on MIMS financial data or supporting records.

3.3 Asset Verification and Site Inspections

An asset verification process was carried out to check the accuracy and completeness of the asset registers which form the basis of the valuation.

3.3.1 Distribution Networks

Extent of Verification

The scale and nature of development of DFIS means that it has not been possible to examine the data sources that were used to produce DFIS. It has therefore been necessary to accept some aspects of DFIS at face value. Sample checks of the database have been made to provide evidence that the quantities in DFIS are reasonable. These checks have shown that there are some minor inaccuracies in DFIS. However, based on the testing performed these are unlikely to have any material effect on the valuation.

Although recently installed assets have accurate installation data recorded in the relevant systems, historically the date of installation was not recorded when assets were installed. The lack of installation dates for older assets means that the actual age of significant proportion of assets is not known. Accordingly, some estimation of distribution feeder asset age is required where age data has not been maintained. Similarly, some estimation of component specifications is required where such information has not been recorded. Whilst there are substantial shortcomings in data on asset ages, the incidence of incomplete recording of asset specifications is very low. Minimum size defaults have been applied when specifications are not recorded. An agreed ageing formula has been applied to distribution feeders to overcome determination of asset age where such information is not known (refer Appendix B-3). This formula uses the data on meter ages held in the Customer Information System which has more reliable data. A conservative assessment is then made from the average age of the meters on each feeder. This method is considered to provide a reliable estimate of the feeder ages.

The lack of complete information on asset age is common for many long established utilities and is not unique to Western Power. In other jurisdictions, pole ages are used as a proxy for distribution feeder age. In general, an average pole age is applied to all feeders, although in some cases, average pole age is determined on an individual feeder basis. This method is analogous to the meter aging method adopted by Western Power.

A comparison of total physical quantities of major distribution asset categories within the SWIN has been undertaken between the valuation dates of June 2000 and June 2004 (based on DFIS as at 31 December 2003) to assess the reasonableness of the total asset base having regard to additions and deletions in the intervening period.

This comparison for the SWIN may be summarised as follows:

		June 2000	***Current Assessment***[1]
Distribution feeders	Numbers	591	638
	Lengths	76,693km	80,364km
Distribution transformers	Numbers	53,680	56,965
	total KVA	4,748MVA	5,235MVA
Low voltage feeders	Lengths	16,002km	18,017km
SWER lines	Lengths	38,399km	38,761km

1 *Effective as at 31 December 2003.*

The volume of data stored in the asset registers is very significant therefore a sampling technique was used to verify the data for the purposes of this asset valuation.

The sample of system assets was chosen at random from the asset database and verified in the field as to existence, age and condition. Similarly, a sample of assets was identified from the field and located in the database.

Assets not Contained in DFIS

There was no physical inspection of the distribution network assets not contained in DFIS, such as steel reinforcement for poles. Customer meters are recorded separately within the Customer Information System.

Extent of Physical Inspection

The following table lists the sample of distribution feeders that were inspected from ground level against the DFIS HV switch diagrams.

System	*Zone Substation*	*Feeder*
SWIN	Bunbury Harbour	Bunbury North
	Bunbury Harbour	Carey Park
	Katanning	Ravensthorpe
	Wanneroo	Lakeside
	Shenton Park	Stubbs Terrace South
	Kalamunda	Lesmurdie
	Armhurst	Watkins
	Byford	George & Alexander Road
	Canningvale	Baile Road
	Wagin	Dumbleyung
	Albany	Timewell
	Albany	Denmark
NWIN	Bulgarra	Millstream East
	Pegs Creek	Millstream West
Regional	Hopetoun	Hopetoun
	Esperance	Dalyup

The number of feeders visited in the 2000 and 2004 valuations were:

	2000	*2004*
SWIN	12	12
NWIN	3	2
RIN	2	2

Verification Procedures

Each selected feeder was physically checked against the DFIS HV switching diagram. Each feeder was checked for verification of pole top switches, dropout fuses, transformers and underground cable connections to the degree consistent with a ground level survey.

The condition of the equipment was reviewed for verification that appropriate maintenance was being provided to ensure the economic life of the line was achievable. The condition of plant was also used as an indicator of age.

The nature of the equipment and the associated overhead lines or cables were in turn checked against the corresponding entries in the asset registers. At all of the locations visited, the plant installed agreed with the asset register.

A sample verification check was also performed to ensure that asset records have been updated where overhead lines have been removed through the undergrounding program.

Conclusions

In general, the distribution assets inspected were in fair condition and reflected the application of appropriate maintenance practices. In addition, the assets identified in the field were included in the appropriate asset categories in the database. The format of the asset registers facilitates their maintenance at a high standard apart from the aforementioned issues over the lack of ages for certain assets and construction details of feeder sub-sections. The method of estimating missing feeder ages by using known meter ages is considered to be robust.

Accordingly, the Western Power asset records have been relied upon for the purposes of this valuation. Estimation procedures and conservative assumptions have been applied where the asset database does not have full information on asset age or type. SKM has found that the register offers a readily identifiable and traceable record.

3.3.2 Transmission Networks

Extent of Verification

The volume of data stored in the asset registers is very large thus a sampling technique was used to verify the data for the purposes of this asset valuation.

The verification exercise for the 1995 and 2000 asset valuation concentrated on parts of the SWIS north of Perth, generally east to Kalgoorlie and south of a line between Kalgoorlie and Perth. The NWIS has received a higher level of coverage as the network is less extensive.

There are 123 Western Power owned substations in the adjusted SWIS asset base as at 30 June 2004 (2000: 120) and 12 in the NWIS (2000: 12). The transmission network reflected in the adjusted asset base comprises approximately 7,500 kilometres of overhead lines (2000: 6,700 kilometres). The reasonableness of increases in physical assets has been assessed by reference to known new transmission asset projects since 2000.

The following substations and terminals were visited by SKM as part of the current valuation:

SWIS	
Regans	Muja
Lansdale	Collie
Yanchep	Kwinana
North Fremantle	Cockburn
Southern Terminal	Pinjar
Mandurah	
Albany	

NWIS
Karratha
Cape Lambert
Regional
Hopetoun
Esperance

The proportions of substations visited in the 1995, 2000 and 2004 valuations were:

	1995	***2000***	***2004***
SWIS	12%	20%	10%
NWIS	67%	42%	17%

Verification Procedures

The verification procedures conducted during the site inspections comprised a check of all primary plant at all voltages by visual audit against line diagrams unique to each substation. Major power station switchyards were viewed as part of the power station visits.

The opportunity was taken to review the condition of plant as an indicator of age and prospective remaining economic life. In most substations, the year of manufacture of each of the power transformers was also noted. In addition, new circuit breakers were noted at a number of substations. Modifications were introduced to the method of aging of substation bays to allow for replacement capital expenditure (refer Appendix C-3).

The nature of the substation equipment and the associated overhead lines or cables was in turn checked against the corresponding entries in the asset registers. All of the locations visited and plant installed agreed exactly with the asset register. In some cases, additional plant was observed on site in varying stages of installation. The asset registers and the regulatory asset base for the transmission network only includes equipment from the date of commissioning and therefore excludes construction in progress. It was confirmed that none of the plant noted as being on site for installation was scheduled for commissioning before 31 December 2003 and that none of these items appeared in the operating asset registers as at 31 December 2003. However, the asset base subject to valuation has been adjusted for transmission assets anticipated to be commissioned prior to 30 June 2004 and therefore this plant has been included in the transmission network valuation.

The verification process also included checks on plant known to have been decommissioned. In all cases noted, the decommissioned plant had been deleted from the asset register.

Conclusions

From the verification procedures undertaken, nothing has come to our attention to indicate that the transmission operating asset registers are not accurate. In addition, the format of the asset registers facilitates their maintenance at a high standard. Accordingly, the Western Power asset records have been relied upon for the purposes of this valuation. Both line and substation registers are maintained as customised databases and downloaded to Excel spreadsheets for the purposes of the valuation.

3.3.3 Non-System Assets

Non-system assets associated with distribution and transmission networks other than SCADA and communications equipment were not subject to detailed physical verification procedures in the current valuation due to the relatively low value attributed to these assets relative to the system assets. Internal processes adopted by Western Power to ensure completeness of these assets were subject to review. In particular, the processes adopted to ensure the accuracy of the property register and MIMS financial asset registers were subject to consideration.

4 VALUATION

4.1 Building Blocks

4.1.1 Basis of Building Blocks

The logical identifiable plant types and configurations which have been used as the basis for the allocation of MERA codes follow the framework adopted for the 1997 and 2000 valuations. The MERA assets and codes are set out in Section 2.8 of Appendix A.

For the distribution network, the basic building blocks and unit rates used in the valuation were reviewed for reasonableness and benchmarked against New South Wales Treasury Valuation rates. The unit rates and categories used in this valuation are included in Appendix B-1.

For the transmission network, the basic building blocks and unit rates developed by Western Power and used in the valuation were reviewed for reasonableness and benchmarked against SKM reference asset data. The SKM data has been used extensively for transmission utility network asset valuations in Australia and overseas. The unit rates and categories used in this valuation are included in Appendix C-1.

4.1.2 Commentary on Distribution Building Block Rates

In aggregate, the weighted average unit rates applied within the distribution networks have increased by approximately 9.0% from the 2000 assessment representing an average real price decrease. This has been particularly so for overhead lines and transformers which comprise the majority of distribution network assets. There have been larger percentage movements for some individual MERA codes and between asset types.

Overhead Lines

The base MERA costs of overhead lines within the SWIN have been recalculated by Western Power based on cost estimates derived from DQM. The MERA rates have been reviewed by SKM and fall within the ranges expected by SKM. The costs adopted in this valuation assessment have fallen in real terms since the 2000 assessment.

An allowance of $343 per kilometre for urban lines and $84 per kilometre for rural lines has been added to the rates for overhead lines in coastal areas to account for high pollution insulators and pole top bonding. These rates are applied to overhead lines within 5 kilometres of the coast in the metropolitan and south country regions and within 15 kilometres in the northern country regions. The lines with these characteristics are identified in DFIS.

Steel reinforcing of wood poles has been estimated at an average cost of $245 per pole which takes into account the variation in costs for the metropolitan and country regions.

The reinforcement of wood poles by staking with steel sections at the ground line has been in practice since the 1980's. Poles that are reinforced have been shown to provide an average wood pole with a life extension of 15 years to a revised useful life of 50 years.

Poles are reinforced on average after 20 years of a normal 35 year non-reinforced wooden pole life. To determine the current replacement cost of the steel reinforcing, current reinforcing costs have been discounted to a present value (using a risk free real rate of 3.18%) over the period up to when the reinforcing normally takes place (20 years). The resultant discounted cost of $31.5 million is depreciated over the average extended 30 year term of a reinforced pole's life from the date of reinforcement. An average remaining life of 15 years has been adopted for reinforced poles.

Underground Cables

Unit rates were calculated for each MERA category appropriate for underground cabling. The unit rates have been refined from information gained from the metropolitan undergrounding project. A separate rate is given for all high voltage underground cables in the Perth central business district.

High voltage underground cables buried with LV underground cable has been costed as HV underground on its own, based on lengths in the HV data. The accompanying LV underground cable has been costed as the LV cable cost plus an installation cost of $8.00 per metre based on lengths in the LV data.

One rate has been used for all instances where two 22kV cables are installed in a common trench because the incidence of this configuration is small. The rate for each multiple LV cable in the one trench is the rate for one cable plus an installation cost of $8.00 per metre for subsequent cables.

Transformer Substations

The rates used in the current valuation for distribution transformer substations were reviewed against the 2000 valuations. The average rate has decreased, generally due to the lower cost of transformers. There were some differences in individual categories from those used in 2000 and the net overall effect of re-costing the transformer building blocks has been to decrease the cost base by approximately 1.0%. The revised building blocks are within the range of costs identified from the benchmarking of these components against other utilities.

Regulators, capacitors and special transformers are valued separately.

The quantity of unknown transformer sizes is less than 5% of the total. Where transformer sizes are unknown in DFIS they have been assumed to be:

- 10kVA for pole mount and 25kVA for customer mount in rural areas.

- 300kVA for kiosk transformers.

Transformer prices include the cost of installation and housing. Customer housing is given a value of $2,177 per unit to cover installation but zero value for the housing itself.

Switchgear

The rates used in the previous valuation for switchgear were reviewed and updated for the 2004 valuation. There were some differences in individual categories and a net overall decrease in the cost base of 4%. Benchmarking of the revised building block costs indicates that these are within the range of costs experienced by other utilities.

Meters and Services

The unit rates for tariff meters and associated services have been reviewed and updated against the 2000 valuation rates. Overall there was a very small reduction in the unit rates. Meters and services have been valued using quantities from CIS.

Public Lighting

Unit rates used in the 2000 valuation were reviewed and updated. Benchmarking indicated the rates were within the range of costs experienced by other utilities.

NWIS and Regional Building Block Rates

Building block costs for the SWIN have been used as a basis for determining the building block rates for the NWIN and RIN. A table of building block costs for overhead lines and underground cables for the NWIN and RIN together with locational factors applied are included in Appendix B-2. All other building block costs are the same as for the SWIS.

4.1.3 Commentary on Transmission Building Block Rates

The weighted average unit rates applied throughout the transmission networks have increased in aggregate from the 2000 assessment by approximately 4% for overhead transmission lines and approximately 25% for substations. The real price reduction in overhead lines reflects the impact of importing fabricated steel for lattice steel tower construction.

SKM has carried out an overall high level comparison for all rates, as well as more detailed estimates and analysis for a sample of the more common building block types considered to have a material effect on the valuation.

The building block rates used by Western Power for overhead transmission lines, underground cables, substation establishment, reactors and capacitors are considered appropriate when benchmarked against the SKM reference assets.

For the transformer and circuit breaker bay categories, whilst there are differences in some individual unit rates, overall these differences amount to less than 3% for each category. The individual rates are generally within 10% of those SKM would have expected and this is typical of the order of accuracy obtained in estimating projects of the complexity of substations.

The principal reason for the uplift in average substation unit costs from 2000 is as a consequence of more extensive costing and benchmark data being available for the 2004 assessment. There has also been a general upward movement in substation unit rates since 2000 of approximately 10% to 12% in real terms.

Building Block Costs for Overhead Transmission Lines

The unit rates for overhead transmission line building blocks and the various adjustment factors for terrain, wind loading, foundations in coastal areas, length of line and the ratio of angle/terminal structures were reviewed with Western Power.

These unit rates have been benchmarked against actual project costs for recent Western Power overhead line projects and have been found to be in reasonable agreement. The rates reflect the MERA rates used by SKM in recent valuations for two transmission network businesses in Australia and are considered reasonable.

Cost adjustment factors were also applied to the overhead transmission line MERA unit rates to reflect the costs actually incurred where lines are located in a different environment to that assumed in the estimation of the MERA unit rate (refer Appendix C-2).

Wind load adjustment factors reflect the additional cost incurred for construction in the higher wind regions north of Geraldton and in the north west of Western Australia. The adjustment factors range between 1.04 for the Geraldton region and 1.45 for the North West coastal region.

Terrain adjustment factors recognise the additional costs associated with extra clearing and access track construction. They also recognise the additional costs associated with providing extra corrosion protection for conductors in the coastal terrain category. The terrain adjustment factors range between 1.02 for the “coastal” and “rolling” categories to 1.12 for the “hilly” category.

The MERA unit rates have been developed for overhead transmission lines of approximately 100 kilometres in length. Length adjustment factors have been applied to recognise that the unit rates should be varied where overhead transmission line lengths are significantly different from 100 kilometres. This recognises that there are certain costs in construction, such as mobilisation and de-mobilisation costs, that are independent of length. Length adjustment factors range between 0.95 for lengths greater than 150 kilometres and 2.5 for lengths of less than 5 kilometres. The line length factors have been applied based on overall start to destination line lengths based on system design rather than sectional analysis.

Western Power is faced with additional construction costs because of sandy, and sometimes wet, soil conditions in the coastal plains. This requires additional foundation works in the form of piling of lattice steel structures and sleeving of pole foundation. These additional costs are not included in the base MERA unit rates. After discussions with Western Power and a review of their costs for these activities, an adjustment factor was applied for foundations in the coastal plains of 1.07 to incorporate the additional costs associated with these areas.

The MERA unit rates are based on the overhead transmission line having a ratio of angle/termination structures to the total number of structures of 1:10. A formula was developed to adjust the MERA rates to take account of the actual proportion of angle structures for each overhead transmission network.

SKM considers that the cost adjustment factors adopted for the valuation are reasonable.

Underground Cables

As the incidence of underground cables in the transmission network is not significant, only a high level review of the MERA unit rates for underground cables was undertaken by SKM. The unit rates used in the valuation are considered to be reasonable.

Substations Costing

Western Power has undertaken a compilation of building block costs from material and labour content based on detailed internally maintained Western Power construction records. SKM has reviewed the building block rates proposed by Western Power for substation bays, transformers, buildings and establishment costs by comparison with benchmark construction costs in other jurisdictions as adjusted for asset specification and/or market considerations.

Substation Bays

Some of the substation bay unit rates initially proposed by Western Power varied significantly from those SKM would have expected. Detailed examination of Western Power substation estimates revealed substantial alignment in material costs but some significant differences in labour components. The labour unit rates used by Western Power were comparable with industry benchmarks. However, significantly more labour hours were used than expected from the benchmarking undertaken.

Investigation of the differences between the replacement cost estimates revealed that Western Power had determined replacement costs for some bays on an incremental basis. This approach took into account the additional labour costs incurred when expanding an existing, energised substation where special work practices and safety procedures have to be observed. The SKM approach considered replacement of the entire substation as one construction project.

The adoption of the replacement unit as a substation is consistent with regulatory practice in other Australian jurisdictions and has been adopted for this assessment. Accordingly, the unit rates proposed by Western Power were adjusted to reflect this situation by reducing the labour components of the estimates.

There were 10 MERA classes where the unit rates proposed by Western Power were more than 20% higher than the rates SKM would have expected. This amounted to a total of \$16.6 million. There was one MERA class where the Western Power rate was more than 20% lower than SKM would have expected, amounting to \$3 million. Other costing differences were principally found to relate to differences in specification between the Western Power assets and those benchmarked by SKM. Cost differentials against those expected by SKM for 330kV bays were initially in the order of 50% above SKM rates but reduced to less than 13% upon detailed examination. Cost differentials for the dominant bay types such as 132kV single busbar feeder and transformer bays have been resolved to within 1%. Indoor switchgear, another dominant component, has a rate 7% below the SKM benchmark. These three components make up approximately 40% of the substations valuation. When adjusting the benchmark assets to meet the Western Power asset specifications, the remaining variations in individual bay costs were considered to be immaterial. Overall, the difference in value when using Western Power rates compared with a value using SKM rates amounts to less than 3% of gross replacement cost and only 1.3% on a DORC basis (due to the older than average nature of these assets). SKM therefore considers that the total value assigned to substation bays is reasonable.

Transformers and Infrastructure

Some of the transformer unit rates used by Western Power were higher and some were lower than SKM would have expected. Overall, the difference in value for transformers amounted to less than 3%. SKM therefore considers that the total value assigned to transformers is reasonable.

4.2 Source of Building Block Rates

4.2.1 Distribution

Western Power provided the unit rates utilising its in-house estimating package known as the Distribution Quotation Management (DQM) system. The labour content of the unit rates was revised and adjusted to reflect costs applicable to open tendering for long run contracts consistent with the MERA building blocks adopted.

Labour Rates

Labour rates used in the DQM system comprise the base labour rate with allowances for items such as leave, superannuation and workers compensation insurance which in total amounts to a 42% uplift factor on base rates. The labour rate including the 42% uplift used in this valuation for a distribution employee is $27.11 per hour.

Material Rates

The materials cost estimates in the DQM system are based on annual contracts for supply of all major items with an average allowance of 12% to cover transport, warehouse and distribution costs.

Plant Rates

The rates included for the use of plant on a project are based on external charge-out rates. These rates are based on plant cost plus operating costs, depreciation, insurance, interest and internal overheads and are updated on an annual basis. Plant rates used were checked against Rawlinson's Australian Construction Handbook and found to be within the normally accepted range.

Overheads

Overhead costs associated with the installation of distribution network assets have been incorporated into the building block costs through the labour mark-up rates used in DQM.

Examples of overhead rates applied in other Australian network asset valuations gathered to provide guidance as to an appropriate level of overhead capitalisation are as follows:

Business	*2000 Western Power Valuation*	*SKM Precedents*	*Precedents in other DORC valuations*
Distribution	15%	10 – 18%	10 – 25%

The 2000 distribution valuation applied a general overhead capitalisation rate of 15% of total cost, including allowance to cover some general corporate overheads (such as costs incurred by the finance/administration function).

For the 2004 assessment, Western Power has examined the overheads absorbed through the DQM labour mark-up applied and found that the overhead absorption rate is insufficient to cover all overheads associated with a normalised level of capital works. Unfavourable variances have arisen consistently during 2003 through use of the standard labour mark up rate applied. The average mark-up rate of approximately $25 per hour within DQM was found to approximate only 10% of the MERA replacement cost. To fully recoup all relevant overheads, the rate applied within DQM would need to be uplifted to approximately $35 per hour. Application of this higher absorption rate increases the effective overhead within the MERA cost to approximately 15%.

The overhead rates applied to other utilities' ODRC valuations have ranged considerably between 10% and 25% depending on the methodology used. The factors which have influenced the overhead rates have included the assumed size of the replacement project, the complexity of replacement project and whether the utility was involved in the gas, water or electricity industries.

Western Power has chosen to adopt a level of overhead capitalisation on distribution assets at approximately $35 per hour which reflects an approximate capitalisation rate of 15%. This broadly represents the mid-point of the range adopted by other utilities and that noted by SKM (after adjustment for an additional contract management allowance). The rate is also similar to that adopted in 2000.

This assessment does not attempt to reconcile the treatment adopted by Western Power for financial accounting purposes with that adopted in the assessment of the RAB.

4.2.2 Transmission

The building blocks have been developed using parameters for the key cost inputs of core components and project based contract rates using Western Power, SKM and industry experience for such projects. Reference has also been made to the NSW Treasury Guidelines.

For overhead transmission lines, SKM provided unit base rates for high voltage lines and Western Power provided costs for recently completed or soon to be constructed 132kV lines that were used as part of the benchmarking process for overhead transmission lines. This data was particularly useful in establishing adjustment factors for foundations for lattice steel structures and poles in the coastal plains and for wind loading in cyclonic regions. For substations, Western Power relied on a detailed estimating package with some input from recent or current projects.

SKM has databases for transmission substations and overhead transmission lines that were used as part of the benchmarking process. These databases have been developed over a number of years. They are updated regularly using data obtained through various network asset valuation assignments and design/construct projects.

4.2.3 Interest During Construction

Distribution Assets

Interest during construction has not been applied to asset costs for distribution work due to the relatively short time frame of the construction activity for these assets. There is a lag of approximately four months between expenditure being incurred on distribution assets and this expenditure being updated in DFIS and the assets becoming operational. Separate adjustment has been made within the valuation assessment for expenditure on assets which has not been included in the DFIS operational equipment register at 31 December 2003 (from which the physical quantum of distribution assets to be valued has been derived). This adjustment removes the necessity to make allowance for interest during construction on distribution assets.

Transmission Assets

The construction timeframe for transmission asset projects is much longer than for distribution assets. The average construction timeframes for line and substation projects have been estimated to be approximately 18 months and 12 months respectively. To determine an allowance for interest during construction on transmission assets, expenditure profiles have been developed for typical 18 month line projects and 12 month substation projects. A nominal pre-tax WACC of 9.4% (reflecting a representative WACC for Western Power) has been applied to the expenditure profile to calculate an implied mark up for interest during construction. The resultant adjustment factors for these typical projects are as follows:

Duration of Project	***Factor***
12 months	5.5%
18 months	6.9%

4.2.4 Foreign Exchange Rates

The principal exposures to foreign currency within the Network assets are to the US dollar and the Euro. The cost of imported steel for lines is influenced by the exchange rate of the Australian dollar against Asian currencies which are linked to the US dollar. A number of core substation components are sourced from Euro denominated suppliers.

An exchange rate of 0.75 US dollars to one Australian dollar has been adopted for the purposes of this assessment, being the rate applicable as at 31 December 2003. The US dollar exchange rate has experienced considerable volatility over recent years. The rate at 31 December 2003 is relatively representative of the average exchange rate over the six months to 30 April 2004, but is considerably higher than has been experienced for the previous three years. The exchange rate approximated 0.70 US dollars to one Australian dollar as at 30 June 2004. Whilst, no change has been made to our assessment to reflect exchange rate movements since 31 December 2003, it is to be noted that a lower exchange rate will serve to increase the replacement cost of components purchased in US dollars.

4.3 Asset Lives

The economic lives of network assets are fairly uniform over the industry. Asset lives adopted are set out at Appendix B-1 (distribution) and Appendix C-1 (transmission). The lives applied are generally within the normal range of economic lives adopted by other Australian utilities. Deviations from the norm and changes from the previous valuation in 2000 are discussed below:

- ***Transmission substation equipment*** - the expected lives of transmission substation equipment have been increased from 40 years to 50 years. This is based on a reassessment of the expected lives and is consistent with trends in other jurisdictions.

- ***Transmission overhead lines*** **–** the economic life of lattice towers and tubular steel poles has been extended from 50 years to 60 years reflecting the condition and performance of these structures in the Western Australian environment. This is consistent with trends in other jurisdictions.

- ***Distribution overhead lines on wood poles*** - average asset lives for wood poles in the distribution network have been re-assessed and increased from 35 years used in the 1997 valuation to 40 years in the 2000 assessment. This has been further increased to 41 years in the current assessment. The increase in distribution line lives is based on the premise that wood poles that have been reinforced by the installation of steel reinforcement at the ground line will have an increase in life of approximately 15 years from the industry standard of 35 years for wood poles which have not been reinforced. Survey data on the extent of pole reinforcing has improved since 2000 and indicates that approximately 40% of all wood distribution line poles have been reinforced by this method. On a pro-rata basis, this higher percentage of reinforced poles reflects a weighted average increase in service life of lines of 6.0 years. The process of reinforcing poles is ongoing, albeit at a slower rate than historically, therefore it can be expected that the proportion of reinforced poles, and the average life of overhead lines, will increase marginally in the future before stabilising.

Western Power has a significant number of meters in service well beyond the current designated economic life of 25 years. Consideration was given to increasing the life of customer meters within the distribution networks from 25 years to 30 years. However, in the time available, Western Power was not able to compile meter accuracy test data for meters with an age in excess of 25 years. In order to adopt an extended age, such information would be necessary to demonstrate that there is no significantly diminished performance of meters within the extended age range. It is noted that whilst the industry standard life currently remains 25 years, at least one other Australian utility is challenging this standard in favour of a longer effective life. Accordingly, it is anticipated that the economic life for these assets may be reassessed in the future.

Consideration was also given to a possible change of economic life applicable to transmission lines on wood poles. Approximately 90% of the transmission wood poles are estimated to have been reinforced. This programme was initially implemented on a line section by section basis as found necessary, but subsequently by blanket reinforcement in an area and more recently as required based on regular condition monitoring and interim chemical treatment.

The Western Power records relating to this work on the transmission assets have improved since 2000 as a consequence of a full pole inspection programme. Improved records resulting from the pole inspections show a total of 3,013 poles older than 40 years, of which 82.2% have been reinforced. Of these, 1,916 are older than 45 years and 81.7% have been reinforced.

The economic life of 45 years for transmission wood poles has been retained for this assessment. It is anticipated that this will apply so long as the current inspection, chemical treatment and reinforcement routine is maintained.

The impact of the undergrounding program on the average age of the remaining overhead lines is difficult to determine with accuracy, but it is conceivable that it could accelerate the increase in the average remaining economic life of overhead lines (i.e. as older sections of overhead lines are removed from service the average age of lines should decrease.)

4.4 Assessed Ages of Assets

The ages of distribution plant and equipment have, in general, not been comprehensively documented and as a result the ages of a considerable portion of the distribution assets have been assessed. Records exist for transformers and tariff meters.

The ages for distribution lines and associated switchgear have been estimated in accordance with the valuation methodology set out at Appendix A. The average age of a distribution feeder is estimated on the basis of:

- either average meter age plus four years; or
- age assessed in 2000 evaluation plus four years; or
- by manual assessment where feeders have been put underground and the date of installation is known.

The ageing methodology was reviewed in 2000 and has been reassessed for the current valuation. The methodology is considered to provide a realistic estimation of the age of the distribution feeders. The model has been refined by using a default meter age of 50 years where meter age is unknown. The formula for this is attached in Appendix B-3. The formula recognises the rejuvenating effect which occurs from significant component replacement within individual feeders and weights the asset life extension relative to the proportion of capital replacement made within the feeder.

For the transmission network complete and accurate records of plant and equipment were available at the MERA level. In the case of substation circuit breaker bays, ages of the major plant and equipment were available at the sub-MERA level (such as circuit breakers and instrument transformers).

The age of substation bays is generally taken from the age of the circuit breaker. Where circuit breakers have been replaced, a weighted remaining life for the substation was calculated from the ages of all sub-MERA equipment. The respective weightings ascribed in sub-MERA equipment is shown in Appendix C-3.

Remaining Asset Lives

A minimum residual life of five years has been applied to all assets except:

- where there is a recognised schedule for removing plant and equipment which results in a future life of less than five years, ie removal of overhead lines as part of the State Government's directive to put distribution lines underground; and

- for meters, where a shorter residual life of three years has been adopted to reflect the extensive meter replacement program which is being planned and the generally shorter life of these assets relative to other network assets.

4.5 Optimisation

4.5.1 Technical Optimisation

The principles underlying the optimisation applied are set out in Section 2.16 of Appendix A. The purpose of optimisation is to identify instances of installed over-capacity, sub optimal network configuration and technical obsolescence.

Distribution Networks

Details of the general optimisations and the treatment adopted in the current distribution valuation are set out below.

Distribution Transformer Utilisation

The overall utilisation of distribution transformers is measured from the ratio of the system peak load in MVA (reduced by the estimated industrial load to allow for non-Western Power installed transformer capacity) and the total installed Western Power owned transformer capacity in MVA.

The typical power supply industry figures are 50% for urban distribution and 30% for rural distribution networks. The utilisation figures for the SWIN are 54% in summer and 45% in winter.

The Western Power transformer utilisation compares favourably with published data for other supply authorities. A review of distribution transformer ratings on individual zone substation feeders was undertaken to identify if there were any specific feeders which could be optimised.

A review of individual zone substation distribution transformer utilisation showed 23 to be under 40%, which is considered to be below the norm. A review of these feeders showed that individual rural consumers are equipped with over-sized transformers for their needs.

From a technical viewpoint, a 5kVA transformer would be adequate for individual rural consumers, however manufacturers have rationalised production and the smallest unit currently being manufactured is a 10kVA transformer.

After considering the rationalisation of installed transformer capacity and future system maximum demands over a five year planning horizon, it has been shown that 16 feeders had an excess transformer capacity. This has been optimised out of the valuation. Appendix B-4 includes an analysis of the results of this review.

Distribution Switchgear Utilisation

The 2000 valuation identified an excess of pole top isolators on the system and optimised the quantity of these within the 2000 valuation. This issue has been reviewed again for the purposes of this assessment.

The review has shown that pole top isolators are provided for each 1.75 kilometres of high voltage line and that they control on average 4.1 transformers. This is considered reasonable to provide the level of flexibility required to meet reliability targets.

The pole top isolators have therefore not been optimised in the 2004 valuation.

Low Voltage System

The low voltage network provides little scope for optimisation. Low voltage mains are designed against voltage drop considerations for the After Diversity Maximum Demand (ADMD) nominated. The range of conductors has been selected during the design phase for economic reasons which results in little scope for building in over-capacity. Similarly, services and meters are standardised against tariff classes and provide no scope for optimisation.

In the opinion of SKM, the ADMD planning criteria used for the design of the distribution network would yield high utilisation figures and some degree of overloading of the plant with little scope for optimisation. The load figures applied in this assessment are:

Residential Load Categories	*kVA Per Gas Dwelling Unit*	*kVA Per Non-Gas Dwelling Unit*
Single Dwelling Lots	3.0	3.5
Duplex, triplex, or quadruplex lots	3.0	3.5
Group Housing/Units up to 10 units	2.5	3.0
Denser Group Housing exceeding 10 units, Smaller Units and Retirement Villages	2.0	2.5

The planning horizon for distribution optimisation is five years. Annual load growths vary depending on the area but generally fall within the range of 3% to 10%.

The ADMD and planning horizons are similar to those used by other Australian utilities.

Conclusion
After a review of possible candidates for technical optimisation within the distribution networks, only technical optimisations for under utilisation of distribution transformers have been made.

The impact of the technical optimisations is to reduce the depreciated replacement value of transformer installations by $6.6 million.

Transmission Networks

Details of the general optimisations considered and the treatment adopted by us in the current valuation for these items are set out below:

- *Converting single 330kV circuits built as the only circuit on double circuit structures to single circuit structures where it was unlikely that the second circuit would be erected for 10 to 15 years.*
  Optimisations considered in this category previously resulted in some lines being optimised out of the asset valuation. All candidates for this optimisation considered under the current 2004 assessment were found to have planned use as double circuits within the planning horizon and accordingly no optimisation has been made.

- *Converting 132kV 1½ circuit breaker switch yards to single busbar except for major switch yards.*
  This optimisation was included in the 2000 assessment, but has been removed from the 2004 valuation. The optimisation was previously applied to substations at South Fremantle, Western Terminal and East Perth. These substations have a reliability criteria of N-2 under the transmission code and therefore the 1 ½ circuit breaker configuration is justified.

- *Replacing outdoor 22kV, 11kV and 6.6kV switch yards with indoor switch gear.*
  This optimisation was applied throughout the entire networks.

- *Transmission Transformer Optimisation*
  The optimal rating of a transformer is that rating which is adequate to support the maximum demand placed upon it. In addition, the reliability criteria that is applied to transmission transformers results in loading under normal network operating conditions well below their rating. Transformers are therefore rarely loaded at their maximum rated capacity.

  If a typical planning horizon of 15 years is adopted for the transmission network and an annual compounded load growth of 3% is assumed, then a transformer loaded to 65% of its force cooled rating will be loaded to 100% in 15 years. Most zone substations have two or more similarly rated transformers, the intention being that with one unit unavailable the remaining unit(s) can carry maximum demand.

  Where only one transformer is installed, and it becomes unavailable, the only resource is the surrounding network. Provided the adjacent substation transformers have capacity and the interconnecting lower voltage lines can carry additional load then the loss of the lone transformer is acceptable. Also the installation of a single transformer at substations with small maximum demands (say less than 10MVA) is also common practice.

  Ideally transformer optimisation could be seen to include adjacent feeder and transformer spare capacity but this would be a very lengthy process applied to the whole network. For the purposes of this valuation, a test was applied to identify those instances where maximum demand was equal to or less than 65% of firm capacity.

  For the transformers identified in this test, the circumstances of the particular substation were reviewed to decide whether optimisation was warranted. Optimisation would then be achieved by adjusting the asset value:

  - by removing one transformer if the remaining unit(s) could sustain maximum demand; and

- by allowing a transformer of lower rating where such a unit would be available at an economic price. This would usually mean that it is a commonly used size in the Western Power network.

Such optimisation is rendered more realistic by the availability of a Rapid Response Transformer (RRT) to cover serious breakdown, but it is available only for substations on the 132kV system and generally only in the Perth metropolitan area.

The table below shows the transformers which are candidates for optimisation, their 2003 maximum loadings as a proportion of firm capacity, recommended optimisations and comments where appropriate.

The data from which the table was compiled is contained in *"Transmission Load and Circuit Report" (Summer) NBU20-2003 (Winter) NBU60-2003*

Substation	***Voltage***	***Installed Capacity MVA***	***Max Demand MVA***	***% Demand***	***Proposed Optimisation***	***Comments***
Beenup	132/22	20/27	6.58	24	Optimise to 10/13MVA	
Boddington	132/22	20/27	1.6	6	nil	Standby supply to Alcoa
Kojonup	132/22	20/27	2.2	8.1	Optimise to 10/13 MVA	
Kondinin	220/33	45	8	18	Optimise to 27MVA	Min size for 220kV
Wagerup	132/22	2 x 20/27	14	26	No action	Required for wheeling
Yornup	66/22	3 x 5	3.9	26	Optimise to 2 x 5 MVA	
Forrestfield	132/22	20/27	8	30	No action	New industrial area. 50% load growth pa
Morley	132/22	1 x 95/144 1 x 20/27	39.2	23	Optimise larger unit to 20/27 MVA	
Southern Cross	66/33	2 x 10/12	0	0	Optimise out both transformers and switchgear	Alternate supply from Yilgarn 33kv
Wellington Street	132/22	2 x 20/27	24	45	No action	Back-up to CBD.
Nedlands	66/6.6	3 x 10/15	21.8	50.6	No action	Supported by the n-1 criteria

Below Voltage Transmission Line Optimisation

Optimisation candidates for lines operating at lower than design voltages are shown in the table below, together with the optimisation outcome adopted for the current review.

End 1	End 2	End 3	Line Circuit Ref	Operating voltage (kV)	Construction voltage (kV)	Optimise down?	Comment
Lines with different operating voltage from their construction voltage							
KW	ST		82	132	330	N	Due to proposed generation, this line is to be converted to 330 kV in 2009
KW	BP		72	66	132	Y	
CT	TT		71	66	132	Y	
CT	VP		71	66	132	Y	
CT	COL		71	66	132	Y	
PIC	CAP	WSD	71	66	132	N	Load growth in Busselton & Margaret River regions are expected to increase rapidly in the next 10 years: PIC-CAP-BSN-MR is to be converted to 132 kV
OC	SF		71	66	132	N	O'Connor substation to be converted to 132 kV within the next 15 years
OC	SF		72	66	132	N	
MOR	WGH		61	33	132	N	To be converted to 132 kV in 2015 for supply reliability.
GTN	CPN		61	33	132	N	It will be converted to 132 once the second 132/11 kV transformer is installed at CPN about 2015
NT	PJR		81	132	330	Y	
NT	PJR		82	132	330	Y	
KAT	WAG		71	66	132	Y	There are no plans to convert to 132kV within 20 years. Load growth in this area could require conversion to 132kV in the 25-30 year horizon.
NGS	WAG	NGN	71	66	132	Y	
DMP	DMS		61	33	132	N	Option to convert lines to 132 kV in the next 10 years to improve NWIS dynamic performance
DMP	DMS		62	33	132	N	
Double circuit lines with single side used							
KW	NT		91	330	330	N	New 330 kV terminal in 2015
NT	ST		91	330	330	N	New generation in 2012
MU	ST	KEM	91	330	330	N	New generation in 2007, 2009 and 2019
SHO	ST		91	330	330	N	New generation in 2019
Lines with over-capacity							
CLB	HDT		X1	220	220	N	220 kV is required for adequate dynamic system power transfer.

Capacitor Banks Optimisation

A program of installing capacitor banks in the Perth metropolitan area, principally for voltage support in the event of loss of a transmission line, was instituted following studies of reactive power control in 1996.

System Planning Branch Study Record SR537 "Reactive Power Requirements Review (2000-2003)" indicates that insufficient reactive power margin will be maintained for several system abnormalities and that further capacitive support will be required. The report states that load shedding will be required in double contingency situations. Recent studies indicate that reactive margins remain tight, and hence no optimisation is proposed.

Specific Transmission Optimisations

Muja – Merredin – Kalgoorlie

The Muja – Merredin – Kalgoorlie line (referred to as the Kalgoorlie line) was considered both for technical optimisation and economic optimisation. Due to the under-utilisation of the line's capacity it was considered for technical optimisation and due to its proximity to an alternative generation source, economic optimisation was also possible.

The existence of the alternative generation source made it feasible for the line to be replaced by gas turbine generation in Kalgoorlie which could supply customers from that location rather than having energy delivered from Muja using the existing transmission line. The outcome of the technical optimisation is discussed below and the economic optimisation review is separately considered in Section 4.5.2.

Kalgoorlie Line Utilisation

The Kalgoorlie line is constructed for 220kV operation and was carrying in the order of 170MW (the maximum effective line loading) at peak prior to construction of the Goldfields gas pipeline. In 2000, the load had fallen to approximately 70MW at peak, while privately-owned generation from Kalgoorlie supplied the balance under normal conditions. In 2004, the peak load recorded has been 100MW.

With the availability of gas for local generation, this line is a candidate for economic optimisation since under normal conditions the line only supplies approximately 40% (70MW/170MW) of its capacity load, although more recently a peak load of approximately 59% has been recorded. It was determined that although the line only supplies this load, in normal situations it also plays a critical role in security of supply for which the full 220KV capacity of the line is required. In addition, the recent peak load of 100MW is beyond the capability of a 132kV circuit of this length. For these reasons, it was decided that the line would not be technically optimised.

Cape Lambert – Port Hedland

This line is constructed for 220kV operation but with installation of a natural gas pipeline and two privately owned power stations at Port Hedland, demand on the line has fallen to about 25MW.

Redbank Power Station, which was owned and operated by Western Power, has been decommissioned but adequate spare capacity is available from the private generators to supply all loads in Port Hedland and, with notice, the Western Power loads in Roebourne and Karratha. The latter requirement would arise from a shortfall in generation at Cape Lambert beyond the nominal 10MW which Hamersley Iron could contribute.

The transfers which the 220kV line may be required to carry therefore are:

Normally	25MW	Cape Lambert to Port Hedland
Abnormally	20MW	Port Hedland to Cape Lambert
or	30MW	without Hamersley Iron input

Over a distance of 200 kilometres, these transfers are within the capacity of a 132 kV line. In the 2000 valuation, the line was optimised to 132kV. Recent system dynamic studies carried out by SKM and Western Power confirm that the 220kV operation is necessary for system stability between the power stations at Port Hedland, Cape Lambert and Dampier as well as proposed additional generation at Paraburdoo. The line has now been restored to 220kV in the 2004 valuation.

Yerbillon to Southern Cross 66kv Line

The 66kV line supplying Southern Cross (SX) has been made redundant by supply from Yilgarn at 33kV which is sourced from the 220kV line from Muja. The SX load size does not justify an n-1 level of redundancy and hence the 66kV sourced supply is optimised out. This includes two 10/12 MVA transformers, associated 66kv and 33kV switchgear and the 66kV line section.

4.5.2 Economic Optimisation

Distribution Networks

The economic optimisation evaluation model used in the 1995 and 2000 distribution asset valuation has been rolled forward by the distribution business for use in determining network prices. PwC and SKM have reviewed the distribution business' economic optimisation model and its subsequent roll-forward to ensure that the calculations correctly reflect valuation principles and are supported by reasonable assumptions. In addition, optimisation at a feeder level has been included at a greater level of detail in the current assessment.

Description of Optimisation Model

The model calculates an average cost of supply (in cents/kWh) to customers connected to each of the 19 zone substations that Western Power has determined may be subject to economic optimisation. The model also calculates the cost of supply for individual feeders emanating from these substations. In 1997, these zone substations were selected on the basis that a significant proportion of their customers were relatively remote from the zone substation thus the length of line supplying these customers was relatively long. SKM has no reason to believe that this situation has changed and therefore has agreed that the review of these 19 zone substations is still relevant.

The average cost of Western Power network supply is compared to an average long run cost of alternative energy supply, including localised small diesel engines, photovoltaic and wind generation. The comparison is made as a cents/kWh cost of supply basis which is the most reasonable basis for comparison. There are obvious differences in the load and number of customers for network versus localised supply and varying economic lives involved in the network assets, therefore the Equivalent Annuity Cost basis could not be used.

Consideration was also given to generating electricity using LPG (propane gas) fuelled engines in combination with photovoltaic and wind generation. Compressed natural gas (CNG) is not currently available outside of the metropolitan area for small scale generation. Accordingly, CNG has not been considered a viable alternative fuel source for remote generation at this time.

The Western Power distribution model averages the network supply over all customers connected to the zone substation in question, including rural properties and township customers. In reality, the cost of supplying a township customer is likely to be significantly less than a rural property customer simply because less assets are required to supply customers in a township - they are shared assets serving higher densities rather than, in some cases, lengths of line serving one or two customers only. The average figure is a broad assumption but it is difficult to arrive at a more detailed analysis given the level of information available. However, SKM has been advised that more than 90% of customers connected to the zone substations under review are on rural properties rather than in townships. Therefore, the average figure strongly reflects the cost of supplying a rural customer rather than township customers.

Review of Model

PwC retained the use of this averaging model to provide a preliminary review of regions which may be subject to economic optimisation with the intention of performing more detailed analysis on those regions which indicated potential optimisation issues as a result of this review.

SKM reviewed the assumptions, asset values and unit costs used in the model and found them to be reasonable. In addition, PwC/SKM have considered other alternatives to diesel power namely photovoltaic and wind generation as feasible supply options for remote locations. The Western Power distribution model includes the following costs:

- optimised replacement cost of the distribution network assets connecting all customers from each zone substation (excluding the cost of the zone substation) using the most recent values from this 2004 valuation;

- O&M costs for all distribution assets from each zone substation using the 2003/2004 budget Triennial review figures;

- total system share of administrative costs (less than 1 cent/kWh) using the 2003/2004 budget Triennial review figures; and

- pre-tax real discount rate of 7.2% (consistent with Western Power's current discount rate).

The results below are based on the cost of supply including energy and transmission supply costs.

Results by zone substation - inclusion of energy and transmission costs @ 7.87 cents/kWh

Region	***¢/kWh***
Moora	26.2
Katanning	24.7
Kondinin	36.6
Three Springs	27.8
Cunderdin	21.7
Muchea	16.1
Wagin	23.0
Eneabba	10.0
Merredin	20.6
Narrogin	20.6
Kellerberrin	25.9
Yornup	22.4
Wundowie	14.0
Quinninup	26.9
Yilgarn	9.1
Carrabin	14.6
Southern Cross	22.6
Kojonup	23.8
Margaret River	15.1

4.5.3 Average Cost of Alternative Supply

The determination of alternative supply costs for the 2000 review was largely based on a report dated October 1999 released by Murdoch University entitled '*Consultancy for the Alternative Energy Development Board to Evaluate the Size of the Off Grid Renewable Energy Market in Western Australia*'. The fuel and equipment costs for alternative supply options have been reviewed for the 2004 assessment.

BP have advised that the wholesale price of distillate ex Perth terminal was 87.15¢/l in the second quarter of 2000 and 83.85¢/l in the fourth quarter of 2003. This indicates a general 3.8% reduction in distillate prices since the 2000 review. However, in the intervening period the price ranged from 77.9¢/l to 92.47¢/l.

A report by the Sustainable Energy Development Office of the Government of Western Australia titled 'Opportunities for Renewable Energy Power Systems in Off Grid Areas of Western Australia under the Renewable Remote Power Generation Program' indicates that in mid 2003 the terminal gate prices in port towns in WA ranged from 83¢/l to 85¢/l and the retail cost of diesel in these towns was 5 to 10¢/l above the gate prices. For small towns, the price of diesel was from 90¢/l to $1.10¢/l and for a very remote pastoral station diesel can cost up to $1.50¢/l. The report also indicates that although household and pastoral stations can claim a 38.14¢/l rebate on diesel fuel excise, generally it is not claimed.

Accordingly, although the terminal gate prices have remained comparable to those at 2000, the prices in small towns have increased to $1.10¢/l and $1.50¢/l in very remote pastoral stations.

The consumers subject to the optimisation evaluation are remote small towns, households and pastoral stations. Accordingly, the previously Murdoch University alternative cost of supply study has been updated using a diesel cost of $1.10¢/l including excise and $0.72¢/l excluding excise. The updated alternative supply costs including capital costs are presented below.

Size of Load		*Diesel cost price*	*Diesel Only*	*Wind/Diesel System*	*Solar/Diesel System*
Household	- with excise	$1.10	$1.66/kWh	$0.90/kWh	$0.85/kWh
	- without excise	$0.72	$1.35/kWh	$0.78/kWh	$0.76/kWh
Small Community	- with excise	$1.10	$0.82/kWh	$0.67/kWh	$0.68/kWh
	- without excise	$0.72	$0.72/kWh	$0.51/kWh	$0.54/kWh

No adjustment has been made to the capital cost component of the costs as:

- the cost of diesel engines of the applicable size and type has not increased since June 2000;
- the costs of wind generators of the applicable size range have only increased approximately 8% since June 2000. This increase would have an insignificant effect on the net present cost of generation in $/kWh; and
- the costs of installations of photo voltaic generator plant in the applicable size range have been static since June 2000.

The cost of LPG fuelled engine generation has also been considered. The international prices of LPG have fallen from $467/tonne to $429/tonne since the 2000 review, a reduction of 8%. Prices quoted by a supplier in February 2004 in Carnarvon were $1.82/kg and $2.26/kg in Gasgoyne Junction. This compares with $1.50/kg for areas near transport and $2.00/kg for remote communities quoted in the 2000 report. These prices represent a 21% and 13% increase respectively from those adopted in 2000.

The cost of suitable LPG engines has remained static.

In the 2000 report, the costs of generation by LPG with and without wind or photovoltaic generation was found to be more than 19% higher than the diesel fuelled alternatives. Even if the 8% reduction in price in the international market for LPG were applicable, the diesel alternative remains the cheaper option.

Including the energy and transmission cost of supply and adopting a discount rate of 7.2% pre-tax real for Western Power, the zone substation with the highest cost of supply was Kondinin at 36.6 cents/kWh, followed by Three Springs with 27.8 cents/kWh. Specific cost modelling of the feeders from the candidate zone substations was then compared with 51 cents/kWh as the alternate cost of supply. This is the lowest alternate supply rate and corresponds to “diesel/wind – small community”. Nine feeders were identified with cost of supply greater than 51 cents/kWh.

However, use of 51 cents/kWh is not the most appropriate rate for the final analysis as these feeders are a mixture of towns and farm supplies. The alternate cost of supply “diesel/wind – household” is 78 cents/kWh.

Transformer sizes and installed kVA have been utilised to classify the proportion of load on each feeder into household or community and then determine a weighted average alternate cost of supply (510kVA transformers are assumed household, all others are community). A feeder with mainly households was tested against an alternate cost of supply around 78 cents/kWh whilst a feeder comprising mainly communities was tested against an alternate cost of supply around 51 cents/kWh with other combinations using a weighted average cost. This approach yields the following:

Feeder	Cost of Supply (cents/kWh)	Weighted Average Alternate Cost of Supply (cents/kWh)	DORC Adjustment ($’000)
ENB 602.0 North Mine	62.8	52	($139)
KAT 505.0 Kojonup	58.9	73	$0
KAT 512.0 Nyabing	53.5	62	$0
KEL 502.0 Shackleton	57.0	69	$0
KEL 5050.0 Trayning	52.5	67	$0
KOJ 504.0 Muradup	54.0	74	$0
KOJ 505.0 Jingalup	51.9	75	$0
SX 602.0 Moorine Rock	63.2	59	($439)
SX 609.0 Bullfinch	82.8	61	($1,085)

Three feeders have a cost of supply that exceeds the weighted average alternate costs of supply.

When Western Power originally constructed the ENB 602.0 North Mine and SX 609.0 Bullfinch feeders there were large mining loads to be supplied. These mining loads either no longer exist or have been significantly reduced. To make these lines economic requires a DORC reduction of $1.2 million.

Western Power originally constructed the SX 602.0 Moorine Rock line as a result of then government policy to promote rural electrification. A further DORC reduction of $0.4 million is required.

In summary, a reduction of $1.6 million has been applied to the SWIN DORC as a consequence of economic optimisation of the ENB 602.0 North Mine, SX 609.0 Bullfinch and SX 602.0 Moorine Rock feeders.

Transmission Networks

A review of the transmission network for economic optimisation was conducted to ensure consistency with the definition of ODV in Western Power's Transmission Access Arrangement. The definition of ODV is, according to the access arrangement, the lower of ODRC and ERV - or the value after economic optimisation (refer to Section 1.3 of Appendix A for further explanation of these principles).

The current access arrangement requires that a review for economic optimisation be undertaken to ensure that customers are only paying for the lowest cost supply of energy, among all feasible alternatives available.

To undertake this review the following process was conducted:

- review of assets subject to economic optimisation in the previous valuation; and
- a general review of the transmission network for potential economic optimisation.

These review processes are considered below.

Muja – Merredin – Kalgoorlie

Details of the Muja – Merredin – Kalgoorlie line capacity and utilisation are discussed above under technical optimisation. Although the line was determined to be critical for security of supply to the Kalgoorlie region, this region's proximity to the Goldfields gas pipeline (constructed after the Western Power transmission line) has created the potential for the line to be replaced with gas fired generation at Kalgoorlie which could then supply the surrounding towns without the existence of the current transmission line.

Using the definition of ODV in Western Power's Transmission Access Arrangement, the value represented in the asset base must equate to the option which delivers the lowest "whole of life" cost from:

- the feasible alternative (the ERV); or
- the existing asset (on a MERA basis, after technical optimisation).

The "whole of life" cost includes both the installation, maintenance and operation costs of the asset – refer Section 2.15 of Appendix A for a further discussion of this principle.

Estimated Replacement Cost of the Alternative Supply

Based on the discussions above, local generation would be required to have firm capacity of 215MW to service peak demand. The existing capacities (Summer ratings) of the existing Kalgoorlie generation are:

IPP1 – 2x LM6000	=	70
IPPS – 3x LM6000	=	105
WMC Smelter – steam sets	=	15
Western Power – Frame 6	=	31
Western Power – Frame 5	=	16
		237MW

This configuration results in a firm capacity (TIC –2) of 167MW if two of the largest sets are unavailable. To meet peak demand a further 48MW of generation capacity is required. This may be met by an additional two LM6000 units. Some additional assets are also required to provide acceptable standby from the configuration.

The overall installation and operating cost (in net present value terms) of this substitution on an EAC basis was $54.9 million. This cost estimate includes the additional generators, supply of gas plus:

- a 132kV line from Muja to Yilgarn to pick up existing consumers at Bounty and Yilgarn, maintain supplies to Kojonup, Narrogin, Wagin and Katanning and provide an alternative supply to Merredin which is otherwise dependent on a radial system from Perth via Northam; and
- replacement of the gas turbines after 25 years.

The annual equivalent operating cost of the replacement for the Kalgoorlie line 220kV system on an EAC basis was $56.6 million using a 50 year economic life of substations and 60 years for the transmission lines. After deducting operating and power costs of the existing line, the capital component of the annual equivalent cost of the Yilgarn to Kalgoorlie line would require to be scaled back by a factor of 90% or $22.8 million to have parity with the Kalgoorlie generation option.

The optimisation is sensitive to any differential movement in fuel prices between coal and gas. Should the cost of gas rise by less than 10% relative to coal, then no optimisation would arise.

A breakdown of the assessed costs in included in Appendix C-4.

Conclusion

There is a lower economic cost in providing generation capacity in Kalgoorlie compared to the cost of the Muja to Kalgoorlie line. Accordingly, optimisation has been applied to the substations and line sections making up this system. The optimisation applied has reduced the ORC by $22.8 million and the DORC by $15.1 million.

Cape Lambert – Port Hedland

The Cape Lambert to Port Hedland economic optimisation considers operating this system as two independent systems based around Karratha/Cape Lambert and around Port Hedland with no interconnecting line. Whilst the Karratha/Cape Lambert system has sufficient generation capacity to meet its needs, additional generation capacity is required at Port Hedland to meet supply reliability criteria.

No significant EAC differential arises from local generation alternatives. Accordingly, there does not appear to be a case for economic optimisation of this interconnector.

4.6 Other non-System Network Assets

4.6.1 Nature of non-System Network Assets

Non-system Network assets comprise those assets owned by and utilised in the transmission and distribution operations, but which do not form part of the physical plant and equipment network infrastructure. In particular, land and easements upon which infrastructure is built has been included within the classification of non-system assets, along with SCADA and communications equipment.

4.6.2 SCADA and Communications Equipment

SCADA and communications equipment has been assessed by reference to a building block approach to derive a depreciated replacement cost value as at 30 June 2004 of the equipment on hand as at 31 December 2003. The SCADA value determined on this basis does not include additional equipment being installed as part of an augmentation of a new transmission SCADA master station in progress at the date of this report.

SCADA and communications equipment has been included in the 2004 assessment on the basis of DORC in line with conventional regulatory principles. This represents a departure from the approach adopted in the 2000 valuation assessment where book value was the prescribed basis for assessment of all non-system assets.

4.6.3 Easements

Easements have been included at cost consistent with the approved methodology and regulatory practice. Not all expenditure on easements has been captured in the financial asset registers. Further, the amounts reflected in the financial asset registers have been subject to depreciation. For the purposes of our assessment, depreciation has been reversed and adjustments made for easement acquisitions identified as not being included in the financial asset register.

4.6.4 Property

The property assets associated with the Networks primarily consist of depots, offices and padmount transformer sites upon which infrastructure has been built. Also included within this category is regional housing associated with the Networks business.

For the purposes of the 2004 valuation assessment, the main common depot at Jandakot and the Head Office have been classed as shared services assets and are included in the separate assessment for Other Assets as at 30 June 2004.

Land holdings have been ascribed unimproved land values assessed by the Valuer General for land tax and rating purposes. The Valuer General assessments have been indexed from 30 June 2003 to 30 June 2004 at estimated CPI for this period.

Land that is held on a “vested” basis has been included in our assessed value of land. Vested land entitles Western Power to all the rights and benefits of ownership, with the only restrictions being the inability of Western Power to transfer the land or use it for purposes other than transmission or distribution. It is on this basis that we consider vested land to be more representative of actual land holdings than easements and as such it has been included in our assessed value of land.

Regional housing has been valued by reference to recent representative property transfer values for similar properties. With the exception of residential housing, buildings have been reflected at their 31 December 2003 book value and are not material to the Networks valuation assessments.

The Network property assets were included at book value for the purposes of the 2000 assessment, but consistent with current regulatory practice have been included at fair value for the purposes of the 2004 assessment.

4.6.5 Other non-System Assets

There is a range of other non-system assets reflected within the Networks financial asset registers. These assets principally comprise non-system plant and equipment, office equipment, test equipment and some capital spares. These assets have been reflected at their 31 December 2003 accounting book value. This amount has been taken as representative of market value as at 30 June 2004 with depreciation largely offsetting any value movement to 30 June 2004.

Many items of non-system plant and equipment are included within the financial asset registers under the general classification of plant and equipment. This classification also includes the system plant and equipment which has been separately assessed by way of the building block approach. The non-system equipment has been identified based upon its description in the fixed asset register. Whilst reasonable procedures have been adopted to identify such equipment, not all non-system equipment may have been identified through this process.

4.6.6 Summary of non-System Network Assets

The values of the non-system assets at 30 June 2004 which are not covered by the general plant and equipment building blocks together with a comparison to 2000 are summarised below.

Distribution Non-System Assets	***NBV 30 June 2000 $ million***	***NBV 31 December 2003 $ million***	***Assessed value 30 June 2004 $ million***	
South West Interconnected System				
Communications system including SCADA	2.6	2.1	9.4	(a)
Office equipment	3.3	3.0	3.0	
Land	3.2	2.6	16.9	(b) (f)
Buildings	25.2	17.0	17.3	
Plant and equipment	27.7	20.3	20.3	
Non-system assets	62.0	45.0	66.9	
North West Interconnected Network				
Office equipment including SCADA	0.1	0.1	0.1	(a)
Land and buildings	2.9	5.3	5.7	(b)
Plant and equipment	0.4	0.2	0.2	
Non-system assets	3.4	5.6	6.0	

Regional Isolated Networks				
Office equipment including SCADA	0.1	0.3	1.4	(a)
Land and buildings	2.1	3.5	6.8	(b) (f)
Non-system assets	2.2	3.8	8.2	
Total Distribution Non-System Assets	**67.6**	**54.4**	**81.1**	

Transmission Non-System Assets	***NBV 30 June 2000 $ million***	***NBV 31 December 2003 $ million***	***Assessed value 30 June 2004 $ million***	
South West Interconnected System				
SCADA and communication systems	31.8	19.4	31.3	(a)
Test equipment	2.1	1.4	1.4	
Office equipment	0.8	2.3	2.3	
Buildings	11.4	12.2	12.2	(d)
Spares	0.2	0.2	0.2	
Land	9.8	21.8	51.8	(b) (d) (f)
Easements	12.6	4.7	14.7	(c)
	68.7	62.0	113.9	
North West Interconnected System				
SCADA	2.4	0.4	0.5	(a)
Land, buildings and office equipment	2.5	1.9	3.1	(b) (e) (f)
	4.9	2.3	3.6	
Total Transmission Non-System Assets	**73.6**	**64.3**	**117.5**	

Notes specific to distribution and transmission non-system assets:

(a) *SCADA uplifted to DORC assessment from book value previously adopted;*

(b) *Change of basis from book value to unimproved land value;*

(c) *Inclusion of easements not reflected in financial asset register and reversal of the accumulated depreciation reflected in the financial asset register.*

(d) *The SW control centre is included within the SWIS assessed value for land and buildings $4.8 million.*

(e) *The NW control centre is included within the NWIS assessed value for land and buildings at $1.2 million.*

(f) *Assessed value of land includes vested land for SWIN of $9.2m, RIN of $0.5m, SWIS of $2.0m and NWIS of $0.6m.*

4.7 Summary of Network Asset Valuation

The foregoing text and associated appendices detail the unit values used in this valuation and the aggregation of overhead lines, underground cables, transformers, substations, meters and other system and non-network assets associated with the distribution and transmission networks.

The total values for the Networks are summarised in the following tables (in $ million).

While it is normal in asset valuations to provide a range of values, we have been requested to provide single point estimates of value. It should therefore be recognised that there is a feasible range of values for the distribution and transmission network assets, particularly given the significance of a number of the assumptions and estimations which have been made in the valuations and the variability of factors such as market conditions and prices.

Summary of Distribution Asset Valuations – 30 June 2004

	RC *$m*	*DRC* *$m*	*ORC* *$m*	*DORC* *$m*	*ODV* *$m*
South West Interconnected Network					
Lines and cables	2,187.4	1,178.9	2,187.4	1,178.9	1,177.3
Transformers	434.3	259.7	423.6	253.1	253.1
Switchgear	273.2	117.8	273.2	117.8	117.8
Meters	400.2	162.8	400.2	162.8	162.8
Streetlights	146.9	78.5	146.9	78.5	78.5
System assets to be recorded in operational register at December 2003		40.6		40.6	40.6
Estimated additions to 30 June 2004		66.2		66.2	66.2
Other non-system assets		66.9		66.9	66.9
Total South West Interconnected Network		1,971.4		1,964.8	1,963.2
North West Interconnected Network					
Lines and cables	37.4	22.8	37.4	22.8	22.8
Transformers	8.9	5.2	8.9	5.2	5.2
Other network assets (switchgear, meters, streetlights)	15.0	6.3	15.0	6.3	6.3
System assets to be recorded in operational register at December 2003		0.9		0.9	0.9
Estimated additions to 30 June 2004		1.4		1.4	1.4
Other non-system assets		6.0		6.0	6.0
Total North West Interconnected Network		42.6		42.6	42.6
Regional Isolated Networks					
Lines and cables	140.3	91.1	140.3	91.1	91.1
Transformers	22.3	13.9	22.3	13.9	13.9
Other network assets (switchgear, meters, streetlights)	26.5	12.5	26.5	12.5	12.5
System assets yet to be recorded in operational register at December 2004		2.2		2.2	2.2
Estimated additions to 30 June 2004		2.2		2.2	2.2
Other non-system assets		8.2		8.2	8.2
Total Regional Isolated Networks		130.1		130.1	130.1
Total Distribution Networks		2,144.1		2,137.5	2,135.9

Only $1.6 million of economic optimisation has been applied to the DORC assessment of the Distribution Networks. Accordingly the ODV and DORC values are substantially the same.

Summary of Transmission Asset Valuations – 30 June 2004

	RC *$m*	*DRC* *$m*	*ORC* *$m*	*DORC* *$m*	*ODV* *$m*
South West Interconnected System					
Substations	1,181.1	620.0	1,139.6	598.8	598.8
Substation land	51.8	51.8	51.8	51.8	51.8
Transmission lines	888.7	495.0	865.1	480.7	465.6
Easements	14.7	14.7	14.7	14.7	14.7
Underground cables	19.0	10.6	19.0	10.6	10.6
Tariff metering	2.9	2.0	2.9	2.0	2.0
SCADA and communications equipment	89.9	32.9	84.3	31.3	31.3
Other non-system assets		16.1		16.1	16.1
Total South West Interconnected System		1,243.1		1,206.0	1,190.9
North West Interconnected System					
Substations	86.7	43.5	81.8	41.6	41.6
Transmission lines	77.1	50.4	77.1	50.4	50.4
Other non-system assets		3.6		3.6	3.6
Total North West Interconnected System		97.5		95.6	95.6
Total Transmission Networks		1,340.6		1,301.6	1,286.5

Parts of the Eastern Goldfields transmission system within the South West Interconnected System are subject to joint ownership. For regulatory purposes, the full asset value is recognised within the regulatory ODV.

For accounting purposes, the carrying value of the relevant Eastern Goldfields assets should be reduced proportionate to the private ownership interest.

The privately owned portion of the Eastern Goldfields transmission system is as follows:

	RC *$ million*	*DRC* *$ million*	*ORC* *$ million*	*DORC* *$ million*	*ODV* *$ million*
Private Portion of Lines	22.6	14.8	22.6	14.8	10.8
Private Portion of Substations	18.3	10.3	18.3	10.3	10.3
Total private portion	40.9	25.1	40.9	25.1	21.1

Accordingly, for accounting purposes the DORC of the SWIS reduces to $1,180.9 million and the ODV of the SWIS reduces to $1,169.8 million.

4.8 Sensitivities

The preparation of the above valuations has involved extensive estimation of costs for MERA building blocks. The level of accuracy of individual MERA cost estimates varies depending on the regularity of such expenditure and supporting cost information. In particular, there is a reasonably high level of accuracy associated with assets such as underground distribution cables where extensive cost support is available and for building block costs which are primarily driven by regularly quoted components such as transformers. Other individual MERA assets such as some overhead lines may only have accuracy in the order of a ± 20% range in the absence of a formal tendering and quotation process. However, even within these more subjective assessments, as the number of individual MERA building blocks increases, the average level of accuracy in the mean MERA cost determination will improve within this range. The level of accuracy further improves when weighting the more subjective cost estimates with those which can be assessed with more certainty.

The overall average MERA cost range adopted for Network assets mostly accords to the mean which SKM considers appropriate.

However, in addition to cost estimates, there are a number of other core judgemental areas (most notably, the perceived economic asset life of each MERA) and significant estimates required where the quality of information is deficient (mainly the age of distribution feeders and to a much lesser extent, asset specification where not recorded). Generally where information has been deficient, a minimum capacity specification or higher average age has been adopted. Similarly, the assessment of economic lives for Network assets tends to have a conservative bias. These factors introduce a low valuation bias to the resultant assessment and adds further volatility to the valuation above that of cost estimation.

Accordingly on balance, we consider that the single point values presented above may be marginally below the mid point of the acceptable valuation range and has a level of accuracy within ±10%. We do not consider this level of accuracy to be unreasonable for a valuation of this nature.

5 COMPARISON WITH PREVIOUS VALUATIONS

5.1 Comparison of the Current and Previous Distribution Valuations

The previous distribution valuation was undertaken in 2000 using valuation principles applicable for the Western Power Distribution and Network Access Regime. A summary of ODV asset valuations as at 30 June 2004 and the previous assessments applied to determine the RAB is set out below.

	30 June 2004 $m	***30 June 2000 $m***
South West Interconnected Network		
Lines and cables	1,177.3	983.1
Transformers	253.1	247.2
Switchgear	117.8	85.4
Meters	162.8	152.4
Streetlights	78.5	55.1
System assets to be recorded in operational register at December 2003	40.6	-
Estimated additions to 30 June 2004	66.2	-
Other non-network assets	66.9	62.0
Total South West Interconnected Network	1,963.2	1,585.2
North West (Pilbara) Interconnected Network		
Lines and cables	22.8	20.2
Transformers	5.2	5.4
Other network assets (switchgear, meters, streetlights)	6.3	5.3
System assets to be recorded in operational register at December 2003	0.9	-
Estimated additions to 30 June 2004	1.4	-
Other non-network assets	6.0	3.4
Total North West Interconnected Network	42.6	34.3
Regional Isolated Networks		
Lines and cables	91.1	79.7
Transformers	13.9	12.2
Other network assets (switchgear, meters, streetlights)	12.5	11.6
System assets to be recorded in operational register at December 2003	2.2	-
Estimated additions to 30 June 2004	2.2	-
Other non-network assets	8.2	2.2
Total Regional Isolated Networks	130.1	105.7
Total Distribution Network Value	2,135.9	1,725.2

5.2 Brief Comments on Main Reasons for Changes in the Distribution Valuations from 2000

The key factors influencing the movement in distribution asset values are summarised as follows.

5.2.1 SWIN

Lines and Cables

- A 14% increase in value is attributable to changes in the physical asset base between June 2000 and December 2003. This relates to the addition of capacity, reclassification and replacement with underground (net of retirements).

- A net average increase in building block costs of approximately 4% (nominal) between June 2000 and June 2004. Whilst the overall increase is relatively small, some building block unit costs have moved more significantly between 2000 and 2004.

- A change in the assessed asset life of wood poles due to a higher proportion of wood poles being subject to steel reinforcement.

- Amortisation of the asset base over the intervening four years.

- Reassessment of feeder ages both through improved data on average meter age and improvements to the manner in which average age is calculated where not all meter ages in a feeder are known.

- Rejuvenation arising from the weighted impact of replacement expenditure on distribution network feeders.

Transformers

- A net decrease of 12% in value is attributable to changes in the asset base between June 2000 and December 2003. This relates to the improved accuracy in numbers recorded and physical characteristics as well as physical changes in the underlying asset base.

- A small decrease in average building block costs for transformers of 1.4% between June 2000 and June 2004.

- Amortisation of transformers over the intervening four years.

Switchgear

- The overall ODV of switchgear has increased between 2000 and 2004 primarily due to expansion of the physical assets base by 17% and a reduction in the impact of switchgear technical optimisation. Amortisation has largely been offset by asset age refinement and a 4% increase in the average building block costs applied.

Meters

- A refinement in the manner of determining average meter life has led to a reduction in the assessed average meter age by almost four years which effectively offsets the amortisation in the period from June 2000 to June 2004.

- A modest increase in meter numbers has largely been offset by a reduction in average replacement costs.

Streetlights

- The ODV of streetlights has increased substantially since June 2000 largely as a consequence of improvements to the MERA costing which corrected a number of minor errors in the previous valuation.

- Improvements to the methodology for application of age data has led to an increased average age for streetlights.

Work-in-Progress

- Work-in-progress has been included in the valuation for the first time in 2004.

Additions to 30 June 2004

- Additions since 31 December 2003 have been included to roll the valuation through to 30 June 2004.

Other Assets

- Other assets have been assessed by reference to conventional valuation principles for the 2004 assessment whereas book value was adopted in 2000:

    - SCADA and communications equipment has been uplifted by $8 million from 2000 largely as a consequence of new capital expenditure; and
    - Land has been uplifted by $13.7 million from 2000 largely as a consequence of adopting Valuer General valuations.

5.2.2 NWIN

- Similar to SWIN, the valuation movement between 2000 and 2004 represents minor changes in the physical assets, a modest increase in costs, some reassessment of asset ages, depreciation over the intervening period and an uplift in market land values.

5.2.3 RIN

- There has been an approximate 10% expansion of regional network assets with a corresponding movement in value. Improvements in MERA costing and asset aging within the RIN largely mirror those within the SWIN, but do not have a material impact on the RIN value other than for work-in-progress and an uplift in land values.

5.3 Conclusion on Comparison of Distribution Valuations

The 2004 distribution valuation assessment represents an uplift of 23.8% from the 2000 valuation. Approximately 50% of the net uplift in value arises from capital expenditure on the distribution network over this period exceeding depreciation. The remaining net uplift in value largely arises from modest increases in building block costs, a net reduction in average feeder and meter ages arising from better application of ageing calculations and from including capital work-in-progress.

After notionally including a comparable amount for capital work-in-progress for SWIN in 2000, the 2004 SWIN valuation reflects a 1% reduction in DORC/kVA and a 4% increase in DORC/connection both stated in 2004 dollars.

Western Power has undertaken extensive work to improve the quality of the data used in the valuation assessment and this is reflected in the nature of the modifications made to the underlying data since the 2000 assessment.

5.4 Comparison of the Current and Previous Transmission Valuations

	30 June 2004 $m	*30 June 2000 $m*
South West Interconnected System		
Substations	598.8	424.7
Substation land	51.8	9.8
Transmission lines	465.6	417.2
Easements	14.7	12.6
Underground cables	10.6	10.8
Tariff metering	2.0	2.0
SCADA and communication equipment	31.3	31.8
Other non-system assets	16.1	14.5
Total South West Interconnected System	1,190.9	923.4

	30 June 2004 $m	*30 June 2000 $m*
North West Interconnected System		
Substations	41.6	29.8
Transmission lines	50.4	38.9
Non-system assets	3.6	4.9
Total North West Interconnected System	95.6	73.6
Total Transmission Network Value	**1,286.5**	**997.0**

5.5 Brief Comment on Main Reasons for Changes in the Transmission Valuations from 2000

The key factors influencing the movement in transmission asset values are summarised as follows.

5.5.1 SWIS

Substations

- Four new substations and significant upgrades/refurbishment to more than 25 others within the SWIS.

- Depreciation over the intervening period largely offsetting the capital expenditure made.

- An average uplift in MERA building block rates of approximately 25% since the 2000 assessment. This is attributable to more extensive benchmarking data being available for the 2004 review which has supported a cost uplift in replacement cost benchmarks of 8% to 10% in real terms since 2000 (approximately 20% in nominal terms). In addition, the substation building blocks now represent a small premium (2.6% on a replacement cost basis and 1.3% on a DORC basis) to those adopted by SKM, but still remain within the tolerable level of estimating accuracy.

- Extension of asset lives for some substation equipment from 40 to 50 years with an estimated impact on DORC of between $50 million and $60 million.

- Minor adjustments to asset ages which have been based on order date plus one year in the current assessment (rather than commissioning date as was used in 2000) to avoid restarting asset life when equipment is moved between substations.

Substation Land

- Movement from a historical cost basis in 2000 to a Valuer General assessed unimproved land value as at 2004.

Transmission Lines

- Expenditure on new lines has exceeded depreciation.
- An increase in average line MERA costs of approximately 3% since 2000.
- Extension of asset life for lattice towers and tubular steel poles from 50 to 60 years adding an estimated $26 million to DORC.

SCADA and Communication Equipment

- This equipment has been restated from a book value basis in 2000 to a DORC basis in 2004.

Other Assets (Easements, Underground Cables, Tariff Metering and Other Non-System Assets)

- Movements in value have been in accordance with underlying physical movements in the asset base between 2000 and 2004.

5.5.2 NWIS

Substations

- There have been no significant changes to the underlying asset base.
- Unit costs have increased by approximately 27% since 2000 for similar reasons to those outlined for SWIS.
- Increasing the life of some substation equipment from 40 to 50 years has added approximately $4 million to the DORC.

Transmission Lines

- The removal of a line optimisation accounts for an increase of $4 million in the ODV of transmission lines in NWIS.
- The 2000 valuation erroneously excluded the appropriate allowances for wind loading. The correct application of unit cost multipliers resulted in an increase of approximately $7 million to the DORC.

5.6 Conclusion on Comparison of Transmission Valuations

The 2004 transmission ODV assessment represents an uplift of 29.0% from 2000. Capital expenditure has significantly exceeded depreciation. However, most of the capital expenditure above depreciation has not been recognised within the closing DORC balance as it relates to operational improvement or incremental expansion where full credit for the original asset cost plus augmentation cost is not reflected in the MERA asset cost base and there has been no corresponding increase in asset life.

The increase in DORC from 2000 is mostly attributable to changes in building block costs (particularly substations), reassessment of asset lives and restatement of transmission load to a valuation basis.

The overall SWIS DORC/GWh has increased by approximately 3% in real terms from the 2000 assessment and 1% after removing the impact of changing the valuation basis of land and SCADA.

6 DECOMMISSIONING PROVISIONS

6.1 Determination of decommissioning provisions

Based on discussions with Western Power, it is considered that there are unlikely to be material decommissioning obligations within the distribution or transmission networks for the following reasons:

- there are no known significant environmental cleanup issues on the current networks sites;
- the nature of the assets do not give rise to significant contamination or decommissioning obligations; and
- the ongoing use of the sites ensures any issues with sites are deferred thereby reducing the present value of any obligations which may exist. The substation sites are integral to the lines servicing an area and it is expected that upgrading and replacement of equipment will be under taken to provide a continuous service facility.

Accordingly no decommissioning liability has been identified for the networks businesses.

7 GENERAL

7.1 Limitations on Usage of Report

This report has been prepared at the request of the Electricity Reform Implementation Unit (ERIU) by PwC in conjunction with SKM for the purposes outlined in this report. This report is not intended to be utilised or relied upon for any other purpose. Accordingly, we accept no responsibility in any way whatsoever for the use of this report by any other persons or for any other purpose.

Appendix A Network Assets Valuation Methodology

1 GENERAL VALUATION PRINCIPLES

1.1 Overview

DORC or ODV is the prescribed valuation methodology for the majority of Western Power's generation and networks assets (ODV forms the basis for most of the networks' RAB assets). There is some subjectivity associated with the application of DORC and ODV methodologies. A number of alternative approaches are possible in relation to underlying principles and key issues. We have set out below the principles to be adopted in relation to key methodology issues.

The ODV of an asset is the lower of the DORC of the asset and the economic replacement value (ERV) of the asset, where:

- the DORC of the asset is the cost of meeting the current (and projected future) supply needs with the most technically efficient design and configuration of the asset based on the existing system configuration, depreciated based on the proportion of economic life remaining; and

- the ERV of an asset is the minimum cost of replacing the asset with a more economic alternative which still achieves the same result, depreciated based on the proportion of economic life remaining.

If the DORC of an asset is lower than the ERV of the asset, the DORC represents the ODV of the asset. In other words, if the system was deprived of the asset, it would be replaced with the technically optimum equivalent. However, if the DORC of an asset is greater than the ERV of the asset, then the ERV would represent the ODV of the asset because theoretically the asset would not be replaced in its current form, but rather the users would notionally replace it with the economically preferable alternative.

1.2 Depreciated Optimised Replacement Cost (DORC)

Conceptual Framework

The DORC is calculated based on the current replacement cost of modern equivalent replacement assets (MERA), that is adjusted for over-design, over-capacity and/or redundant assets, less an allowance for depreciation.

The DORC valuation approach is used to determine a hypothetical value of the assets by reference to the replacement cost of the industry assessed lowest cost alternative.

Where market evidence is readily available, it is possible to establish a relationship between market value and replacement cost. Where market evidence is available for the same broad asset at varying ages, it becomes possible to establish a loss in value or depreciation profile. By its very nature, such a profile takes into account supply/demand characteristics and the impact of all other factors on value.

Conversely, in the absence of suitable market data, the valuer seeks to construct a loss in value or depreciation profile by measuring by other means the various factors that impact on value.

In respect of the optimisation part of this measurement process, the valuer attempts to assess value by reference to the concept of substitution. It is logical to assume that the maximum amount a potential purchaser would be prepared to pay for an asset is represented by the purchaser’s lowest alternative cost to replicate the asset. In assessing what represents the lowest alternative cost, consideration must be given to the optimum set of assets that would be required to provide the reasonably foreseeable services required to be delivered by the assets.

The DORC of the electricity transmission and distribution assets has been described as representing the minimum cost of replacing or replicating the service potential embodied in the network with modern equivalent assets in the most efficient way possible from an engineering perspective, given the service requirements, the age and condition of the existing assets and replacement in the normal course of business.

This concept is consistent with the principles of fairness and equity required in assessing access charges in that users only pay for those assets that are required in a commercial context and therefore are not required to pay for any excess capacity or over-engineering embodied in the existing assets.

As outlined above, the DORC approach involves three main steps:

- establishing the MERA of the gross service potential embodied in the existing assets;
- adjusting the gross current replacement cost determined above for over-design, over-capacity and/or redundant assets; and
- depreciating this value to reflect the anticipated effective working life of the asset from new, the age of the asset and the estimated residual value at the end of the existing asset’s working life (refer Section 1.9).

Establishment of MERA Replacement Cost

The MERA replacement cost is determined by reference to the current market buying price, current reproduction cost or replacement cost of modern equivalent assets.

In respect of specialised assets such as most network infrastructure, the appropriate cost is the lower of the current replacement cost and the current reproduction cost of the gross service potential of the existing asset.

The MERA cost can be established:

- by comparison with recent costs of similar assets;
- by reference to historical costs, adjusted for inflationary increases since construction;
- by contacting suppliers, manufacturers or their agents; or
- by reference to recently published prices.

Modern Equivalent Replacement Asset

Guidance in determining replacement costs is provided in Statement of Accounting Practice SAP1 "Current Cost Accounting". SAP1 states that the replacement cost to be used is the "lowest cost per unit at which the gross service potential could be obtained in the normal course of business".

MERA cost is defined as:

> *"The minimum that it would cost, in the normal course of business, to replace the existing asset with a technologically modern equivalent new asset with the same service potential, allowing for any differences in the quantity and quality of output and in operating costs".*

The statement above requires the valuer to measure the gross service potential of an existing asset by reference to its modern equivalent asset. Reference to the modern equivalent asset is only made so as to obtain a current replacement cost for the asset already held, regardless of whether the modern equivalent asset will ever be purchased, or whether the existing assets will ever be replaced.
Further SAP 1, states:

> *"In determining current cost with reference to the most appropriate modern facility the capacity of that facility should not be such as would exceed materially…the scale of the entity's existing operations. The modern facility should be of commercially available technology and should not require a redesign or re-engineering of an entity's existing plant "*

Expected Capacity in Use

The replacement costs of individual assets should be based on the "expected capacity in use" of the existing assets. "Expected capacity in use" is the required level of service potential or output consistent with both the future growth in demand and the objective of minimising the whole of life cost of assets under "total asset management" concepts and business planning horizons. As systems expand and change, a degree of sub-optimality at any one time is inevitable and is part of the total cost of output.

Where the modern equivalent asset has a different capacity, a pro-rata adjustment is necessary to value the expected capacity in use of the existing asset. This determination of the modern equivalent asset that would replace existing individual components of the network should not be confused with the process of optimisation.

Cost Basis

Current costs can be determined on a "greenfields" or "brownfields" basis. The "greenfields" cost basis assumes construction occurs in an area free of development and that the most efficient network, given current usage, is established. The "brownfields" cost basis assumes construction occurs around all existing infrastructure and development (other than the asset being valued) and that the assets are fundamentally replaced in the same location. Accordingly, preliminary costs such as route planning for the distribution network are not included.

The "brownfields" cost basis is considered appropriate because it is consistent with the concept of establishing the potential purchaser's lowest alternative cost to replicate the network (ie a duplicate network would need to be built in the existing environment) in the ordinary course of business (as opposed to complete system re-design). The current cost estimates should reflect the current state of land use development.

The "brownfields" cost structure is widely used for DORC valuations including electricity, gas and water infrastructure assets in most States.

Market Values

Where there is an active market for the assets being valued, the fair value of the specific asset has been compared to the value that can be assessed from market information to ensure that there is no material difference.

1.3 Optimised Deprival Value

To enhance the applicability of ODV for Western Power's regulatory purposes, the definition of ERV in the Western Power access arrangements has been adopted for the purposes of this assessment:

> "*the minimum cost of replacing the asset with a more economic alternative which still achieves the same result*"[1]

This definition attempts to ensure that customers are only paying for the least cost alternative supply of energy.

The ERV test prescribed in the Western Power access arrangements differs from that applied in practice in other States' regulatory regimes. In New South Wales, Victoria and Queensland, the ODV methodology applies an economic value (EV) test to assets using the net present value of expected cashflows from the assets. However, there are circularity problems associated with using net present value calculations as a basis for setting asset values for pricing purposes. Accordingly, in practice the DORC methodology is the

[1] Western Power. *Electricity Transmission Access – Pricing and Charges, 1 July 1999 to 30 June 2000. ___ September 1999, pE3*

commonly applied approach in these jurisdictions with optimisation considered based on the "ordinary course of business" replacement. Further, as previously indicated, the cashflow modelling for the Successor Entities has not yet been completed. Our assessment of DORC has been undertaken in a manner consistent with best regulatory practice adopted in New South Wales, Victoria and Queensland. Accordingly, the ERV test applied is supplementary to the approach adopted in these jurisdictions.

The prescribed ERV test aims to ensure customers are only paying for the least cost alternative supply of energy. For the ERV calculations prescribed by the Western Power access arrangements, an assessment is made to identify where the ERV of assets might be less than their depreciated optimised replacement cost. An example would be where it is more economical (on a whole of life capital and operating cost basis) after taking account of reliability, security of supply and safety considerations for a customer to install local generation than to receive supply from the transmission system.

Notwithstanding the approach adopted in other jurisdictions, the principles of the Western Power access arrangements have been adhered to for this valuation and an ERV analysis has been applied to the Networks asset base for ODV valuation purposes. In undertaking this assessment, the ERV test has been applied to components of the system which are considered to have a risk of economic bypass. In such circumstances, the minimum cost of replacing the system component with the more economic bypass alternative has been considered.

Further, in undertaking this test, it is necessary to have regard to the practicalities of such an approach and its potential inconsistency with the "ordinary course of business" principle applied in the MERA assessment. If the ERV calculation were to be undertaken regardless of the feasibility of an alternative actually being implemented, then inequitable treatment and incorrect price signals may arise. This may also distort the price which a willing purchaser may be prepared to pay for the asset and accordingly, the fair value of the asset for accounting purposes. To adopt an approach without regard to feasibility would result in a valuation of the assets on a greenfields basis.

1.4 Scale and Nature of Replacement

In calculating the replacement cost of an asset, the assumed size of the replacement project has a significant impact on the overall cost determination. The majority of regulators and industry participants in Australia discount the wholesale asset replacement approach (the "greenfields" principle) based on its lack of feasibility and inconsistency with regulatory principles (such principles including accurate price signalling and price consistency over time) and general purchasing practices. However, in assessing replacement on a part by part basis, it is open to interpretation as to how large or small each part should be when calculating a replacement value.

The relative size of the replacement project for infrastructure components has the potential to materially impact the value of the asset base. For example, a large scale replacement project which involves a significant component of the network will often have lower unit labour and materials costs than replacement by smaller sections (due to the contract discounts and bulk material purchases that are likely to occur with a larger scale project as well as the impact of mobilisation costs). Additionally, large scale replacement may infer some reconfiguration of the network, rather than replacing assets according to the current network configuration and actual component ages. Larger scale replacement is likely to involve lower materials and labour costs, on a unit cost basis.

Efficient network businesses will aim to minimise the overall cost of asset management (comprising operations, maintenance and replacement), therefore replacement in "the ordinary course of business" is considered by most regulators and industry participants to be the appropriate, cost-effective replacement project size for asset valuation purposes.

We consider that this approach is consistent with accounting fair value principles. The assumed scale of replacement adopted has been subject to review for reasonableness.

1.5 Capitalisation of Overheads

In assessing current replacement cost, it is normal practice to allow for all costs which would be incurred by the business in replacing its assets. In this regard, allowance is made for the various overhead costs incurred by the business in relation to asset replacement capital expenditure. Such overheads are normally incurred in three areas:

- overhead costs incurred by the engineering function (engineering, procurement and construction management costs, or EPCM costs);

- overhead costs incurred by the finance and administration function including the costs of administering the financial aspects of the capital expenditure programme, costing and budgeting, project financing and general administration; and

- corporate costs such as management salaries and information technology costs.

From an accounting and taxation viewpoint, such costs should be included in the initial recognition of the asset (subject to assessment of fair value). These costs represent costs which would be incurred in bringing the assets to their current location and state.

From a regulatory perspective, the treatment of such costs must be consistent with the manner in which the expenditure is treated for revenue purposes in the underlying access regime. EPCM costs for each project are usually capitalised as they can be readily and directly attributable to the establishment of the asset. Regulators generally adopt the view that "reasonable" or "efficient" overhead costs should be included in the regulatory asset base. This view is consistent with the access pricing regime.

Therefore, in our view, the capitalisation of overheads including some allowance for administrative and corporate costs is justified for both accounting and regulatory purposes. These costs are generally captured in the replacement cost of each asset by applying an overhead rate to the material and labour cost of each asset. The rate adopted must be a commercially acceptable level of overhead to apply to the unit material and labour costs to ensure that overhead costs capitalised within the regulatory asset base are reasonable to attribute to the asset.

1.6 Interest During Construction

Similar to the capitalisation of overheads, from an accounting and taxation valuation viewpoint, such costs will be included within the initial recognition of the asset (subject to assessment of fair value). These costs are those that would be incurred in bringing the assets to their current location and state.

From a regulatory perspective, the treatment of such costs should be consistent with the manner in which the expenditure is treated for revenue purposes in the underlying access regime. Finance charges are generally recovered in regulated revenues through the application of the weighted average cost of capital (WACC) to the RAB. However, the principles of the existing open access pricing regime in Western Australia recognise transmission network assets within the RAB only when these assets are commissioned. No separate allowance is made in the pricing regime for assets under construction.

On this basis, we consider that the transmission RAB should include the capitalisation of interest during construction prior to commissioning as the access regime does not provide a return on expenditure incurred until the asset has been commissioned. Conversely, the distribution network assets are recognised within the RAB when expenditure is incurred. Accordingly for regulatory purposes, no separate allowance is warranted for interest during construction within the distribution network RAB.

From a materiality viewpoint, no allowance will be made for interest during construction where construction of the asset type is generally undertaken in less than twelve months.

1.7 Contingency Costs

Cost overruns in relation to budgeted or estimated costs arise on construction contracts as a result of many factors such as bad weather, unexpected material cost increases and the inevitable inability to forecast future events with complete accuracy. Allowances for contingency costs are made in asset valuations to account for those unforeseen costs which may be incurred in addition to the budgeted or estimated replacement cost of an asset.

As actual unit costs of assets have been used to form the basis of the average unit costs applied in the MERA costing, no separate allowances for contingency costs need to be applied to the unit cost base as most cost variations will have been incorporated into the average actual unit costs used.

1.8 Building Block Unit Costs

The overall cost of installing the optimal MERA asset is established using present day labour charges and modern efficient practices, both in respect of technology and work practices. In addition, competitive and efficient practices are assumed for estimating construction costs. The building block unit costs reflect costs for the planning, design, procurement, construction and commissioning of the assets. However, preliminary design and planning costs are excluded consistent with the replacement concept. The basic building blocks and unit rates to be adopted in the valuation have been reviewed for reasonableness and benchmarked against other Australian utilities.

Where building block unit costs are dependent on costs denominated in foreign currencies, exchange rates applicable as at the date of determination of the building blocks have been adopted. Some foreign exchange rates, particularly the exchange rate of the Australian dollar against the US dollar, have experienced considerable volatility over recent years.

1.9 Asset Lives

The effective working life of an asset is the estimated life of the asset assuming continued use in its present function as part of a continuing business. An asset is considered to be at the end of its economic life when the value of future operating and maintenance costs exceeds its replacement cost or when the asset has become unserviceable or obsolete.

It is critical that depreciation and asset lives equate to the true economic life of the asset so that as far as possible the asset is fully written down to its salvage value (if any) at the time that it is physically replaced or decommissioned (within practical planning constraints).

In general, average asset lives have been applied for classes of assets based on generally accepted industry estimates of economic life. Where the circumstances of material assets or groups of assets have led to reassessment of the lives applied, then lives have been adjusted as appropriate.

There have been cases where assets currently in service have already exceeded their anticipated economic life. This results from:

1. refurbishment or renewal of the asset which has not been appropriately recorded;

2. the specific asset, or group of assets, having a longer economic life than the average life of that asset class; or

3. the assessed economic life for the class of the assets being inaccurate (this has been apparent where significant proportions of an asset of this class are found to exceed their anticipated economic life).

In cases 1 and 2, we have either:

- re-assessed the life based on a planned replacement date; and

- made a nominal estimate of future life having regard to the current capital planning timeframe.

For case 3, the economic life of the asset class has been re-assessed.

1.10 Contributed Assets

Contributed assets and assets for which a cash contribution has been received in the past by Western Power form part of the physical asset base. From a financial accounting and taxation perspective, the valuation approach for these assets should be no different to assets which have been fully funded by Western Power. A third party will pay an identical amount for the remaining service potential. Accordingly, from a commercial valuation perspective it is irrelevant in assessing value whether full cost has been paid by Western Power for these assets. Any fair value reduction arising from an inability to secure a commercial return in each cash generating unit will be applied pro rata over the assets comprising that cash generating unit.

The format of the future regulatory regime will determine whether such assets are included within, or excluded from, the RAB on which a return is allowed. The Networks regulatory valuation has been conducted inclusive of such assets. The resultant asset base may require adjustment for regulatory purposes to remove an allowance for contributed assets. Such adjustment, if required, will be undertaken external to this assessment.

1.11 Residual Value of Assets

Where appropriate to the valuation methodology adopted, residual values have been included. For Networks systems assets, it has been assumed that there is no residual value at the end of their economic life (i.e. they are depreciated to a zero value). For other assets where book value is used as the valuation base, the residual value adopted is as currently recorded by Western Power for accounting purposes. We have reviewed the residual value assumptions adopted for material other assets.

1.12 Capital Spares and Test Equipment

Capital spares and test equipment which is specifically identified have been valued at their estimated market value.

1.13 Leased Assets

Assets subject to finance lease have been included in the accounting and regulatory asset bases, but need to be separately identified for taxation purposes. Assets subject to operating leases are not reflected within the asset base.

1.14 Effective Date of Valuation

The effective date of the valuation is 30 June 2004. The networks assets physically contained in operating asset registers as at 31 December 2003 have been subject to both DORC and ODV assessments using current MERA costs indexed forward using anticipated indices to 30 June 2004. Actual additions over the period to 31 March 2004 and scheduled additions over the period to 30 June 2004 have been added to this base. The transmission networks assets in the operating assets registers at 31 December 2003 have been updated for known projects to 30 June 2005 and the subject to both DORC and ODV assessments. The remaining assets have been based on accounting asset registers updated to 31 December 2003. Our valuations have included depreciation for the six months to 1 July 2004.

The resultant valuations may require minor adjustment should physical additions to 30 June 2004 differ significantly from those anticipated. Western Power will be responsible for these roll forward adjustments, if appropriate.

Western Power has reviewed the appropriateness of the cut-off between the non financial asset information as at 31 December 2003 as provided to us and on which the valuation has been based and the financial records of capital works in progress as at 31 December 2003 together with actual and forecast additions to 30 June 2004. An adjustment has been made to the valuation to reflect distribution assets which have been installed for use but have not been entered into the operational asset registers at 31 December 2003.

1.15 Appropriateness of Valuation Methodologies to Meet Financial Reporting Objectives

Fair value is defined within Australian Accounting Standards (AASB1015) as "*the amount for which an asset could be exchanged, or a liability settled, between knowledgeable willing parties in an arm's length transaction*". For the majority of Western Power's Network assets, fair value is most likely to be determined by reference to the cash flows which are anticipated to be able to be derived from groups of assets forming cash generating units.

Cash flow modelling has not been completed for the cash generating units as at the date of this report. As such, the adoption of DORC for network assets will not necessarily provide a measure of an asset's fair value as defined under Australian Accounting Standards. However, once the cash flow modelling has been completed, should the present value of the cash flows from a cash generating unit be lower than DORC, DORC will provide a suitable basis for allocating the fair value of a cash generating unit to the individual component assets. If the present value of the cash flows is higher than DORC, then DORC values can be taken as representative of fair value of the individual component assets.

2 NETWORKS SPECIFIC VALUATION METHODOLOGY AND ISSUES

The valuation principles for Networks assets are split between Transmission Network assets and Distribution Network assets due to their separate regulatory frameworks.

2.1 Transmission Network Assets – Identification and Inspection

Western Power has two separate transmission networks namely the South West Interconnected System (SWIS) and the North West Interconnected System (NWIS).

The principal elements of the transmission networks include transmission substations and zone substations, interconnected by transmission and subtransmission lines. The transmission networks enable the transportation of electricity from power stations to zone substations and high voltage customer loads. The zone and customer substations provide the interface between the transmission networks and distribution networks.

The transmission network assets comprise:

- **connection assets:** assets at the point of physical interconnection with the transmission networks which are dedicated to a user - that is, at substations including transformers and switchgear, but excluding the incoming line switchgear. Connection assets of generators are referred to as entry assets and for loads they are called exit assets;

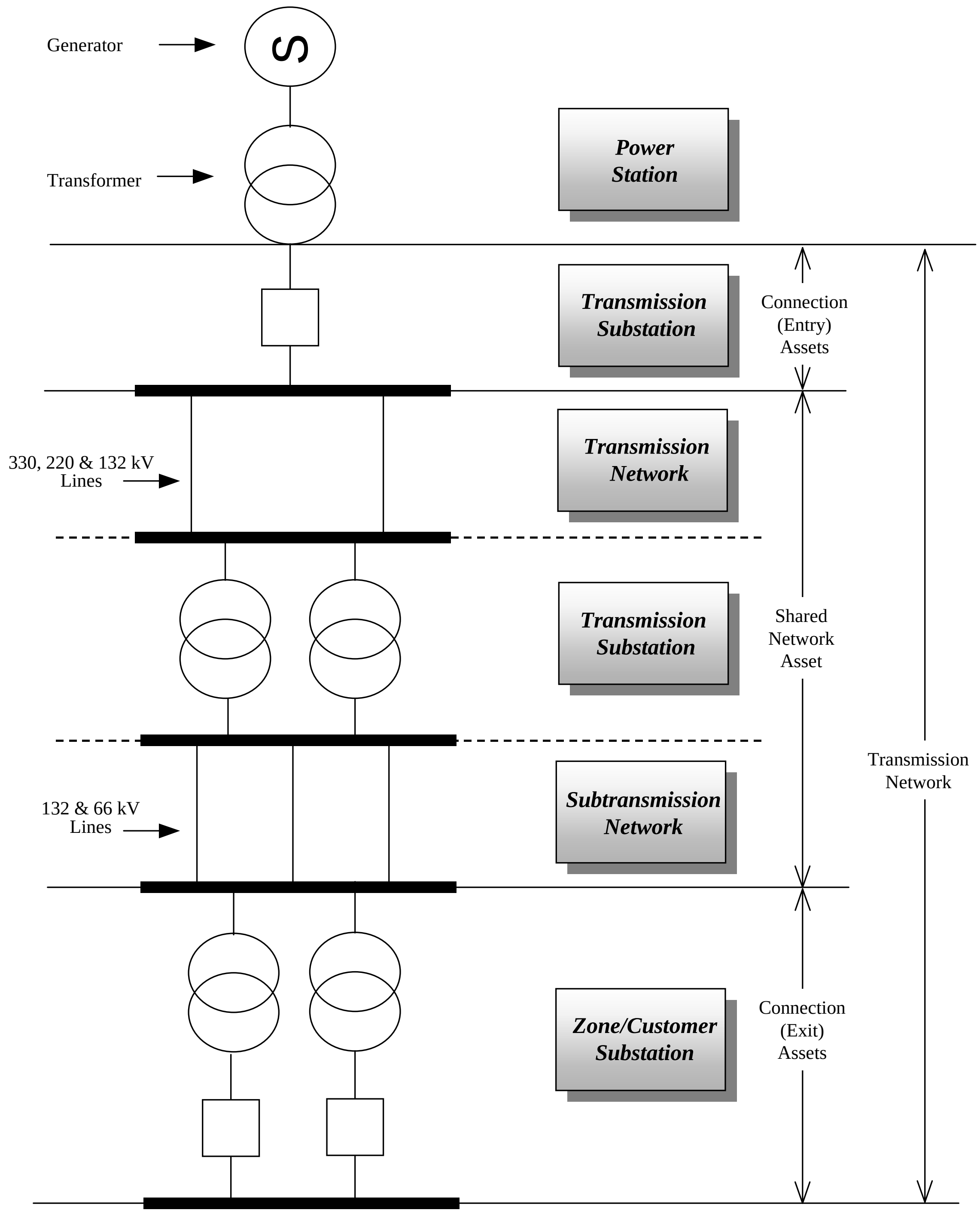
- **shared network assets:** transmission assets in the networks not dedicated to any particular customer, but shared to some extent by network users; and

- **ancillary services assets:** network assets performing an ancillary services functions including:

    - those providing a control system service, for example, system control centres, supervisory control and communications facilities; and
    - those providing a voltage control service in the networks, for example, a proportion of the costs of capacitor and reactor banks in substations.

The following diagram shows in simplified form the principal elements of the transmission networks and the categorisation of the assets described above.

TRANSMISSION NETWORK DIAGRAM



The Western Power transmission network system includes high voltage (330kV, 220 kV, 132kV and 66kV) primary equipment at power stations (excluding low voltage primary equipment and step-up transformers at the generator switchyard), high voltage transmission lines, transmission substations, subtransmission lines and the zone/customer substation equipment at the interface with the distribution business.

Most of the assets of the transmission networks are system assets. Only a relatively minor component of the assets utilised for operation of the transmission network are non-system assets. Such non-system assets include SCADA, other communications assets, buildings and depots for ancillary services.

2.2 Transmission Asset Registers

Western Power maintains two registers for transmission system fixed assets, one for lines and one for substations.

Transmission Line Register – The transmission line register includes all transmission lines, being overhead lines and underground cables at voltages of 66kV and above. It records each line as a whole including its characteristics, such as whether it is of similar construction throughout its length, or a series of sections where each is of different construction. It is therefore possible to give each line or section of line a MERA code which identifies it by voltage, number of circuits, support type and conductor size.

Substation Register – The corresponding substation register includes all transmission substations.

Substations are defined by groups of plant which work together to control the operation of a circuit, which will principally be either a line or a transformer. Each group of plant is said to constitute a bay and it can be configured in a number of different ways depending on its importance and position in the overall system. Flexibility and operability are typically determined by the number of busbars which afford common connection between bays and by the number of circuit breakers assigned to each circuit. These two parameters, plus voltage, give rise to the MERA code by which each bay is identified.

Substations can include additional equipment such as reactors, capacitors and continuously variable compensators for voltage control. Each of these items is also coded for recognition by type and size.

The asset registers are updated by Western Power from reports generated on the commissioning of assets. Accordingly, they represent the current status of the system in terms of operating plant. The register system has developed over a period of years and has been modified as necessary to accommodate the variable nature of the plant and the needs of the valuation process.

Non-System Asset Records – Transmission

Separate non-system transmission asset records are maintained by Western Power in the corporate accounting system asset register and other equipment registers. The register for non-system assets includes communications and SCADA equipment, buildings and office and miscellaneous items.

2.3 Asset Verification and Site Inspections

An asset verification process to check the accuracy and completeness of the asset registers which form the basis of the valuation has been undertaken.

The volume of data stored in the asset registers is very large and therefore a sampling technique has been used to verify the data for the purposes of this asset valuation drawing on the verification work undertaken for the 1995 and 2000 asset valuations.

Where possible substations have been chosen from the group not verified at the 1995 and 2000 valuations.

The verification procedures during the site inspections comprise a review of all primary plant at all voltages by visual audit against line diagrams unique to each substation. The general condition of plant is also sighted as a broad indicator of age and prospective remaining economic life. The year of manufacture of each of the power transformers is also noted.

The nature of the substation equipment and the associated overhead lines or cables is checked against the corresponding entries in the asset registers. The verification process also includes some procedures on plant known to have been decommissioned.

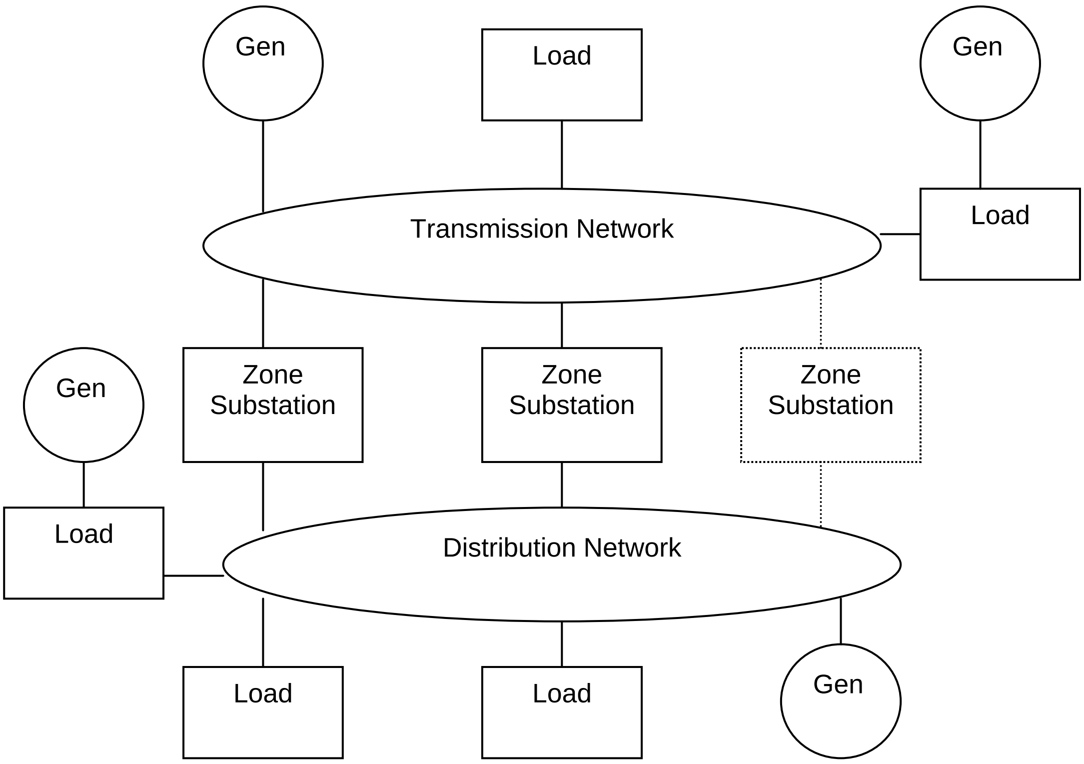
Other than SCADA and communications equipment, non-system transmission assets have not been subject to verification procedures due to the relatively low value attributed to these assets relative to the system assets.

Any discrepancies that have been noted during the verification process have been assessed for their potential impact on the overall valuation assessment.

2.4 Distribution Network Assets – Identification and Inspection

The electricity distribution network is defined in the Western Power distribution access arrangements as “that part or those parts of the system operating at less than 66kV and at a nominal frequency of 50 Hz”. Western Power has two interconnected electricity networks namely the South West Interconnected Network (SWIN) and the North West (Pilbara) Interconnected Network (NWIN). Western Power also operates many Regional Isolated Networks (RIN) supplied from power stations that are not interconnected.

Zone substations provide the interface between the transmission and distribution networks. The distribution network enables the transportation of electricity from the zone substations to customers. The principal elements of the overall electricity system therefore comprise:



Western Power's distribution networks include the following principal elements:

- networks supplied from transmission zone substations operating at voltages of 33kV, 22kV, 19.1kV, 11kV and 6.6kV. Sub-networks contain multiple feeder circuits;
- the feeder circuits emanating from transmission zone substations operating at voltages of 33kV, 22kV, 19.1kV, 12.7kV, 11kV and 6.6kV. These are generally interconnectable between other feeders;
- the distribution network supplied from regional power stations connected to the secondary side of the generator step-up transformers operating at 33kV, 22kV, 19.1kV, 12.7kV, 11kV and 6.6kV;
- distribution transformers to supply power at 415/240V;
- 415/240V low voltage power lines;
- protective devices and switching equipment;
- service cables and meters; and
- street lights.

There are approximately 67,000 kilometres of high voltage distribution mains and 19,000 kilometres of low voltage distribution mains installed in Western Power's interconnected and regional systems. The total installed transformer capacity is approximately 5,600 MVA.

The distribution lines are composed of aluminium and copper overhead conductors and underground cables of both aluminium and copper construction. There are also high tensile steel reinforced overhead conductors and earth wires.

The majority of the network is supplied by three-phase power with the remainder consisting of single phase and two-phase lines. The single-phase system is generally located in areas outside the Perth metropolitan area and major country centres.

South West Interconnected Network (SWIN)

The SWIN extends from Kalbarri in the north, down the west coast of Western Australia and along the southern coast to Bremer Bay and eastwards to the Eastern Goldfields. There are approximately 130 transmission zone substations supplying electricity to the SWIN. Some of these zone substations are either wholly or partly privately owned and accordingly not all lie within the Western Power transmission system and are subject to valuation.

The 6.6kV and 11kV distribution networks are in the older areas of the Perth metropolitan area. The 22kV system supplies the remainder of the Perth metropolitan area. The rural SWIN network is supplied by further 22kV or 33kV networks with many single-phase extensions.

Protective devices are located on feeders emanating from zone substations. These devices provide a measure of protection for the distribution network. Reclosers and sectionalisers are located on the SWIN, NWIN and the regional systems.

North West (Pilbara) Interconnected Network (NWIN)

The NWIN consists of a 22kV and 11kV distribution network. This network extends from Dampier/Karratha to Roebourne/Cape Lambert and across to Port Hedland.

There are approximately 25 zone substations supplying the NWIN being either privately owned or Western Power owned. This valuation exercise has only addressed the Western Power owned zone substations.

Regional Isolated Networks (RIN)

There are 29 RIN's which supply electricity fed by isolated power stations to various parts of the State that are not supplied by the interconnected networks. The regional isolated distribution networks carry power from power stations to consumers. The total installed generating capacity is approximately 110MW. Power station switchgear has been excluded from the network's asset base which follows the asset classification principles set out in the distribution access regulations and is consistent with the proposed asset allocation for accounts purposes**.**

Other System Assets

Most of the assets of the distribution networks are network assets. Only a relatively minor component of the assets utilised for operation of the distribution networks are non-network assets. Such non-network assets include other communications assets, buildings and depots for ancillary services and mobile plant.

2.5 Distribution Asset Registers

The key distribution assets are recorded in an electronic database called DFIS (Distribution Facilities Information System) which contains information on:

- high voltage distribution lines and cables and their environment;
- low voltage distribution lines and cables and their environment;
- transformers;
- switchgear; and
- public lighting.

Western Power has recognised that DFIS has a number of deficiencies which include:

- the lack of data on construction dates for most high and low voltage lines. High and low voltage lines represent about 65% of the distribution asset replacement value. It is therefore necessary to make an estimate of the ages of this equipment based on the installation dates of revenue meters, transformers and other equipment associated with a particular feeder or specific assessments of age by Western Power. The method of estimating age has recently been refined to make use of all available data to minimise the amount of age estimation required;

- there are some component lengths of the various types of construction within individual feeders which are estimated by Western Power. However this comprises less than 2% of the line lengths and there is only a relatively small cost differential between the cost of the largest conductor and the minimum size which has been used as a default;

- the number of revenue meters has been taken from the Customer Information System (CIS) database used for accounting and billing purposes. CIS data has also been used to age the meters based on the recorded installation date; and

- omissions from the transformer database. It has been necessary for Western Power staff to estimate a number of missing ages and sizes for transformers. The effect of this on the overall accuracy of the valuation is not material.

A number of items such as steel reinforcement for poles are not captured by DFIS but are held in a separate register. These items have not been checked in the field survey, and have been reviewed against the previous valuation study for changes in quantities.

The asset registers are updated by Western Power from reports generated on the commissioning of assets. Accordingly, they represent the current status of the system in terms of operating plant.

The accuracy of DFIS has been under continuous review by Western Power. In recent years, errors have been identified and corrected through a managed review project implemented by the Network Asset Management Branch and procedures have been enhanced to improve the recording of additions and deletions.

Whilst the quality of the underlying information in DFIS has improved substantially, there still has been a requirement to undertake some estimation to counter remaining shortcomings in DFIS data. The process of data refinement within DFIS has been reviewed and an assessment made of the extent of reliance on estimates.

2.6 Non-System Asset Records

Separate non-system distribution asset records are maintained by Western Power. The register for non-system assets includes communications, buildings and miscellaneous items.

2.7 Asset Verification and Site Inspections

An asset verification process has been undertaken to check the accuracy and completeness of the asset registers which form the basis of the valuation. Sample checks of the database has been made to provide evidence that the quantities in DFIS are reasonable. A comparison of total physical quantities of major asset categories within the SWIN has also been undertaken with the June 2000 position to assess the reasonableness of the total asset base having regard to additions and deletions in the intervening period.

The volume of data stored in the asset registers is very significant, therefore a sampling technique is used to verify the data for the purposes of this asset valuation.

The sample of system assets has been chosen at random from the asset database and verified in the field as to existence, age and condition. Similarly, a sample of assets identified from the field has been traced to the database.

No physical inspection has been conducted of the assets not contained in DFIS, such as steel reinforcement for poles.

Sample checks on a similar number of feeders in the SWIN and NWIN distribution feeders have been completed. The samples have not included feeders checked in 2000.

Each selected feeder has been physically checked against the DFIS HV switching diagram. Each feeder has been checked for verification of pole top switches, dropout fuses, transformers and underground cable connections to the degree consistent with a ground level survey. The condition of the equipment is reviewed for verification that the appropriate maintenance is being provided to ensure the economic life of the line is achievable. The condition of plant has also been used as an indicator of age. The nature of the equipment and the associated overhead lines or cables is checked against the corresponding entries in the asset registers. A sample verification check has also been performed to ensure that assets relating to overhead lines have been removed where replaced under the undergrounding program.

Non-system assets have not been subject to verification procedures due to the relatively low value attributed to these assets relative to the distribution system as a whole.

Any discrepancies noted during the verification process have been assessed for their potential impact on the overall valuation assessment.

2.8 Basis of Building Blocks

The Networks asset categories broadly fall under the following classifications:

Distribution
- Overhead lines
- Underground cables
- Transformer stations
- Switchgear
- Meters and services
- Public lighting

Transmission
- Overhead lines
- Underground cables
- Substations
- Other substation equipment

The asset registers separately refer to logical identifiable plant types and configurations which can be used as the basis for the allocation of MERA codes. These MERA codes then represent a building block for the purpose of valuation of the network assets as a whole.

Distribution Building Blocks

Building block codes as reflected in the DFIS are set out below.

Code	*Description*
HVCO	High voltage conductor overhead
HVCU	High voltage conductor underground
HVSP	High voltage single phase
LVCO	Low voltage conductor overhead
LVCU	Low voltage conductor underground
DSTR	Distribution transformer
RGTR	Voltage regulator
PTSD	Pole top switch disconnector
RECL	Recloser
SECT	Sectionaliser
DISO	Disconnector
DOF	Drop-out fuse
FSSW	Fuse switch
FSDO	Fuse disconnector overhead
CBDC	Circuit breaker disconnector
CCTB	Circuit breaker

The building block categories adopted for the purposes of this valuation are set out in the following sections.

Overhead Lines

Unit rates have been calculated for each category of distribution lines. The rates are typically based on wood poles but with steel poles for cyclonic regions.

High voltage distribution conductors have been grouped according to size:

- Heavy - greater than 185mm^2
- Medium - less than 185mm^2 and greater than 100mm^2
- Light - less than 100mm^2

Where the conductor size is not specified in DFIS, the following assumptions have been made:

Carrier	*Type*	*Assumption*
HVSP	All	Small
HVCO	Rural	Small
HVCO	Rugged	Small
HVCO	Urban	Medium
LVCU	Rural	Medium
LVCU	Rugged	Medium
LVCU	Urban	Large

The quantity of conductors where size is unknown represents less than 1% of the total network.

Typically, rural lines allow for spans of 120 metres and urban lines of 40 metres, with conductor sizes of light, medium and heavy with due allowance for the various pole construction types required.

A loading factor of 10% has been used for overhead lines in rugged terrain to account for difficult access and clearing. This factor has been applied to the rate for “rural” construction in a particular category of overhead line.

An allowance has been added to the rates for overhead lines in coastal areas to account for high pollution insulators and pole top bonding. These rates are applied to overhead lines within 5 kilometres of the coast in the Perth metropolitan and south country regions and within 15 kilometres in the north country regions. The lines with these characteristics are identified in DFIS.

High voltage overhead lines with underbuilt low voltage are valued as high voltage overhead only. The underbuilt low voltage is valued separately.

The incidence of two high voltage lines on the one pole is low and has been ignored in the valuation. Similarly, service poles are the property of the customer and have not been valued.

Steel reinforcing of poles is not recorded in DFIS (quantities have been estimated by operational personnel to determine a replacement cost). Concrete poles have been installed in the past where suitable wood poles have not been available. Whilst concrete poles have a longer life, wood poles represent a lower cost relative to service life and are used by Western Power in the SWIN over other alternatives such as concrete poles (subject to availability). Replacement of concrete poles has been costed by the use of wood poles.

Underground Cables

Unit rates have been calculated for each category. The unit rates have been refined from information gained from the Perth metropolitan undergrounding project. A separate rate is given for all high voltage underground cable in the Perth central business district.

There is only a limited amount (approximately 76 kilometres) of 33kV underground cable in the distribution system and the majority of it is “small”. Only one rate has been used for 33kV cable.

HV underground with LV underground has been costed as HV underground on its own, based on lengths in the HV data. LV underground with HV underground has been costed as the LV cable plus an installation cost per metre based on lengths in the LV data.

One rate has been used for all instances where two 22kV cables are installed in a common trench because the incidence of this configuration is small. The rate for each multiple LV cable in the one trench is the rate for one cable plus an installation cost per metre for subsequent cables.

Transformer Stations

Regulators, capacitors and special transformers are valued separately. The quantity of unknown transformer sizes is less than 5% of the total. Where transformer sizes are unknown in DFIS, they have been assumed to be 10kVA for pole mount and 25kVA for customer mount in rural areas, and 300kVA for kiosk transformers.

Transformer prices include the cost of installation and housing. Customer housing is given a value per unit to cover installation, but zero value for the housing itself.

Switchgear

Where switchgear is supplied as a single pole unit, for example drop out fuses, they have been valued as a three pole unit in urban areas and as a two pole unit in rural areas. Ringmain units are shown in DFIS as separate switches and fuse switches and are costed as three separate units.

Meters and Services

Unit rates were calculated for each of the tariff types using modern equivalent electronic meters where appropriate. The unit cost allows for the service cable, meter, meter panel and labour. Meters and services have been valued using quantities from CIS.

Public Lighting

Unit rates were separately calculated for each of the public lighting categories, namely lights fitted to overhead line poles and lights fitted to individual poles both with underground cable connections.

Building Block Rates

Western Power has provided unit rates utilising its in-house estimating package known as the Distribution Quotation Management (DQM) system.

NWIN and Regional Building Block Rates

Building block costs from the SWIN have been used as a basis for determining building block rates for the NWIN and the RIN adjusted for the following factors for application in the NWIN and RIN:

- steel pole costs have been substituted for wood poles for overhead lines above the 26^{th} parallel;
- a concrete footing has been allowed for steel pole construction;
- overhead line span lengths have been adjusted to meet structural design limitations;
- termite protection has been allowed for all underground cables; and

- a loading factor has been added to all labour rates for overhead lines and underground cable costs to cover additional allowances for work above the 26th parallel.

Unit Costs of Materials and Labour

The distribution building blocks have been developed using parameters for the key cost inputs of core components.

Labour rates used in the DQM system comprise the base labour rate with allowances for items such as leave, superannuation and workers compensation insurance.

The materials cost estimates in the DQM system are based on annual contracts for supply of all major items with an allowance to cover transport, warehouse and distribution costs.

The rates included for the use of plant on a project are based on external charge-out rates. These rates are based on plant costs plus operating costs, depreciation, insurance, interest and internal overheads and are updated on an annual basis. The plant rates used have been checked against Rawlinson's Australian Construction Handbook.

Transmission Building Blocks

Overhead Lines

Overhead line building blocks relate to operating voltage, type of support structure, number of circuits and conductor size. The MERA codes, and hence the building blocks, for overhead lines are identified in the following form:

VnSxxx

Where:
V is the system voltage
n is the number of circuits
S is the type of support
xxx is the equivalent aluminium area of conductors

There is some aggregation within MERA codes in that a single MERA code has been used to cover a range of construction conductor sizes defined by their equivalent aluminium area. This parameter is used to establish a link between different materials capable of the same electrical performance. A result of banding can be to place a conductor just outside the nominated band in a category which can distort its true value. Where this has been found to occur, the bands have been adjusted to minimise the distortion.

Building block costs for overhead lines are based on tenders and completed contract costs in Australia or by interpolation using historical data which, though not valid in absolute terms, has been found to retain its validity in relative terms. Where actual costs from recent years have been used, these have been inflated to the valuation date and adjusted where relevant by a factor for the relative cost of imported steel.

Adjustments are made where appropriate to arrive at a realistic cost base adjusted for Western Australian conditions. These conditions can have a quite specific impact on the cost base because of the relatively low level of transmission development in Western Australia and the particular conditions of terrain, climate and other factors peculiar to the State.

In assessing the replacement value of each line, it is necessary to recognise the effect on replacement cost of such factors as terrain, wind loadings, remoteness and line length. These factors have been incorporated into the valuation using multipliers on standard building block costs for lines. Standard building block costs are developed on the basis of 100 kilometres of line in rural conditions (assuming essentially flat terrain and easy access with minimal clearing required).

The environment in which a particular line exists determines the multipliers appropriate to its circumstances. To avoid distortions in valuation, a line which is listed in several component sections is assessed on the basis of its overall length to determine the length multiplier (such that the result represents the line as constructed under one contract). This overall multiplier together with the building block line cost is then applied to each section to determine the total line cost. We consider that the costing on this basis is conservative.

All the multipliers are applied to actual section lengths which results in equivalent lengths being valued at the standard building block cost.

Underground Cables

Underground cables are identified by building blocks based on operating voltage and conductor size. Underground cables are assigned MERA codes on the same basis as overhead lines with the structure identifiers “nS” replaced by “UG”. A factor of 0.85 is applied for cables in a non-urban environment.

Substations – Coding and Costing

Substation building blocks relate to switch gear bays and are defined by operating voltage, duty and busbar configuration and the number of circuit breakers. Substations are characterised by a series of interconnected groups or bays of similar plant. For the purpose of MERA coding, items within substations such as transformers, reactors and capacitors each have their own building block defined by operating voltage and rating. Ancillary equipment such as communications and SCADA which are classified as non-system assets are dealt with separately.

Substation bay coding is in the form:

BVxy

Where:

V is the system voltage

x is the duty and busbar configuration
y is the number of circuit breakers

Transformer coding is in the form:

TVzzz
Where:
V is voltage
zzz is the rating in MVA

Reactor coding is in the form:

Rzzz
Where:
zzz is the rating in MVAr

Capacitor coding is in the form:

CVzz
Where:
V is voltage
zz is the rating in MVAr

The building blocks are compiled using parameters for the key cost inputs of core components. Western Power has completed a compilation of building block costs from the material and labour content.

2.9 Overheads

Overheads observed on EPCM projects would typically include all or some of the following items:

- preparation of detailed performance specification;
- incorporation of Conditions of Tendering and Contract;
- calling, receiving and evaluating tenders;
- recommending a preferred tenderer;
- preparation of Contract Documents;
- review of contractor's detailed design proposals;
- supervision of contractor's detailed design proposals;
- supervision of contractor's survey crews;
- full-time supervision of construction;
- supervision of commissioning;
- checking as-installed drawings;
- authorising site variations;
- maintaining physical and financial progress records; and

- reporting to client.

Further costs would be incurred by Western Power in managing an EPCM contractor and at a corporate level.

Overhead rates appropriate to the distribution and transmission networks are assessed by reference to the expenditures currently being incurred by Western Power and to industry benchmarks.

The rate applied to a particular class of asset depends on the complexity of the internal Western Power services required. For example, complex construction projects may require extensive design services and a significant amount of contract management, whereas less complex tasks may only require oversight by the Western Power contract management team. EPCM overhead rates are often higher for distribution assets which are generally more complex and require more internal service than transmission construction projects.

2.10 Asset Lives

The total economic life of an asset is the estimated total period over which the service potential of the asset is expected to be used up from the date of placing the asset into service. In order to allocate depreciation over the life of an asset, standard lives are used. These are the average of the expected total economic lives for a particular class of asset.

The economic lives of transmission and distribution assets are fairly uniform throughout the industry although some variations do occur due to specific climatic extremes. The economic lives adopted in this valuation generally follow those prescribed by New South Wales Treasury and previous Western Power valuations updated for current experience. A notable exception is for transmission lines constructed on wood poles.

Western Power has undertaken an ongoing programme of steel reinforcement of wood pole bases where accelerated deterioration normally occurs below and above the ground line. Asset lives have been re-assessed in the light of the extent of steel reinforcing that has occurred. The potential for increase in distribution and transmission wood pole lives is based on the premise that poles that have been reinforced by the installation of steel reinforcement at the ground line will have an increase in life. The process of reinforcing poles is ongoing, therefore it can be expected that the proportion of reinforced poles, and the average life of overhead lines, will increase over time.

The reinforcement of wood poles by staking with steel sections at the ground line has been in practice since the 1980s. Poles that are reinforced have been shown to provide an average wood pole with a life extension of 15 years to a revised useful life of 50 years. The extension of the wood pole life through reinforcing is reflected by increasing the average age of wood poles based on the proportion that has occurred. Both transmission and distribution asset registers record which poles have been reinforced. However, the level of recording in the distribution register is incomplete.

Where poles require reinforcing, poles are reinforced on average after 20 years of a normal 35 year non-reinforced wood pole life. To determine the current replacement cost of the steel reinforcing used in poles that have been reinforced, current reinforcing costs are discounted to a present value (using a risk free real rate) over the period up to when the reinforcing normally takes place (20 years). The resultant cost is depreciated over the extended 50 year life of a reinforced pole. Mechanisms for the allocation of steel reinforcing costs to specific assets have been developed in conjunction with Western Power.

Remaining Asset Lives and Ages of Distribution Feeders

Where feeders have been the subject of significant capital expenditure, their ages have been adjusted to take account of the extension in life. A formula has been developed for this adjustment. The formula recognises the rejuvenating effect which occurs from the replacement of significant components within individual feeders and weights the asset life extension relative to the proportion of capital replacement made within the feeder.

A minimum residual life of five years is applied to all distribution feeder assets which are not scheduled for earlier decommissioning. This represents the average residual age of all component of the relevant feeder section. Periodic maintenance and refurbishment ensures that feeders are serviceable and reliable. For meters, a shorter residual life of three years has been adopted to reflect the extensive meter replacement program and the generally shorter life of these assets relative to other network assets.

Consideration has been given to the impact that any known or anticipated commissioning or decommissioning of generation assets may have on the lives of transmission and distribution network assets.

2.11 Property Valuations

The definition of "Property" for the purposes of this report includes freehold land, buildings and leasehold improvements on leasehold land.

Leasehold land and buildings are not included in the asset base as their lease costs are regarded as operating costs. Easements are addressed separately below.

Most valuations of network assets include all property (system and non-system) at DORC. In principle, there is no difference between determining the value of land and buildings necessary for the operation of the network or a line or pole, and this is evidenced by the treatment accepted by regulators in other Australian jurisdictions. Unless there are recoverability issues associated with specific property assets, then applying the above principles results in a DORC valuation which equates to the current fair market value. This approach is also consistent with accounting principles.

Western Power's current access regime prescribes that non-system assets be reflected at book value in the RAB. This approach appears to be contrary to common regulatory principles and that adopted by regulators in other Australian jurisdictions. Consistent with the application of best regulatory practice and in anticipation of modification of Western Power’s current regulatory framework, the market value of land is adopted in both the regulatory ODV assessment and for accounting purposes. Land on which system assets have been constructed or which has been acquired for planned expansion of the transmission network system has been reflected at Valuer General assessed values.

Buildings representing network assets have been valued at current construction cost by incorporating cost elements into the building blocks for substations or lines as appropriate.

The property assets associated with the distribution network primarily consist of depots, offices and padmount transformer sites on which infrastructure has been built. Most of the property value associated with the distribution network lies within the depots and offices. For regulatory and accounting purposes, fair value has been adopted. Valuer General assessments have been used for land and, from a materiality perspective, book value has been adopted for buildings other than residential properties, where market value assessments have been applied.

Most of the distribution padmount transformer sites are gifted assets which have been obtained at no cost. Traditionally, Western Power has excluded these items from the RAB, however for accounting purposes they should be reflected at market value. The most recent Valuer General assessed values has been used for this purpose.

2.12 Easement Valuation

All transmission lines are owned and operated under the provisions of the Energy Corporations (Powers) Act 1979 which requires Western Power to purchase an easement for the construction of high voltage lines of 200kV and over. It has been Western Power's policy since 1988 to acquire easements on all new transmission lines of 132kV and above.

The easements primarily relate to land that has been purchased or “gifted” by the State Government whereby only a minimal administration fee was incurred to allow Western Power to access the land.

There are no significant costs for easements held by the distribution networks.

The most recent and comprehensive discussion of this issue is found in the ACCC’s decision paper *NSW and ACT Transmission, Network Revenue Caps, 1999/00-2003/04.* In this decision, the ACCC noted that easements usually have characteristics which are different to other network assets and therefore should not be valued at ODRC but at historical cost. We also note comments in the determination that a registered easement is the right to construct, operate and maintain a power line and does not involve ownership of the land under the line.

Most easements are granted in perpetuity and as such there is no necessity to provide for replacement. Further, the value of the easement is linked to its value in use – ie, if a line is removed, then the easement would have no recoverable value. The report concludes that from a regulatory perspective:

> "*The Commission is concerned that the traditional basis for valuing such assets may serve to provide network owners with windfall gains which do not necessarily*

> *reflect the risk-adjusted cash flow rate of return appropriate to the efficient operation of those businesses.*"[2]

Whilst the Western Power access regime specifies that system assets be valued on the basis of ODV, we acknowledge the ACCC's comments set out above, and all easements have been valued at their historical cost. This treatment is considered to be appropriate from both a regulatory and financial perspective. This value could be regarded as conservative since the value of easements on an ODV basis would be substantially higher than historical cost.

2.13 Underground Asset Valuation

It has been a mandatory requirement since 1991 that all new land subdivisions in the Perth metropolitan area are reticulated by underground power. The State Government has created a program and reserved funding (but not legislated a requirement) to expand the underground electricity network in the Perth metropolitan area. This expansion is planned to be achieved through the continued provision of underground power to new subdivisions and the progressive dismantling of selected areas of existing overhead lines and replacement with underground power. The State Government's stated objective is that through this combination of measures 50% of the homes and businesses in the Perth metropolitan area will have underground power by 2010.

The main reason for the underground replacement program is to increase the aesthetic value of streets and areas where there are overhead wires at present. Underground power also provides greater safety and security of supply as well as reduced maintenance costs.

Whilst the program of dismantling selected overhead lines and replacement with underground power is planned to continue, the identification of the specific areas of the Perth metropolitan area to be subject to undergrounding has not been undertaken beyond the next two year period.

The relevant valuation issues to be addressed in relation to underground power are:

- whether the underground assets should be valued at the DORC of underground assets or at the lower DORC values for overhead assets since the underground assets provide service levels and standards at least equivalent to the overhead assets they have replaced; and

- the remaining life to be applied to overhead assets which are to be replaced as part of the undergrounding program before their normal useful life has expired.

The ODRC principle of applying the lowest whole of life asset costs to an asset could, if improperly applied to underground assets, result in the assets being valued at the lower overhead asset costs, rather than the higher underground cost of network assets. We believe that this would be unreasonable as the higher service standards provided by the

[2] ACCC. *Decision – NSW and ACT Transmission, Network Revenue Caps, 1999/00-2003/04. January 2000, p57.*

underground assets are not excessive. Moreover, once the underground assets come to the end of their service lives, the expectation is that they would be replaced by underground, rather than overhead, assets by a utility acting efficiently and seeking the lowest cost solution to meeting what would have become required service standards at that time.

Incorrect application would also create a strong disincentive to further development of the underground network since Western Power would only receive (and customers would only be charged) a return on the overhead asset cost rather than the actual replacement cost of the underground asset.

The NSW Treasury Paper [3] states that:

> *"Any existing underground reticulation should be valued on the basis of replacement costs for underground reticulation only if it is required by local planning guidelines or where a prudent commercial operator would reticulate these parts of the system underground in the normal course of business based on existing accepted community standards in that location."*

Since Western Power is required to install underground assets as a result of State Government policy, and the underground replacement program provides increased aesthetic, safety and security of supply features as well as reduced maintenance costs, it is appropriate for the existing underground assets to be valued at their full underground replacement cost. This accords with normal distribution industry practice and with normal RAB valuation practice.

The key issue in relation to existing overhead assets is whether the remaining life of the overhead assets which will be replaced by underground assets at some future date should be reduced to reflect that reduced remaining life.

Although approximately 50% of the distribution network in the Perth metropolitan area should have underground assets by 2010, it is difficult to determine exactly which assets will be replaced over this time until specific planning details are developed. The only overhead assets which will be replaced with any certainty are those included in Western Power's two year planning horizon. We consider that the remaining life issue should only be focused on the overhead assets included in the two year planning for these assets – the scope and timing of replacement of other assets is too unclear to estimate new replacement costs or replacement dates.

The key implication is the appropriate treatment of the written down value of the overhead assets which will be decommissioned during the two year planning horizon.

For regulatory purposes, the existing overhead assets which are likely to be replaced over the next two year planning horizon by the undergrounding program should be retained in the valuation and depreciated over their normal useful lives until replaced. Allowance is made within the pricing framework for compensation for early decommissioning through accelerated depreciation provisions.

[3] NSW Treasury. *Technical Paper* December 1995, p 31.

From a financial accounting perspective, the carrying value of lines scheduled for replacement should reflect the shortened remaining life, with the residual value reflecting any compensation receivable on early decommissioning of the assets.

2.14 Rapid Response Transformers

The RRT is a mobile unit rated 33 MVA which can be placed at short notice to take over all or part of the load which was being carried by a substation transformer which has failed in service. The transmission business currently has three RRTs.

In view of the ability to bring in the RRTs to effectively justify the deferral of an augmentation of capacity, which would otherwise be prudent, it is appropriate to classify the RRTs as network assets and these have been included in substation values.

2.15 Joint Networks' Assets

In most cases the distinction between the networks' assets is relatively straight-forward. The allocation is more ambiguous for joint assets which are shared among the businesses.

Examples of joint assets which are typically shared between businesses include customer information systems, corporate accounting systems, computer hardware, buildings and building fitouts.

The CIS is fully allocated to the retail division. Only hardware and software for the exclusive use of the Network's business units is included in the Networks valuation within the category of Other Assets.

We have been advised that there are no significant buildings in the transmission regulatory asset base with shared use. The Western Power head office is excluded from the Networks' asset base and is subject to a separate rental charge.

The distribution and transmission businesses of Western Power have separate SCADA systems. Accordingly, the transmission and distribution SCADA assets are the sole responsibility of the relevant network and therefore the full value of these SCADA assets has been included in the relevant valuation.

The Western Power Networks business shares very few joint assets with either the generation or retail businesses. The transmission assets physically located within generation sites are clearly identified. There is some sharing of depots between the transmission and distribution businesses, but the total value of depots is immaterial and therefore the value of the shared proportions is also immaterial.

2.16 Optimisation

Technical Optimisation

The purpose of technical optimisation is to identify instances of:

- installed over-capacity; and

- sub-optimal network configuration.

Distribution Network Optimisation

Technical optimisation is applied within the following parameters:

- there are no changes in existing points of supply, locations of loads, transmission lines or cable routes, easements or substation sites;

- existing standard voltages have been used;

- standard equipment ratings have been used;

- no change in reliability has been factored in;

- optimisation has been tested against alternative network technology solutions; and

- energy losses are taken into account.

In order to allow for installed over-capacity to cater for load growth, a planning horizon of five years was chosen for the distribution network in accordance with accepted guidelines.

Transformer Utilisation

The overall utilisation of distribution transformers is measured from the ratio of the system peak load in MVA (reduced by the estimated industrial load to allow for non-Western Power installed transformer capacity) and the total installed Western Power owned transformer capacity in MVA. Individual zone substation distribution transformer utilisation is considered to identify over-sized transformers. Optimisation has been considered for installed transformer capacity.

Switchgear Utilisation

The previous valuations identified an excess of pole top isolators on the system and optimised the quantity. This optimisation has been reviewed.

Low Voltage System

General utilisation has been examined to identify scope for technical optimisation

The economic optimisation evaluation has been undertaken by use of modelling to calculate an average cost of supply (in cents/kWh) to customers connected to candidate zone substations (generally remote supply) which have potential exposure to economic optimisation. The average cost of Western Power network supply is compared to an average long run cost of alternative energy supply.

Transmission Network Optimisation

In order to allow for installed over capacity to cater for load growth, a planning horizon of fifteen years was chosen for the transmission network.

General technical optimisations from the previous valuations have been reviewed. These include:

- converting single 330kV circuits built as the only circuit on double circuit structures to single circuit structures where it was unlikely that the second circuit would be erected for 10 to 15 years;
- converting 132kV 1½ circuit breaker switch yards to single busbar except for major switch yards;
- supplying small remote loads by radial transformer feeders with automatic reclose;
- using a modern 3 circuit breaker arrangement for 132kV and 66kV switch yards in zone substations in lieu of the standard 4 circuit breaker arrangement; and
- replacing outdoor 22kV, 11kV and 6.6kV switch yards with indoor switch gear.

In addition, the following technical optimisation tests have been conducted:

- ***Transformer rating*** **–** transformer rating against maximum load is reviewed to identify candidates for reconfiguration based on existing standby requirements;
- ***Lines operating at lower than design voltages*** **–** candidates have been assessed for possible reconfiguration should the design rating not be required within the planning horizon; and
- ***Capacitor bank optimisation*** **–** the requirement for capacitor banks in the Perth metropolitan area has been reviewed in the light of existing transmission capacity to Perth.

A review of the transmission network for economic optimisation has been conducted to ensure consistency with the definition of ODV in Western Power’s Transmission Access Arrangement. The Access Arrangement requires that a review for economic optimisation occurs to ensure that customers are only paying for the lowest cost supply of energy, among all feasible alternatives available.

To undertake this review, assets subject to economic optimisation in the previous valuation have been considered together with a general review of the transmission network for potential economic optimisation.

Using the definition of ODV in Western Power's Transmission Access Arrangement, the value represented in the asset base must equate to the option which delivers the lowest "whole of life" cost from the feasible alternative (the ERV) or the existing asset (on a MERA basis, after technical optimisation). The "whole of life" cost includes both the installation, maintenance and operation costs of the asset.

Where transmission lines are remote from the source of generation, the principles of ERV apply to consider whether a more economic alternative supply source exists. For example, it is feasible that gas turbine generators may be cheaper to install and operate than long transmission lines.

For the ERV assessment:

- alternative options for energy supply that met the same reliability criteria as the current transmission network (after review for reasonableness of the current system reliability) has been considered:

    - close to gas supply – the installation of gas engines and gas turbines are considered as feasible alternatives to transmission lines; and
    - remote from gas supply – diesel engine cost estimates are used for locations remote from gas pipelines; and

- the cost of installing and operating those alternative options has been compared to the installation and operation of the current transmission network on an Equivalent Annuity Cost (EAC) basis (which represents the comparative annual cost of installing and operating all supply options, allowing for the time value of money). The option with the lowest EAC value has been the preferred option.

Appendix B Distribution Schedules

Appendix B-1 MERA Costs and Asset Lives

Table B-1A SWIN Overhead Lines and Underground Cables

ID	BB ID	VOLT	CARRIER	DESCRIPTION	2004 ODV Rate $/km	Life
1	1	33	HVCO LARGE - URBAN	19/3.25AAAC; 40m bays; normal pollution;	$ 53,739	41
2	2	33	HVCO MEDIUM - URBAN	7/4.75AAAC; 40m bays; normal pollution;	$ 52,651	41
3	3	33	HVCO SMALL - URBAN	7/2.50AAAC; 40m bays; normal pollution;	$ 46,969	41
4	4	33	HVCO LARGE - RURAL	HVCO LARGE - RURAL (22kV)	$ 26,553	41
5	5	33	HVCO MEDIUM - RURAL	HVCO MEDIUM - RURAL (22kV)	$ 25,599	41
6	6	33	HVCO SMALL - RURAL	HVCO SMALL - RURAL (22kV)	$ 20,124	41
7	101	33	HVCO LARGE - COAST (URBAN)	$342.945(Int) + HVCO LARGE - URBAN	$ 54,086	41
8	102	33	HVCO MEDIUM - COAST (URBAN)	$342.945(Int) + HVCO MEDIUM - URBAN	$ 52,998	41
9	103	33	HVCO SMALL - COAST (URBAN)	$342.945(Int) + HVCO SMALL - URBAN	$ 47,316	41
10	104	33	HVCO LARGE - COAST (RURAL)	$84.066(Int) + HVCO LARGE - RURAL	$ 26,638	41
11	105	33	HVCO MEDIUM - COAST (RURAL)	$84.066(Int) + HVCO MEDIUM - RURAL	$ 25,684	41
12	106	33	HVCO SMALL - COAST (RURAL)	$84.066(Int) + HVCO SMALL - RURAL	$ 20,210	41
13	107	33	HVCO LARGE - RUGGED	110% HVCO LARGE - RURAL	$ 29,291	41
14	108	33	HVCO MEDIUM - RUGGED	110% HVCO MEDIUM - RURAL	$ 28,242	41
15	109	33	HVCO SMALL - RUGGED	110% HVCO SMALL - RURAL	$ 22,220	41
16	12	33	HVSP (Urban)	HVSP (22kV)	$ 10,787	41
17		33	HVSP - COAST (Urban)	$28(Int) + HVSP	$ 10,815	41
63	126	33	HVSP (Rural)	HVSP (22kV)	$ 10,787	41
64	127	33	HVSP - COAST (Rural)	$28(Int) + HVSP	$ 10,815	41
68	130	33	HVSP (Rugged)	HVSP (22kV)	$ 10,787	41
18	15	33	HVCU	HVCU MEDIUM - RURAL (22kV)	$ 73,998	60
19	17	33	HVCU (MULTIPLE)	HVCU (MULTIPLE) - (22kV)	$ 59,811	60
20	7	22/11/6.6	HVCO LARGE - URBAN	19/3.25AAC; 40m bays; normal pollution;	$ 50,981	41
21	8	22/11/6.6	HVCO MEDIUM - URBAN	7/4.75AAC; 40m bays; normal pollution;	$ 50,289	41
22	9	22/11/6.6	HVCO SMALL - URBAN	7/2.50AAC; 40m bays; normal pollution;	$ 47,170	41
23	4	22/11/6.6	HVCO LARGE - RURAL	19/3.25AAAC; 120m bays; normal pollution;	$ 26,553	41
24	5	22/11/6.6	HVCO MEDIUM - RURAL	7/4.75AAAC; 120m bays; normal pollution;	$ 25,599	41
25	6	22/11/6.6	HVCO SMALL - RURAL	7/2.50AAAC; 120m bays; normal pollution;	$ 20,124	41
26	110	22/11/6.6	HVCO LARGE - COAST (URBAN)	$342.945(Int) + HVCO LARGE - URBAN	$ 51,328	41
27	111	22/11/6.6	HVCO MEDIUM - COAST (URBAN)	$342.945(Int) + HVCO MEDIUM - URBAN	$ 50,636	41
28	112	22/11/6.6	HVCO SMALL - COAST (URBAN)	$342.945(Int) + HVCO SMALL - URBAN	$ 47,517	41
29	113	22/11/6.6	HVCO LARGE - COAST (RURAL)	$84.066(Int) + HVCO LARGE - RURAL	$ 26,638	41
30	114	22/11/6.6	HVCO MEDIUM - COAST (RURAL)	$84.066(Int) + HVCO MEDIUM - RURAL	$ 25,684	41
31	115	22/11/6.6	HVCO SMALL - COAST (RURAL)	$84.066(Int) + HVCO SMALL - RURAL	$ 20,210	41
32	116	22/11/6.6	HVCO LARGE - RUGGED	110% of HVCO LARGE - RURAL	$ 29,291	41
33	117	22/11/6.6	HVCO MEDIUM - RUGGED	110% of HVCO MEDIUM - RURAL	$ 28,242	41
34	118	22/11/6.6	HVCO SMALL - RUGGED	110% of HVCO SMALL - RURAL	$ 22,220	41
35	12	22/11/6.6	HVSP (Urban)	3/2.75 SC/GZ; SWER rural; 5 poles (200m bays); no PTS or Tx poles;	$ 10,787	41
36	119	22/11/6.6	HVSP - COAST (Urban)	$28(Int) + HVSP	$ 10,815	41
65	128	22/11/6.6	HVSP (Rural)	3/2.75 SC/GZ; SWER rural; 5 poles (200m bays); no PTS or Tx poles;	$ 10,787	41
66	129	22/11/6.6	HVSP - COAST (Rural)	$28(Int) + HVSP	$ 10,815	41
67	131	22/11/6.6	HVSP (Rugged)	3/2.75 SC/GZ; SWER rural; 5 poles (200m bays); no PTS or Tx poles;	$ 10,787	41
37	13	22/11/6.6	HVCU - CBD	240sqmm HV; o/t rates; 200m between roads;	$ 115,017	60
38	14	22/11/6.6	HVCU LARGE - URBAN	240sqmm HV(17.1%), 185sqmm HV(82.9%);	$ 84,994	60
39	15	22/11/6.6	HVCU MEDIUM - URBAN	95sqmm HV; 2 o/h cable terminations;	$ 73,998	60
40	16	22/11/6.6	HVCU SMALL - URBAN	35sqmm HV; no st joints;	$ 67,545	60
41	14	22/11/6.6	HVCU LARGE - RURAL	HVCU LARGE - URBAN	$ 84,994	60
42	15	22/11/6.6	HVCU MEDIUM - RURAL	HVCU MEDIUM - URBAN	$ 73,998	60
43	16	22/11/6.6	HVCU SMALL - RURAL	HVCU SMALL - URBAN	$ 67,545	60
44	120	22/11/6.6	HVCU LARGE - RUGGED	110% of HVCU LARGE - RURAL	$ 93,493	60
45	121	22/11/6.6	HVCU MEDIUM - RUGGED	110% of HVCU MEDIUM - RURAL	$ 81,398	60
46	122	22/11/6.6	HVCU SMALL - RUGGED	110% of HVCU SMALL - RURAL	$ 74,300	60
47	14	22/11/6.6	HVCU LARGE - URBAN (HV WITH LV)	HVCU LARGE - URBAN	$ 84,994	60
48	15	22/11/6.6	HVCU MEDIUM - URBAN (HV WITH LV)	HVCU MEDIUM - URBAN	$ 73,998	60
49	16	22/11/6.6	HVCU SMALL - URBAN (HV WITH LV)	HVCU SMALL - URBAN	$ 67,545	60
50	14	22/11/6.6	HVCU LARGE - RURAL (HV WITH LV)	HVCU LARGE - RURAL	$ 84,994	60
51	15	22/11/6.6	HVCU MEDIUM - RURAL (HV WITH LV)	HVCU MEDIUM - RURAL	$ 73,998	60
52	16	22/11/6.6	HVCU SMALL - RURAL (HV WITH LV)	HVCU SMALL - RURAL	$ 67,545	60
53	123	22/11/6.6	HVCU LARGE - RUGGED (HV WITH LV)	HVCU LARGE - RUGGED	$ 93,493	60
54	124	22/11/6.6	HVCU MEDIUM - RUGGED (HV WITH LV)	HVCU MEDIUM - RUGGED	$ 81,398	60
55	125	22/11/6.6	HVCU SMALL - RUGGED (HV WITH LV)	HVCU SMALL - RUGGED	$ 74,300	60
56	17	22/11/6.7	HVCU (MULTIPLE)	95sqmm (ie. medium) HV;	$ 59,811	60
57	10	LV	LVCO (LV ONLY)	19/3.25AAC(6.77%), 7/4.75AAC(57.12%), 7/2.50AAC(33.17%), 95LVABC(2.94%);	$ 38,390	41
58	11	LV	LVCO (LV WITH HV)	19/3.25AAC(6.77%), 7/4.75AAC(57.12%), 7/2.50AAC(33.17%), 95LVABC(2.94%);	$ 17,222	41
59	18	LV	LVCU (LV ONLY)	25sqmm(25.37%), 120sqmm(2.99%), 185sqmm(46.02%), 240sqmm(25.62%);	$ 69,761	60
60	19	LV	LVCU (MULTIPLE)	25sqmm(25.37%), 120sqmm(2.99%), 185sqmm(46.02%), 240sqmm(25.62%);	$ 57,747	60
61	20	LV	LVCU (LV WITH HV)	25sqmm(25.37%), 120sqmm(2.99%), 185sqmm(46.02%), 240sqmm(25.62%);	$ 46,835	60
62	21	LV	LVCU - CBD	240sqmm LV; o/t rates; 200m between roads;	$ 99,603	60

Table B-1B Valuation Replacement Unit Costs - Substations

ID	BB ID	RATING (Kva)	Phases	Mounting	Description	204 ODV Rate - 22kV	2004 ODV Rate - 33kV	LIFE
1	1	5	1	POLE	1 bush pole-top tx w/o DOF	$ 3,211	$ 2,970	35
2	2	10	1	CUST	10kVA 1phase rural SPURS	$ 4,981	$ 5,264	35
3	2	10	1	KISK	10kVA 1phase rural SPURS	$ 4,981	$ 5,264	35
4	1	10	1	POLE	1 bush pole-top tx w/o DOF	$ 3,211	$ 2,970	35
5	7	15	3	POLE	25kVA 3ph pole-top tx	$ 7,045	$ 8,586	35
6	3	20	1	KISK	25kVA rural SPUDS	$ 9,677	$ -	35
7	5	20	1	POLE	25kVA rural 1 bush pole-top tx	$ 4,031	$ 4,253	35
8	3	25	1	KISK	25kVA rural SPUDS	$ 9,677	$ 9,900	35
9	4	25	1	PILL	25kVA rural SPURS	$ 6,406	$ -	35
10	5	25	1	POLE	25kVA rural 1 bush pole-top tx	$ 4,031	$ 4,253	35
11	6	25	3	CUST	25kVA 3ph tx mounted on stand	$ 6,875	$ 8,416	35
12	7	25	3	POLE	25kVA 3ph pole-top tx	$ 7,045	$ 8,586	35
13	7	30	3	POLE	25kVA 3ph pole-top tx	$ 7,045	$ 8,586	35
14	8	50	1	POLE	50kVA 1ph special step down	$ 8,161	$ 13,153	35
15	0	50	3	CUST	50kVA 3ph customer s/s tx	$ 12,350	$ -	35
16	0	50	3	KISK	50kVA 3ph kiosk tx	$ 12,405	$ -	35
17	9	50	3	POLE	63kVA 3ph poletop tx	$ 8,747	$ 10,490	35
18	9	63	3	POLE	63kVA 3ph poletop tx	$ 8,747	$ 10,490	35
19	10	75	3	POLE	100kVA 3ph pole-top tx	$ 11,289	$ 12,090	35
20	10	100	1	POLE	100kVA 3ph pole-top tx	$ 11,289	$ 12,090	35
21	0	100	3	CUST	100kVA 3ph customer s/s tx	$ 15,892	$ 16,692	35
22	0	100	3	KISK	100kVA 3ph kiosk tx	$ 14,733	$ 15,533	35
23	10	100	3	POLE	100kVA 3ph pole-top tx	$ 11,289	$ 12,090	35
24	0	150	3	POLE	150kVA 3ph pole tx	$ 12,144	$ -	35
25	13	160	3	CUST	160kVA nonMPS district indoor tx	$ 18,631	$ -	35
26	18	160	3	KISK	160kVA MPS district outdoor tx	$ 15,712	$ -	35
27	11	200	1	POLE	200kVA 3ph pole-top tx	$ 13,275	$ 16,013	35
28	0	200	3	CUST	200kVA 3ph customer s/s tx	$ 19,395	$ 20,195	35
29	0	200	3	KISK	200kVA 3ph kiosk tx	$ 16,359	$ 17,159	35
30	11	200	3	POLE	200kVA 3ph pole-top tx	$ 13,275	$ 16,013	35
31	11	200	3	TPOL	200kVA 3ph pole-top tx	$ 13,275	$ 16,013	35
32	14	300	3	CUST	315kVA nonMPS district indoor tx	$ 20,949	$ 17,865	35
33	19	300	3	KISK	315kVA MPS district outdoor tx (22kV) .	$ 18,137	$ 28,587	35
34	12	300	3	POLE	315kVA 3ph pole-top tx	$ 17,624	$ 18,162	35
35	14	315	3	CUST	315kVA nonMPS district indoor tx	$ 20,949	$ 17,865	35
36	19	315	3	KISK	315kVA MPS district outdoor tx (22kV) .	$ 18,137	$ 28,587	35
37	12	315	3	POLE	315kVA 3ph pole-top tx	$ 17,624	$ 18,162	35
38	15	500	3	CUST	500kVA nonMPS district indoor tx	$ 24,497	$ 21,414	35
39	20	500	3	KISK	500kVA MPS district outdoor tx / IPS s	$ 21,742	$ 35,696	35
40	0	500	3	POLE	500kVA 3ph pole tx	$ 21,716	$ 22,255	35
41	16	630	3	CUST	630kVA nonMPS district indoor tx	$ 31,751	$ -	35
42	21	630	3	KISK	630kVA MPS district outdoor tx	$ 29,398	$ -	35
43	0	750	3	CUST	750kVA customer s/s tx	$ 33,563	$ -	35
44	0	750	3	KISK	750kVA kiosk tx	$ 32,551	$ -	35
45	0	750	3	POLE	750kVA pole tx	$ 26,776	$ -	35
46	17	1000	3	CUST	1000kVA nonMPS district indoor tx	$ 36,457	$ 33,373	35
47	22	1000	3	KISK	1000kVA nonMPS district outdoor tx	$ 37,649	$ -	35
48	0	1000	3	POLE	1000kVA pole tx	$ 30,824	$ 31,363	35
49	0	1500	3	CUST	1500kVA customer s/s tx	$ 54,815	$ -	35
50	0	2000	3	CUST	2000kVA customer s/s tx	$ 71,007	$ -	35
51	0	5	1	KISK	5KVA KISK	$ 2,080	$ -	35
52	0	5	3	KISK	5KVA KISK	$ 2,080	$ -	35
53	0	10	3	KISK	10kVA KISK	$ 4,981	$ -	35
54	0	50	1	KISK	50KVA KISK	$ 12,404	$ -	35
55	0	50	3	KISK	50KVA KISK	$ -	$ 12,405	35
56	0	63	3	KISK	63KVA KISK	$ 12,911	$ -	35
57	0	1000	3	KISK	1000KVA KISK	$ -	$ 37,649	35
58	0	5	1	CUST	5KVA CUST	$ 3,280	$ 3,280	35
59	0	10	3	CUST	10KVA CUST	$ 4,981	$ -	35
60	0	25	1	CUST	25KVA CUST	$ 6,836	$ 6,836	35
61	0	50	1	CUST	50KVA CUST	$ 12,350	$ -	35
62	0	50	3	CUST	50KVA CUST	$ -	$ 12,350	35
63	0	75	3	CUST	75KVA CUST	$ 14,374	$ -	35
64	0	160	3	CUST	75KVA CUST	$ 18,631	$ 18,631	35
65	0	315	3	CUST	315KVA CUST	$ 20,948	$ 20,948	35
66	0	630	3	CUST	630KVA CUST	$ 31,750	$ 21,630	35
67	0	1500	3	CUST	1500KVA CUST	$ 54,815	$ -	35
68	0	5	3	POLE	5KVA POLE	$ 2,191	$ 2,191	35
69	0	10	3	POLE	10KVA POLE	$ 3,211	$ -	35
70	0	15	3	POLE	15KVA POLE	$ 3,405	$ 3,405	35
71	0	20	1	POLE	20KVA POLE	$ 3,709	$ -	35
72	0	30	3	POLE	30KVA POLE	$ 7,328	$ -	35
73	0	50	1	POLE	50KVA POLE	$ 8,239	$ -	35
74	0	75	3	POLE	75KVA POLE	$ 9,344	$ 9,344	35
75	0	100	1	POLE	100KVA POLE	$ 11,289	$ 11,289	35
76	0	150	3	POLE	100KVA POLE	$ 12,382	$ -	35

Table B-1C Valuation Replacement Unit Costs – Meters

Metering Building Block Rates for 2004 ODV

Summary Meter Type	Description	Cost Basis	2004 Cost		Life
0098	3 ph t1	JW0209	**$**	**24,871**	**25**
0101	1ph direct sm pow	JW0027	**$**	**540**	**25**
0104	t1	JW0049	**$**	**23,552**	**25**
0111	s1	JW0048	**$**	**4,267**	**25**
0114	1ph direct b1	JW0034	**$**	**562**	**25**
0121	t1	JW0052	**$**	**23,539**	**25**
0123	3ph ct tou r1	JW0105	**$**	**1,972**	**25**
0136	3ph ct tou r1	JW0106	**$**	**1,972**	**25**
0137	3ph ct tou r1	JW0107	**$**	**1,972**	**25**
0138	3ph ct tou r1	JW0108	**$**	**1,972**	**25**
0139	3ph ct tou r1	JW0109	**$**	**1,972**	**25**
0140	3ph ct tou r1	JW0110	**$**	**1,959**	**25**
0141	3ph ct tou r1	JW0111	**$**	**1,972**	**25**
0142	3ph ct tou r1	JW0112	**$**	**1,972**	**25**
0143	3ph ct tou r1	JW0113	**$**	**1,972**	**25**
0144	3ph ct tou r1	JW0114	**$**	**1,972**	**25**
0148	direct 3 ph tou r1	JW0104	**$**	**1,199**	**25**
0149	1 ph tou r1	JW0041	**$**	**510**	**25**
0150	3 ph sm pow direct	JW0035	**$**	**1,187**	**25**
0155	3 phase ct tou sm pow	JW0106	**$**	**1,690**	**25**
0160	1 phase electric direct remote read	JW0029	**$**	**704**	**25**
0180	3 phase electric direct	JW0030	**$**	**571**	**25**
15D	single phase electric direct	JW0042	**$**	**325**	**25**
UNK	single phase electric direct	JW0042	**$**	**325**	**25**

Table B-1D Street Lighting

SHARED POLE			2004 ODV	
* assume S/L onto existing LV				
* includes WPC supply & install, fuse, lamp, luminaire, pe cell, connection				
LAMP				
50W				
80W				
125W				
150W				
250W				
		Average Cost	**$ 353.13**	
OWN POLE				
* includes WPC supply & install, fuse, lamp, luminaire, steel standard pole, pe cell, connection				
a) Without LV connection cost:				
POLE				
6.5m single	50W			
6.5m single	80W			
6.5m single	125W			
10.5m single	150W			
12.5m single	150W			
12.5m single	250W			
12.5m double	250W			
		Average Cost	**$ 818.73**	
b) With LV connection cost:				
POLE	LAMP			
6.5m single	50W			
6.5m single	80W			
6.5m single	125W			
10.5m single	150W			
12.5m single	150W			
12.5m single	250W			
12.5m double	250W			
		Average Cost	**$ 1,480.47**	

Table B-1E Switchgear

ID	BB ID	Terrain	Distribution Level	Equipment Code	Description	ODV 2004 Rate	Life
1	2		LVUG	LVDF	low volt distribution frame	$ 2,985	35
2	3	URBAN	HVOH	DISO	high volt 3ph isolators	$ 1,346	35
3	4	RURAL	HVOH	DISO	high volt 3,2,1ph isolator	$ 1,040	35
4	5	URBAN	HVOH	DOF	high volt 3ph drop out fuses	$ 1,191	35
5	6	RURAL	HVOH	DOF	high volt 3,2,1ph drop out fuses	$ 936	35
6	7		HVOH	PTSD	high volt 3ph pole top switch	$ 5,131	35
7	8	URBAN	HVOH	RECL	high volt 3ph recloser	$ 26,213	35
8	9	RURAL	HVOH	RECL	high volt 1ph recloser	$ 6,941	35
9	10	URBAN	HVOH	SECT	high volt 3ph sectionaliser	$ 13,147	35
10	11	RURAL	HVOH	SECT	high volt 1ph sectionaliser	$ 1,395	35
11	1		HVUG	FSSW	HV fuse switch (switchgear unit)	$ 6,767	35
12	1		HVUG	SWDC	HV isolator (switchgear unit)	$ 8,040	35
13	12		LVOH	DISO	low volt 3x1ph o/h isolators	$ 286	35
14	13	URBAN	LVOH	FSDO	low volt o/h fuse disconnect	$ 651	35
15	13	RURAL	LVOH	FSDO	low volt o/h fuse disconnect	$ 651	35
16	14		LVUG	CBDC	low volt circuit breaker disconnect (u/g)	$ 1,662	35
17	15		LVUG	CCTB	low volt circuit breaker (u/g)	$ 1,371	35
18	15		LVUG	DISU	low volt disconnect (u/g)	$ 1,371	35
19	16		LVUG	FSDU	low volt fuse disconnector (u/g)	$ 926	35

Table B-1F Overhead Lines and Underground Cables Regional – Below 26deg

					2004 ODV Rate	
ID	**BB ID**	**VOLT**	**CARRIER**	**DESCRIPTION**	**$/km**	**Life**
1	1	33	HVCO LARGE - URBAN	19/3.25AAAC; 40m bays; normal pollution;	$ 53,739	41
2	2	33	HVCO MEDIUM - URBAN	7/4.75AAAC; 40m bays; normal pollution;	$ 52,651	41
3	3	33	HVCO SMALL - URBAN	7/2.50AAAC; 40m bays; normal pollution;	$ 46,969	41
4	4	33	HVCO LARGE - RURAL	HVCO LARGE - RURAL (22kV)	$ 26,553	41
5	5	33	HVCO MEDIUM - RURAL	HVCO MEDIUM - RURAL (22kV)	$ 25,599	41
6	6	33	HVCO SMALL - RURAL	HVCO SMALL - RURAL (22kV)	$ 20,124	41
16	12	33	HVSP (Urban)	HVSP (22kV)	$ 10,787	41
63	126	33	HVSP (Rural)	HVSP (22kV)	$ 10,787	41
18	15	33	HVCU	HVCU MEDIUM - RURAL (22kV)	$ 87,174	60
19	17	33	HVCU (MULTIPLE)	HVCU (MULTIPLE) - (22kV)	$ 68,631	60
20	7	22/11/6.6	HVCO LARGE - URBAN	19/3.25AAC; 40m bays; normal pollution;	$ 50,981	41
21	8	22/11/6.6	HVCO MEDIUM - URBAN	7/4.75AAC; 40m bays; normal pollution;	$ 50,289	41
22	9	22/11/6.6	HVCO SMALL - URBAN	7/2.50AAC; 40m bays; normal pollution;	$ 47,170	41
23	4	22/11/6.6	HVCO LARGE - RURAL	19/3.25AAAC; 120m bays; normal pollution;	$ 26,553	41
24	5	22/11/6.6	HVCO MEDIUM - RURAL	7/4.75AAAC; 120m bays; normal pollution;	$ 25,599	41
25	6	22/11/6.6	HVCO SMALL - RURAL	7/2.50AAAC; 120m bays; normal pollution;	$ 20,124	41
35	12	22/11/6.6	HVSP (Urban)	3/2.75 SC/GZ; SWER rural; 5 poles (200m bays);	$ 10,787	41
65	128	22/11/6.6	HVSP (Rural)	3/2.75 SC/GZ; SWER rural; 5 poles (200m bays);	$ 10,787	41
37	13	22/11/6.6	HVCU - CBD	185sqmm HV; o/t rates; 200m between roads;	$ 128,193	60
38	14	22/11/6.6	HVCU LARGE - URBAN	185sqmm HV; 2 o/h cable terminations;	$ 98,170	60
39	15	22/11/6.6	HVCU MEDIUM - URBAN	95sqmm HV; 2 o/h cable terminations;	$ 87,174	60
40	16	22/11/6.6	HVCU SMALL - URBAN	35sqmm HV; no st joints;	$ 72,008	60
41	14	22/11/6.6	HVCU LARGE - RURAL	HVCU LARGE - URBAN	$ 98,170	60
42	15	22/11/6.6	HVCU MEDIUM - RURAL	HVCU MEDIUM - URBAN	$ 87,174	60
43	16	22/11/6.6	HVCU SMALL - RURAL	HVCU SMALL - URBAN	$ 72,008	60
47	14	22/11/6.6	HVCU LARGE - URBAN (HV WITH LV)	HVCU LARGE - URBAN	$ 98,170	60
48	15	22/11/6.6	HVCU MEDIUM - URBAN (HV WITH LV)	HVCU MEDIUM - URBAN	$ 87,174	60
49	16	22/11/6.6	HVCU SMALL - URBAN (HV WITH LV)	HVCU SMALL - URBAN	$ 72,008	60
50	14	22/11/6.6	HVCU LARGE - RURAL (HV WITH LV)	HVCU LARGE - RURAL	$ 98,170	60
51	15	22/11/6.6	HVCU MEDIUM - RURAL (HV WITH LV)	HVCU MEDIUM - RURAL	$ 87,174	60
52	16	22/11/6.6	HVCU SMALL - RURAL (HV WITH LV)	HVCU SMALL - RURAL	$ 72,008	60
56	17	22/11/6.7	HVCU (MULTIPLE)	185sqmm & 35sqmm (50% ea) HV;	$ 68,631	60
57	10	LV	LVCO (LV ONLY)	19/3.25AAC(6.77%), 7/4.75AAC(57.12%), 7/2.50AAC(33.17%)	$ 38,390	41
58	11	LV	LVCO (LV WITH HV)	19/3.25AAC(6.77%), 7/4.75AAC(57.12%), 7/2.50AAC(33.17%)	$ 17,222	41
59	18	LV	LVCU (LV ONLY)	25sqmm(25.37%), 185sqmm(74.63%); pillar every 39.27m;	$ 71,330	60
60	19	LV	LVCU (MULTIPLE)	25sqmm(25.37%), 185sqmm(74.63%); pillar every 39.27m;	$ 59,316	60
61	20	LV	LVCU (LV WITH HV)	25sqmm(25.37%), 185sqmm(74.63%); pillar every 39.27m;	$ 48,404	60
62	21	LV	LVCU - CBD	185sqmm LV; o/t rates;	$ 100,079	60

Table B-1G Overhead Lines and Underground Cables NWIN and Regional – Above 26deg

ID	BB ID	VOLT	CARRIER	DESCRIPTION	2004 ODV Rate $/km	Life
1	1	33	HVCO LARGE - URBAN	19/3.25AAAC; 40m bays; normal pollution;	$ 71,670	50
2	2	33	HVCO MEDIUM - URBAN	7/4.75AAAC; 40m bays; normal pollution;	$ 70,581	50
3	3	33	HVCO SMALL - URBAN	7/2.50AAAC; 40m bays; normal pollution;	$ 64,899	50
4	4	33	HVCO LARGE - RURAL	HVCO LARGE - RURAL (22kV)	$ 37,822	50
5	5	33	HVCO MEDIUM - RURAL	HVCO MEDIUM - RURAL (22kV)	$ 36,858	50
6	6	33	HVCO SMALL - RURAL	HVCO SMALL - RURAL (22kV)	$ 31,361	50
16	12	33	HVSP (Urban)	HVSP (22kV)	$ 14,573	50
63	126	33	HVSP (Rural)	HVSP (22kV)	$ 14,573	50
18	15	33	HVCU	HVCU MEDIUM - RURAL (22kV)	$ 97,213	60
19	17	33	HVCU (MULTIPLE)	HVCU (MULTIPLE) - (22kV)	$ 75,126	60
20	7	22/11/6.6	HVCO LARGE - URBAN	19/3.25AAC; 40m bays; normal pollution;	$ 68,911	50
21	8	22/11/6.6	HVCO MEDIUM - URBAN	7/4.75AAC; 40m bays; normal pollution;	$ 68,220	50
22	9	22/11/6.6	HVCO SMALL - URBAN	7/2.50AAC; 40m bays; normal pollution;	$ 65,101	50
23	4	22/11/6.6	HVCO LARGE - RURAL	19/3.25AAAC; 120m bays; normal pollution;	$ 37,822	50
24	5	22/11/6.6	HVCO MEDIUM - RURAL	7/4.75AAAC; 120m bays; normal pollution;	$ 36,858	50
25	6	22/11/6.6	HVCO SMALL - RURAL	7/2.50AAAC; 120m bays; normal pollution;	$ 31,361	50
35	12	22/11/6.6	HVSP (Urban)	3/2.75 SC/GZ; SWER rural; 5 poles (200m bays);	$ 14,573	50
65	128	22/11/6.6	HVSP (Rural)	3/2.75 SC/GZ; SWER rural; 5 poles (200m bays);	$ 14,573	50
37	13	22/11/6.6	HVCU - CBD	185sqmm HV; o/t rates; 200m between roads;	$ 140,267	60
38	14	22/11/6.6	HVCU LARGE - URBAN	185sqmm HV; 2 o/h cable terminations; 3 straight joints;	$ 109,230	60
39	15	22/11/6.6	HVCU MEDIUM - URBAN	95sqmm HV; 2 o/h cable terminations; 3 straight joints;	$ 97,213	60
40	16	22/11/6.6	HVCU SMALL - URBAN	35sqmm HV; no st joints; 5 o/h cable terminations	$ 82,826	60
41	14	22/11/6.6	HVCU LARGE - RURAL	HVCU LARGE - URBAN	$ 109,230	60
42	15	22/11/6.6	HVCU MEDIUM - RURAL	HVCU MEDIUM - URBAN	$ 97,213	60
43	16	22/11/6.6	HVCU SMALL - RURAL	HVCU SMALL - URBAN	$ 82,826	60
47	14	22/11/6.6	HVCU LARGE - URBAN (HV WITH LV)	HVCU LARGE - URBAN	$ 109,230	60
48	15	22/11/6.6	HVCU MEDIUM - URBAN (HV WITH LV)	HVCU MEDIUM - URBAN	$ 97,213	60
49	16	22/11/6.6	HVCU SMALL - URBAN (HV WITH LV)	HVCU SMALL - URBAN	$ 82,826	60
50	14	22/11/6.6	HVCU LARGE - RURAL (HV WITH LV)	HVCU LARGE - RURAL	$ 109,230	60
51	15	22/11/6.6	HVCU MEDIUM - RURAL (HV WITH LV)	HVCU MEDIUM - RURAL	$ 97,213	60
52	16	22/11/6.6	HVCU SMALL - RURAL (HV WITH LV)	HVCU SMALL - RURAL	$ 82,826	60
56	17	22/11/6.7	HVCU (MULTIPLE)	185sqmm & 35sqmm (50% ea) HV; 2 o/h cable terminations;	$ 75,126	60
57	10	LV	LVCO (LV ONLY)	19/3.25AAC(6.77%), 7/4.75AAC(57.12%), 7/2.50AAC(33.17%)	$ 57,453	50
58	11	LV	LVCO (LV WITH HV)	19/3.25AAC(6.77%), 7/4.75AAC(57.12%), 7/2.50AAC(33.17%),	$ 18,899	50
59	18	LV	LVCU (LV ONLY)	25sqmm(25.37%), 185sqmm(74.63%); pillar every 39.27m;	$ 82,874	60
60	19	LV	LVCU (MULTIPLE)	25sqmm(25.37%), 185sqmm(74.63%); pillar every 39.27m;	$ 67,860	60
61	20	LV	LVCU (LV WITH HV)	25sqmm(25.37%), 185sqmm(74.63%); pillar every 39.27m;	$ 54,227	60
62	21	LV	LVCU - CBD	185sqmm LV; o/t rates; 200m between roads;	$ 119,148	60

Table B-1H Distribution Asset Valuation – Summary of Standard Lives Adopted

Item	2000 Valuation	2004 Valuation	Comments
Overhead distribution lines			
- Wood pole lines	40	41	Note1
- Steel pole lines	50	50	
Reinforcement of wood poles	30	30	
Underground cables	60	60	
Transformers	35	35	
Switchgear	35	35	
Public lighting	20	20	
Meters and services	25	25	

Notes:

1.

Standard wood pole life	35	35
Increase in wood pole life from steel reinforcement	15	15
% of wood poles steel reinforced	30-40%	40%
Pro-rata increase in service life of wood poles	5	6
Adjusted wood pole line life	**40**	**41**

Appendix B-2 NWIN and Regional Building Block Adjustments

NWIN and Regional Building Block Rates

Building block costs from the SWIN have been used as a basis for determining building block rates for the NWIN and RIN adjusted for the following factors for application in the NWIN and RIN:

- Steel pole costs have been substituted for wood poles for overhead lines above the 26^{th} Parallel;
- a concrete footing has been allowed at $250 for steel pole construction;
- overhead line span lengths have been adjusted to meet structural design limitations;
- termite protection has been allowed for all underground cables; and
- a loading factor of 25% has been added to all labour rates for overhead lines and underground cable costs to cover additional allowances for work above the 26^{th} Parallel.

A table of building block costs for overhead lines and underground cables for the NWIN and RIN are included in Appendix A - tables A6 and A7. All other building block costs are the same as for the SWIN.

Rural 3 phase pole spacing is 100m (compared to 120 in SWIN) as per standard structural design. A pro-rata adjustment is made to pole materials, labour and plant costs within the building blocks.

Appendix B-3 Ageing Formula

The 2004 Distribution asset revaluation involves determining the DORC of the distribution system asset. The DORC is the replacement cost of the existing fixed assets at modern equivalent replacement cost which have been optimised from an engineering standpoint and depreciated according to their age.

There are over 3 million assets in the DFIS system that stores data on the key distribution system assets including:

- High voltage distribution lines
- Low voltage distribution lines
- Transformers
- Switchgear
- Street lighting

To accurately determine the age of an asset requires the recording of an accurate date of installation of the asset. Although recently installed assets have accurate installation data recorded in the relevant systems, historically the date of installation was not recorded when assets were installed. The lack of installation dates for older assets means that the actual age of a significant proportion of asset is not known. Installation dates are either not defined, unreliable if older than 1950, or have default dates such as 1 January 1901 or 1 July 1970. The proportion of these assets is diminishing as new infrastructure is built and old infrastructure is replaced or decommissioned.

To enable the DORC to be calculated the ages of the assets are required. The methodology to calculate an average feeder age that is applied to each of the assets forming the feeder is outlined in the following paragraphs. This resulting average feeder age is used as an input into the distribution asset valuation model to calculate the DRC of the asset.

Methodology

The key assumptions behind the algorithm to determine an average feeder age for the 2004 DORC are:

- Installation dates of meters and therefore meter ages from the CIS are assumed to be correct (approximately 1% of the data is missing or ascribed a default date – these meters are assigned an age of 50 years)

- Average feeder ages determined for the 2000 distribution system valuation were determined in a reasonable manner.

A considerable amount of work was done during the 2000 valuation to develop comprehensive estimates of average feeder ages. The average feeder ages were developed using a combination of two approaches. The first approach involved taking the average age of all meters on a feeder. To this average age period of 4 years is added.

Meter installation dates are a good representation of the actual progressive expansion of the network, given that the network is constructed prior to the meters being installed; and 4 years is a conservative figure to reflect both the average take-up time of customer connections to the feeder and a small number of meter changes over time.

In some cases, this method results in an unacceptably high average feeder age, especially in areas where considerable undergrounding or reinforcement work has been performed. For example, in Cottesloe the average meter ages are around 20 years old even though the distribution network has been substantially replaced and is about 6 years old. To overcome this problem numerous feeders had their age individually assessed in 2000.

For the 2004 valuation, the following methodology has been adopted:

1. Calculate the average meter age plus 4 years for each distribution feeder in 2004.

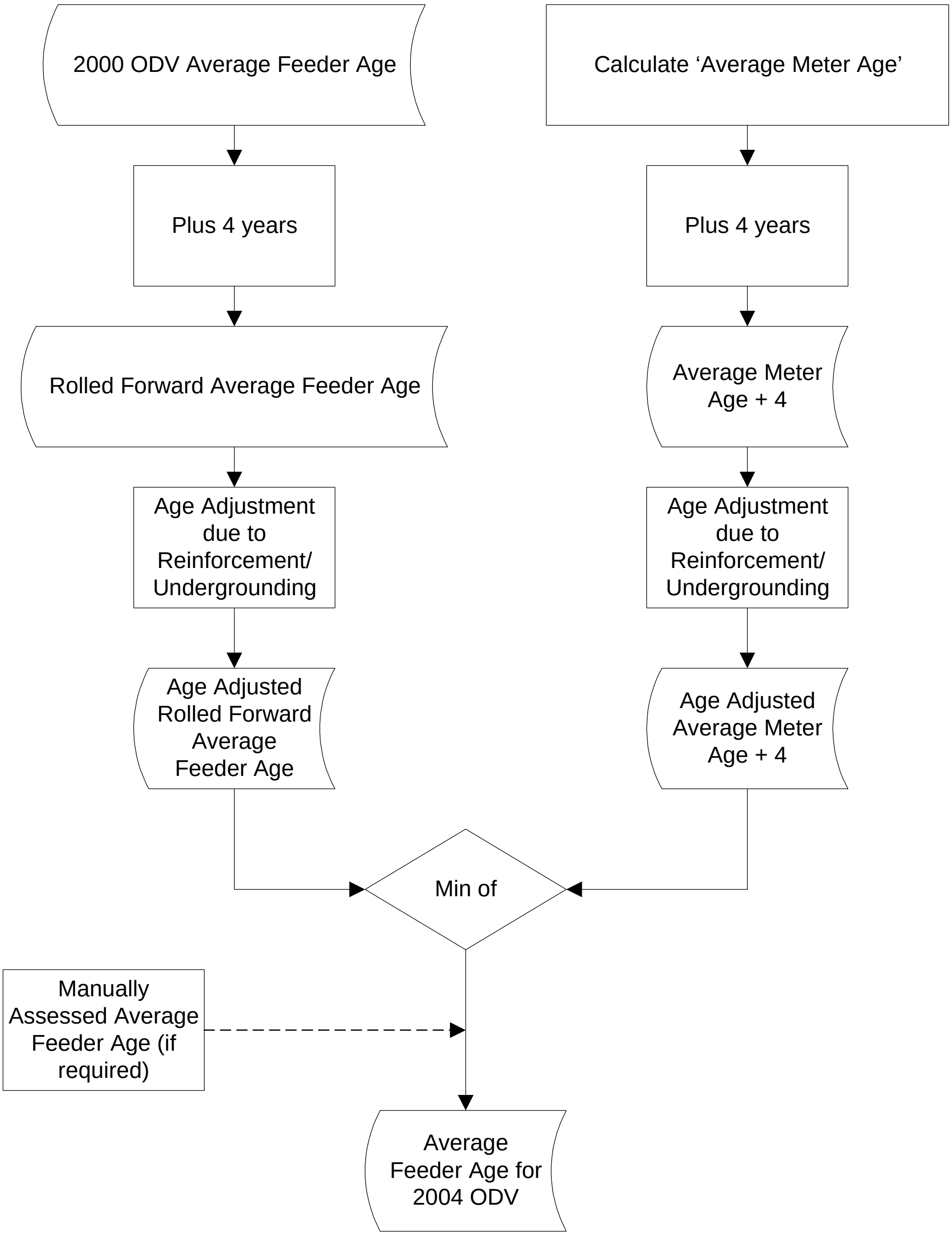
2. Calculate a rolled forward average feeder age by adding 4 years to the average feeder age used in the 2000 valuation

3. Calculate an age adjustment for the feeders where substantial reinforcement or undergrounding has occurred since the 2000 valuation. This age adjustment is applied to both the ages calculated above.

4. The average feeder age to be used for the 2004 asset valuation is the minimum of the above ages as adjusted.

5. If necessary a manually assessed age can be applied to a feeder – for example, the Albany Windfarm feeders were not in existence in 2000 and have no customer meters attached to them.

Flow Diagram



AGE ADJUSTMENT FORMULA FOR ASSESSING IMPACT OF CAPEX ON FEEDER AGE

$$ODV = \frac{\text{REMAINING AGE}}{\text{ECONOMIC LIFE}} * GODV$$

$$\therefore \quad \text{REMAINING AGE} = \frac{ODV}{GODV} * \text{ECONOMIC LIFE}$$

THE EFFECT OF CAPITAL EXPENDITURE ON AGE IS THEREFORE MEASURED BY:

$$\triangle \textbf{ REMAINING AGE} = \textbf{ECONOMIC LIFE} * \left[\frac{ODV_{NEW}}{GODV_{NEW}} - \frac{ODV_{OLD}}{GODV_{OLD}} \right]$$

WHERE:

$$GODV_{NEW} = GODV_{OLD} + CAPEX - \text{DECOMMISSIONED ASSETS}_{REPLACEMENT}$$

$$ODV_{NEW} = ODV_{OLD} + CAPEX * \left[\frac{\text{ECONOMIC LIFE – YEARS SINCE SPENT}}{\text{ECONOMIC LIFE}}\right]$$

$$- \quad \text{DECOMMISSIONED ASSETS}_{DEPRECIATED}$$

APPLICATION

$\triangle$ REMAINING AGE to be added to respective feeder remaining ages computed from the general “average meter age + 4 years” algorithm.

ASSUMPTIONS

An economic life of 41 years is assumed for both feeders and new investments. This is justified because:

- Most feeders are predominantly overhead but poles have been reinforced to give an overall economic life of something in excess of 35 years.
- Most new Capex is a mixture of asset types but will be predominantly cable, meaning that the economic life of the new asset is somewhere between 35 and 60 years.
- Consistent with 41 years used in the revenue model to depreciate Capex.

Appendix B-4 Optimisation

Transformer Optimisation

								INCLUDING ALLOWANCE FOR HV CUSTOMERS		RURAL TRANSFORMER ADJUSTMENT			PEAK FEEDER MD ADJUSTMENT						
System	Zone Substation	Quantity Sum of total	Installed Total kVA	Maximum Demand MVA Summer	Maximum Demand MVA Winter	Util % Summer	Util % Winter	customers max. demand (MVA)	Adjusted MD	10kVA units (number)	Adjusted kVA 10 to 5kVA	SCADA Peak MVA	Annual Growth %	Scaled SCADA Peak MVA	TX Overcap Util 0.4	ORC $/KVA	ORC ($)	ODRC $/kVA	ODRC ($)
SW	ALBANY	3,577	128,613	30.52	35.31	0.24	0.27	6.10	29.21	1870	119,263	40.29	1.39%	43.17	26,607	$ 84	$ 2,223,340	$ 55	$ 1,455,300
SW	AMHERST	253	80,056	55.30	40.59	0.68	0.60												
SW	ARKANA	356	90,763	65.54	48.90	0.72	0.54												
SW	AUST PAPER MILLS	260	87,291	41.07	33.30	0.47	0.38												
SW	B.P. REFINERY KWINANA	55	24,011	18.96	12.51	0.79	0.52												
SW	BEECHBORO	407	124,523	61.25	49.01	0.49	0.40												
SW	BEENUP SUBSTATION	691	18,893	6.55	5.59	0.35	0.30	-	6.55	370	17,043	6.55	1.00%	6.88	-	$ 93	$ -	$ 77	$ -
SW	BELMONT	264	88,513	64.64	44.18	0.73	0.50												
SW	BRIDGETOWN	1,259	25,088	22.20	22.60	0.88	0.90												
SW	BUNBURY HARBOUR	470	103,280	46.34	39.39	0.45	0.38												
SW	BUSSELTON	1,668	101,052	25.62	27.05	0.25	0.27	0.06	26.99	727	97,417	30.44	1.94%	33.50	13,795	$ 75	$ 1,030,409	$ 54	$ 747,189
SW	BYFORD	918	80,574	36.18	29.58	0.45	0.37												
SW	CANNING VALE	500	141,772	80.09	70.35	0.56	0.50												
SW	CAPEL	961	34,809	16.55	16.57	0.48	0.48												
SW	CHAPMAN	114	21,280	11.33	11.95	0.53	0.56												
SW	CLARENCE ST	131	51,025	30.91	27.56	0.60	0.53												
SW	COCKBURN CEMENT	396	91,079	46.95	33.01	0.52	0.37												
SW	COLLIE	539	31,824	15.92	13.79	0.50	0.43												
SW	COLLIER	143	44,820	44.20	35.27	0.99	0.79												
SW	COOK STREET	95	58,935	45.17	30.04	0.77	0.51												
SW	COOLUP	972	33,111	9.24	5.90	0.28	0.18	0.03	9.21	400	30,711	11.65	0.07%	11.69	1,558	$ 88	$ 137,568	$ 54	$ 84,463
SW	COTTESLOE	96	43,105	27.74	24.79	0.64	0.58												
SW	CUNDERDIN	1,241	25,592	8.98	6.89	0.35	0.27	2.35	6.63	888	21,152	9.31	0.00%	9.31	3,739	$ 96	$ 357,340	$ 43	$ 162,453
SW	DARLINGTON	299	25,014	17.25	18.63	0.69	0.74												
SW	DURLACHER	150	48,733	27.66	21.70	0.57	0.45												
SW	EDMUND ST	91	29,665	29.35	19.10	0.99	0.64												
SW	FORREST AVE	68	57,150	30.40	20.86	0.53	0.37												
SW	FORRESTFIELD	94	24,346	7.04	12.75	0.29	0.52												
SW	GOSNELLS	628	125,784	72.31	59.67	0.57	0.47												
SW	HADFIELDS	312	98,235	47.82	35.52	0.49	0.36												
SW	HAY ST	128	121,090	82.21	60.02	0.67	0.50												
SW	HERDSMAN PARADE	59	20,260	14.80	13.36	0.73	0.66												
SW	JOEL TERRACE	133	51,685	30.44	23.49	0.59	0.45												
SW	KALAMUNDA	408	58,716	37.54	32.48	0.64	0.55												
SW	KATANNING	2,311	45,138	12.24	13.09	0.27	0.29	0.60	12.49	1111	39,583	14.41	1.35%	15.41	2,549	$ 103	$ 261,751	$ 61	$ 154,429
SW	KELLERBERRIN	558	10,776	3.10	2.73	0.29	0.25	-	3.10	248	9,536	3.35	0.00%	3.35	1,173	$ 101	$ 118,564	$ 41	$ 48,274
SW	KOJONUP	409	5,646	2.38	2.12	0.42	0.38												
SW	KONDININ	1,754	29,209	7.81	8.39	0.27	0.29	0.00	8.39	905	24,684	9.06	0.00%	9.06	2,031	$ 117	$ 237,052	$ 55	$ 111,611
SW	LANDSDALE	270	80,866	38.44	35.62	0.48	0.44												
SW	MALAGA	123	52,133	29.47	23.04	0.57	0.44												
SW	MANDURAH	827	150,839	59.16	57.18	0.39	0.38	4.24	54.92	64	150,519	73.23	7.20%	103.68	-	$ 60	$ -	$ 43	$ -
SW	MANJIMUP	744	37,618	19.06	21.52	0.51	0.57												
SW	MANNING	132	33,525	27.95	26.24	0.83	0.78												
SW	MARGARET RIVER	1,219	45,877	8.48	8.62	0.18	0.19	-	8.62	596	42,897	9.26	5.00%	11.82	13,352	$ 83	$ 1,105,557	$ 61	$ 811,280
SW	MEDINA	443	65,963	25.48	20.71	0.39	0.31	6.07	19.41	28	65,823	34.28	1.32%	36.60	-	$ 60	$ -	$ 39	$ -
SW	MERREDIN	1,093	27,169	17.74	8.30	0.65	0.31												
SW	MIDLAND JUNCTION	440	94,581	68.69	48.58	0.73	0.51												
SW	MILLIGAN STREET	168	145,046	93.02	65.07	0.64	0.45												
SW	MOORA	2,133	36,282	12.36	12.51	0.34	0.34	-	12.51	563	33,467	12.51	0.00%	12.51	2,192	$ 117	$ 255,490	$ 50	$ 110,423
SW	MORLEY	191	48,760	42.63	32.77	0.87	0.67												
SW	MOUNT BARKER	1,067	29,826	5.12	5.49	0.17	0.18	-	5.49	1023	24,711	5.60	0.00%	5.60	10,714	$ 115	$ 1,237,395	$ 73	$ 780,685
SW	MUCHEA	1,354	62,224	14.56	10.33	0.23	0.17	2.66	11.90	498	59,734	17.83	3.35%	21.02	13,828	$ 89	$ 1,235,784	$ 58	$ 802,806
SW	MULLALOO	444	127,926	76.75	63.84	0.60	0.50												
SW	MYAREE	150	55,020	42.47	35.17	0.77	0.64												
SW	NARROGIN	2,009	42,392	12.74	11.91	0.30	0.28	-	12.74	1041	37,107	14.48	0.65%	14.96	-	$ 98	$ -	$ 58	$ -
SW	NEDLANDS	73	29,040	23.46	18.36	0.79	0.62												
SW	NORTH BCH	431	107,075	82.83	67.05	0.77	0.63												
SW	NORTH PERTH	158	62,690	38.59	29.63	0.62	0.47												
SW	NORTHAM	2,834	67,351	23.54	18.57	0.35	0.28	0.00	23.54	2496	54,871	25.89	1.00%	27.21	-	$ 89	$ -	$ 52	$ -
SW	OSBORNE PARK	202	87,045	56.15	38.16	0.64	0.43												
SW	PICCADILLY	218	64,730	33.69	31.00	0.52	0.48												
SW	PICTON	2,122	96,198	45.93	42.43	0.48	0.44												
SW	QUINNINUP	513	10,419	1.67	1.60	0.16	0.15	-	1.67	259	9,124	1.90	0.00%	1.90	4,386	$ 104	$ 458,102	$ 60	$ 262,552
SW	REGANS FORD	813	31,363	6.44	1.66	0.21	0.05	-	6.44	305	29,838	8.91	1.50%	9.60	5,830	$ 90	$ 522,812	$ 56	$ 329,199
SW	RIVERTON	341	94,327	82.05	63.01	0.87	0.67												
SW	RIVERVALE	63	21,365	15.51	11.70	0.73	0.55												
SW	ROCKINGHAM	460	128,924	63.11	58.28	0.49	0.45												
SW	SAWYERS VALLEY	762	30,123	9.40	10.38	0.31	0.34	-	10.38	352	28,363	12.46	0.50%	12.78	-	$ 93	$ -	$ 61	$ -
SW	SHENTON PARK	109	41,820	29.09	23.58	0.70	0.56												
SW	SOUTHERN CROSS	378	9,713	8.60	9.15	0.89	0.94												
SW	TATE ST	224	94,150	56.97	45.50	0.61	0.48												
SW	THREE SPRINGS	1,338	31,042	6.60	6.06	0.21	0.20	1.32	5.28	1166	25,212	7.63	1.00%	8.02	8,462	$ 93	$ 791,046	$ 40	$ 337,405
SW	WAGIN	920	15,561	4.65	5.00	0.30	0.32	-	5.00	372	13,701	5.21	0.00%	5.21	688	$ 111	$ 76,552	$ 66	$ 45,079
SW	WANNEROO	380	105,425	49.63	46.74	0.47	0.44												
SW	WELLINGTON	60	51,160	26.29	20.34	0.51	0.40												
SW	WELSHPOOL	385	141,927	79.82	64.94	0.56	0.46												
SW	WEMBLEY DOWNS	116	27,436	23.21	20.33	0.86	0.74												
SW	WEST KALGOORLIE	151	30,852	27.18	25.58	0.88	0.83												
SW	WUNDOWIE	1,015	18,722	9.53	8.50	0.51	0.45												
SW	YANCHEP	532	82,574	24.34	25.52	0.29	0.31	2.66	22.06	85	82,149	30.09	3.71%	36.10	-	$ 61	$ -	$ 42	$ -
SW	YOKINE	243	59,785	43.06	37.35	0.73	0.62												
SW	YORNUP	847	20,867	3.88	3.99	0.19	0.19	-	3.99	451	18,412	4.50	0.00%	4.50	7,163	$ 92	$ 659,009	$ 55	$ 395,174
						0.54	0.45										$ 10,707,700		$ 6,630,329
						Average tx. Utilisation													

Appendix B-5 Asset Valuation Spread Sheet

South West Interconnected Distribution Network

		RC	DRC	ORC	ODRC
Lines and Cables		**$ 2,187,414,845**	**$ 1,178,942,147**	**$ 2,187,414,845**	**$ 1,178,942,147**
HV Lines and Cables		$ 1,300,145,277	$ 658,807,884	$ 1,300,145,277	$ 658,807,884
breakdown:	11	$ 64,424,567	$ 36,963,929	$ 64,424,567	$ 36,963,929
	22	$ 852,440,740	$ 449,466,713	$ 852,440,740	$ 449,466,713
	33	$ 361,922,808	$ 159,183,656	$ 361,922,808	$ 159,183,656
	6	$ 21,357,161	$ 13,193,587	$ 21,357,161	$ 13,193,587
		$ 1,300,145,277	$ 658,807,884	$ 1,300,145,277	$ 658,807,884
LV Lines and Cables		$ 812,631,153	$ 493,620,461	$ 812,631,153	$ 493,620,461
Steel Reinforcing		$ 59,647,280	$ 15,939,000	$ 59,647,280	$ 15,939,000
Non-Building Block		$ 14,991,136	$ 10,574,803	$ 14,991,136	$ 10,574,803
Transformers		**$ 434,311,592**	**$ 259,723,102**	**$ 423,603,812**	**$ 253,084,772**
breakdown:	11	$ 53,852,553	$ 28,454,336	$ 53,852,553	$ 28,454,336
	22	$ 320,442,302	$ 199,760,803	$ 311,018,111	$ 193,681,913
	33	$ 48,228,127	$ 24,795,910	$ 46,944,539	$ 24,236,470
	6	$ 11,788,610	$ 6,712,053	$ 11,788,610	$ 6,712,053
		$ 434,311,592	$ 259,723,102	$ 423,603,812	$ 253,084,772
Switchgear		**$ 273,244,206**	**$ 117,761,633**	**$ 273,244,206**	**$ 117,761,633**
breakdown:	11	$ 47,795,414	$ 21,365,740	$ 47,795,414	$ 21,365,740
	22	$ 190,296,745	$ 82,070,924	$ 190,296,745	$ 82,070,924
	33	$ 23,022,540	$ 8,199,361	$ 23,022,540	$ 8,199,361
	6	$ 12,129,507	$ 6,125,608	$ 12,129,507	$ 6,125,608
		$ 273,244,206	$ 117,761,633	$ 273,244,206	$ 117,761,633
Streetlights		**$ 146,855,941**	**$ 78,516,601**	**$ 146,855,941**	**$ 78,516,601**
Meters		**$ 400,192,751**	**$ 162,798,411**	**$ 400,192,751**	**$ 162,798,411**
Network Total		$ 3,442,019,335	$ 1,797,741,894	$ 3,431,311,556	$ 1,791,103,565

Note: This analysis excludes assets to be entered in registers and non-system assets.

North West Interconnected Distribution Network

			RC		DRC		ORC		ODRC
Lines and Cables		$	**37,360,080**	$	**22,822,757**	$	**37,360,080**	$	**22,822,757**
HV Lines and Cables		$	24,270,449	$	15,009,870	$	24,270,449	$	15,009,870
breakdown:	11	$	8,864,948	$	5,332,660	$	8,864,948	$	5,332,660
	22	$	10,434,585	$	6,272,305	$	10,434,585	$	6,272,305
	33	$	4,970,917	$	3,404,905	$	4,970,917	$	3,404,905
	6								
		$	24,270,449	$	15,009,870	$	24,270,449	$	15,009,870
LV Lines and Cables		$	13,089,630	$	7,812,886	$	13,089,630	$	7,812,886
Steel Reinforcing									
Non-Building Block									
Transformers		$	**8,943,574**	$	**5,246,094**	$	**8,943,574**	$	**5,246,094**
breakdown:	11	$	4,279,807	$	2,388,925	$	4,279,807	$	2,388,925
	22	$	4,077,866	$	2,447,027	$	4,077,866	$	2,447,027
	33	$	585,901	$	410,141	$	585,901	$	410,141
	6								
		$	8,943,574	$	5,246,094	$	8,943,574	$	5,246,094
Switchgear		$	**5,886,103**	$	**2,230,517**	$	**5,886,103**	$	**2,230,517**
breakdown:	11	$	2,465,782	$	1,006,679	$	2,465,782	$	1,006,679
	22	$	3,224,579	$	1,110,031	$	3,224,579	$	1,110,031
	33	$	195,742	$	113,806	$	195,742	$	113,806
	6								
		$	5,886,103	$	2,230,517	$	5,886,103	$	2,230,517
Streetlights		$	**1,569,232**	$	**988,278**	$	**1,569,232**	$	**988,278**
Meters		$	**7,543,833**	$	**3,068,831**	$	**7,543,833**	$	**3,068,831**
Network Total		$	61,302,822	$	34,356,477	$	61,302,822	$	34,356,477

Note: This analysis excludes assets to be entered in registers and non-system assets.

Regional Isolated Networks

		RC	DRC	ORC	ODRC
Lines and Cables		**$ 140,346,492**	**$ 91,102,893**	**$ 140,346,492**	**$ 91,102,893**
HV Lines and Cables		$ 110,366,454	$ 71,299,306	$ 110,366,454	$ 71,299,306
breakdown:	11	$ 20,338,965	$ 13,845,079	$ 20,338,965	$ 13,845,079
	22	$ 17,009,212	$ 11,414,417	$ 17,009,212	$ 11,414,417
	33	$ 59,486,344	$ 37,258,891	$ 59,486,344	$ 37,258,891
	6	$ 13,531,933	$ 8,780,920	$ 13,531,933	$ 8,780,920
		$ 110,366,454	$ 71,299,306	$ 110,366,454	$ 71,299,306
LV Lines and Cables		$ 29,240,578	$ 19,344,955	$ 29,240,578	$ 19,344,955
Steel Reinforcing					
Non-Building Blocks		$ 739,460	$ 458,631	$ 739,460	$ 458,631
Transformers		**$ 22,275,388**	**$ 13,864,255**	**$ 22,275,388**	**$ 13,864,255**
breakdown:	11	$ 6,460,152	$ 4,069,902	$ 6,460,152	$ 4,069,902
	22	$ 4,721,769	$ 3,039,677	$ 4,721,769	$ 3,039,677
	33	$ 6,101,173	$ 3,457,307	$ 6,101,173	$ 3,457,307
	6	$ 4,992,294	$ 3,297,368	$ 4,992,294	$ 3,297,368
		$ 22,275,388	$ 13,864,255	$ 22,275,388	$ 13,864,255
Switchgear		**$ 12,032,333**	**$ 6,329,034**	**$ 12,032,333**	**$ 6,329,034**
			1,208.80		
breakdown:	11	$ 1,726,640	$ 815,995	$ 1,726,640	$ 815,995
	22	$ 4,225,648	$ 2,405,969	$ 4,225,648	$ 2,405,969
	33	$ 3,107,110	$ 1,629,567	$ 3,107,110	$ 1,629,567
	6	$ 2,972,935	$ 1,477,504	$ 2,972,935	$ 1,477,504
		$ 12,032,333	$ 6,329,034	$ 12,032,333	$ 6,329,034
Streetlights		**$ 3,309,935**	**$ 1,599,466**	**$ 3,309,935**	**$ 1,599,466**
Meters		**$ 11,210,432**	**$ 4,560,404**	**$ 11,210,432**	**$ 4,560,404**
Network Total		$ 189,174,580	$ 117,456,051	$ 189,174,580	$ 117,456,051

Note: This analysis excludes assets to be entered in registers and non-system assets.

Appendix C - Transmission Schedules

Appendix C-1 MERA Costs and Lives

TRANSFORMERS

Code	Std Cost $000	Std Life (Years)	MVA Range	Comments
na	-	50		1 year life to avoid divide by 0 error
NA	-	50		1 year life to avoid divide by 0 error
T5010	459	50	<15	22/11 20 mva
T5020	513	50	15 -30	22/11 30 mva
T6010	417	50	<15	33/22 15 mva
T6020	780	50	15 -30	33/22 30 mva
T6020Tx	587	50	15 -30	33/22 30 mva Tx Only (Strategic Spare)
T7010	656	50	<15	66/22 15 mva
T7010Tx	534	50	<15	66/22 15 mva Tx Only (Strategic Spare)
T7020	757	50	15 -30	66/22 20/27 mva
T7020Tx	587	50	15 -30	66/22 20/27 mva Tx Only (Strategic Spare)
T8010	817	50	<20	132/22 10/15 mva
T8030	892	50	20 -40	132/22 20/27/33 mva
T8030Tx	650	50	20 -40	132/22 20/27/33 mva Tx Only (Strategic Spare)
T8060	1,091	50	40 -80	132/22 60mva
T8060Tx	951	50	40 -80	132/22 60mva Tx Only (Strategic Spare)
T8100	1,731	50	80 -150	132/66/22 50/75/100 mva
T9250	3,455	50	100 -300	330/132 250mva
T9500	4,523	50	300- 600	330/132 490 mva
TX015	1,213	50	<40	220/33 27 mva
TX050	1,854	50	40 -120	220/33/22 45/60/75 mva
TX250	2,921	50	200 -300	220/132 350mva

REACTORS

Code	Std Cost $000	Std Life (Years)	Comments
na	-	50	1 year life to avoid divide by 0 error
NA	-	50	1 year life to avoid divide by 0 error
R006	331	50	Up to 6 MVAr
R012	406	50	6 to 12 MVAr
R030	513	50	12 to 30 MVAr

CAPACITORS

Code	Std Cost $000	Std Life (Years)	Comments
na	-	40	1 year life to avoid divide by 0 error
NA	-	40	1 year life to avoid divide by 0 error
C7020	605	40	66 kV 13-25 MVAr
C7055	656	40	66 kV 26-55 MVAr
C8065	1,470	40	132kV 35-70 MVAR
CD006	331	40	Up to 6 MVAr
CD012	339	40	7 to 12 MVAr
SVC	12,592	40	WKT & MRT
FILTER	604	40	all filters

Appendix C-1 MERA Costs and Lives (continued)

Code	Std Cost $000	Std Life (Years)	Comments
na	-	50	1 year life to avoid divide by 0 error
NA	-	50	1 year life to avoid divide by 0 error
B7L1	511	50	line cct, single bus
B7L0	406	50	line cct, single bus, no ocb
B7T2	606	50	tx cct, double bus
B7TB	410	50	tx cct & bus coupler (only a few)
B7T1	404	50	tx cct, single bus
B7T0	406	50	tx cct, single bus no ocb
B7BC	410	50	bus coupler
B7L2	606	50	line cct, double bus
B700	106	50	cct, no ocb
B8H0	729	50	breaker & half, no ocb, 2 gantry, 1 cct
B8H1	950	50	breaker & half, 1 ocb, 2 gantry, 1 cct
B8H2	1,438	50	breaker & half, 2 ocb, 3 gantry, 1cct
B8H3	2,026	50	breaker & half, 3 ocb, 3 gantry 2 cct
B8L1	669	50	line cct, single bus
B8L0	477	50	line cct, single bus, no ocb
B8T2	748	50	tx cct, double bus
B8TB	458	50	tx cct & bus coupler (only a few)
B8T1	491	50	tx cct, single bus
B8T0	477	50	tx cct, single bus no ocb
B8BC	458	50	bus coupler
B8L2	748	50	line cct, double bus
B800	118	50	cct, no ocb
B9H0	1,271	50	breaker & half, no ocb, 2 gantry, 1 cct
B9H1	1,809	50	breaker & half, 1 ocb, 2 gantry, 1 cct
B9H2	2,918	50	breaker & half, 2 ocb, 3 gantry, 1cct
B9H3	3,997	50	breaker & half, 3 ocb, 3 gantry 2 cct
BDSI	103	50	single bus indoor
BDSO	171	50	single bus outdoor
BD0O	139	50	no ocb, outdoor, combined lv tx/feeder cct
BDDI	110	50	double bus indoor
BDDO	188	50	double bus outdoor
BDRO	94	50	recloser, outdoor
BXH0	1,172	50	breaker & half, no ocb, 2 gantry, 1 cct
BXH1	1,338	50	breaker & half, 1 ocb, 2 gantry, 1 cct
BXH2	2,033	50	breaker & half, 2 ocb, 3 gantry, 1cct
BXH3	2,757	50	breaker & half, 3 ocb, 3 gantry 2 cct
BXL1	1,247	50	line cct, single bus
BXT1	1,247	50	Tx cct, single bus
BD00	139	50	no ocb, outdoor, cct

SITE

Code	Std Cost $000	Std Life (Years)	Comments
na	-	50	1 year life to avoid divide by 0 error
NA	-	50	1 year life to avoid divide by 0 error
DS	-	50	Used when a site is deleted when optimised
SLI	3,778	50	Milligan & Hay Streets
SLO	1,988	50	Terminal Station, 1 yard, 1 relay room
DLO	3,977	50	Terminal Station, 2 yards, 2 relay rooms
TLO	5,965	50	Terminal Station, 3 yards, 3 relay rooms
SSO	757	50	Substation
OTH	-	50	Other - none of the above
RRT	-	50	Rapid Response & Spare Tx

Appendix C-1 MERA Costs and Lives (continued)

Conductor Section Costs			
MEAID	**MERA code**	**Std Cost as at Jun 04 $000**	**Std Life (Years)**
6 LATT SC 300	6 ST 300	68.155	60
6 TUBU DC 300	6 ST 300	68.155	60
6 TUBU DZ 400	6 ST 300	68.155	60
6 TUBU SC 200	6 ST 300	68.155	60
6 TUBU SC 300	6 ST 300	68.155	60
6 TUBU DZ 300	6 ST 300	68.155	60
6 WOOD DC 300	6 ST 300	68.155	60
6 WOOD DZ 300	6 ST 300	68.155	60
6 WOOD SC 300	6 ST 300	68.155	60
6 WOOD SC 400	6 ST 300	68.155	60
7 LATT DC 300	7 SL 300	96.283	60
7 LATT DC 400	7 SL 300	96.283	60
7 LATT DZ 400	7 SL 300	96.283	60
7 LATT SC 200	7 SL 300	96.283	60
7 LATT SC 300	7 SL 300	96.283	60
7 LATT SC 400	7 SL 300	96.283	60
7 TUBU DC 300	7 ST 300	73.564	60
7 TUBU DC 400	7 ST 400	81.137	60
7 TUBU SC 200	7 ST 200	63.828	60
7 TUBU SC 300	7 ST 300	73.564	60
7 TUBU SC 400	7 ST 400	81.137	60
7 WOOD SC 200	7 SW 200	57.337	45
7 WOOD SC 300	7 SW 300	63.828	45
7 WOOD SC 400	7 SW 400	72.482	45
7 WOOD SC 750	7 SW 400	72.482	45
8 LATT DC 1000	8 DL 1000	137.392	60
8 LATT DC 300	8 DL 300	75.728	60
8 LATT DC 400	8 DL 400	83.301	60
8 LATT DC 550	8 DL 550	95.201	60
8 LATT DC 750	8 DL 750	120.083	60
8 LATT DZ 1000	8 SL 1000	177.420	60
8 LATT DZ 400	8 SL 400	115.756	60
8 LATT DZ 550	8 SL 550	128.738	60
8 LATT DZ 750	8 SL 750	157.947	60
8 LATT SC 1000	8 SL 1000	177.420	60
8 LATT SC 200	8 SL 200	97.365	60
8 LATT SC 300	8 SL 300	107.101	60
8 LATT SC 400	8 SL 400	115.756	60
8 LATT SC 550	8 SL 550	128.738	60
8 LATT SC 750	8 SL 750	157.947	60
8 TUBU DC 300	8 DT 300	162.274	60

Appendix C-1 MERA Costs and Lives (continued)

Conductor Section Costs			
MEAID	MERA code	Std Cost as at Jun 04 $000	Std Life (Years)
8 TUBU DC 400	8 DT 400	189.320	60
8 TUBU DC 750	8 DT 750	216.366	60
8 TUBU DZ 1000	8 SL 1000	177.420	60
8 TUBU DZ 400	8 ST 400	98.446	60
8 TUBU DZ 750	8 SL 750	157.947	60
8 TUBU SC 1000	8 SL 1000	177.420	60
8 TUBU SC 200	8 ST 200	83.301	60
8 TUBU SC 300	8 ST 300	90.874	60
8 TUBU SC 400	8 ST 400	98.446	60
8 TUBU SC 550	8 ST 400	98.446	60
8 TUBU SC 750	8 ST 400	98.446	60
8 WOOD DC 400	8 SW 400	104.937	45
8 WOOD DC 550	8 SW 550	128.738	45
8 WOOD DC 750	8 SW 550	128.738	45
8 WOOD DZ 400	8 SW 400	104.937	45
8 WOOD DZ 550	8 SW 550	128.738	45
8 WOOD DZ 750	8 SW 550	128.738	45
8 WOOD SC 1000	8 SW 550	128.738	45
8 WOOD SC 200	8 SW 200	60.582	45
8 WOOD SC 300	8 SW 300	82.219	45
8 WOOD SC 400	8 SW 400	104.937	45
8 WOOD SC 550	8 SW 550	128.738	45
8 WOOD SC 750	8 SW 550	128.738	45
9 LATT DC 1000	9 DL 1000	170.929	60
9 LATT DC 400	9 DT 750	153.620	60
9 LATT DC 750	9 DL 750	153.620	60
9 LATT DZ 1000	9 DZ 1000	257.475	60
9 LATT DZ 750	9 DZ 750	230.429	60
9 LATT SC 1000	9 SL 1000	209.875	60
9 LATT SC 400	X SL 400	128.738	60
9 LATT SC 750	9 SL 750	191.484	60
9 TUBU DC 1000	9 DT 750	153.620	60
9 TUBU DC 750	9 DT 750	153.620	60
9 TUBU DZ 1000	9 DZ 1000	257.475	60
9 TUBU DZ 750	9 DZ 750	230.429	60
9 TUBU SC 1000	9 SL 1000	209.875	60
9 TUBU SC 750	9 SL 750	191.484	60
na	na	-	60
X LATT SC 1000	X SL 400	128.738	60
X LATT SC 300	X SL 300	122.247	60
X LATT SC 400	X SL 400	128.738	60
X LATT SC 550	X SL 400	128.738	60
X TUBU SC 1000	X SL 400	128.738	60
X TUBU SC 300	X SL 300	122.247	60
X TUBU SC 400	X SL 400	128.738	60
X TUBU SC 550	X SL 400	128.738	60

		-	
	OPT	-	60
		-	

installed circuit cost per km - based upon flat, rural, low wind of 100km

Appendix C-1 MERA Costs and Lives (continued)

Cable MERAs

MEAID	MERA code	Unit replacement inc idc	Std economic life
7 UNDG 300	7 UG 300	**750**	55
7 UNDG 600	7 UG 600	**775**	55
8 UNDG 300	8 UG 300	**1000**	55
8 UNDG 600	8 UG 600	**1075**	55
8 UNDG 1200	8 UG 1200	**1150**	55

installed cost per 1km of cable - based on 1 km in metro area

In aligning identified modern equivalent assets ("MEAID") with a MERA code for valuation purposes, we have been mindful of the quantum of assets within each MEAID grouping and the aggregate DORC value for that grouping. Immaterial MEAID groupings have been allocated a MERA code for valuation purposes which approximates that of the MEAID asset group. No material valuation impact arises as a consequence of classification of minor MEAID groupings to more general MERA codes.

Appendix C-2 Adjustment Factors

Unit Cost Multipliers for Overhead Lines

Length Multipliers

0-5km	2.50
5-20km	1.90
20-50km	1.50
51-75km	1.20
75-100km	1.05
101-150km	1.00
Over 150km	0.95

Route Multipliers

Wind Loading

Region A	South West up to Eneabba	1.00
Region B	Geraldton area	1.04
Region C	North West Inland (cyclonic)	1.26
Region D	North West Coastal (cyclonic)	1.45

Terrain

Flat	1.00
Coastal	1.02
Rolling	1.02
Hilly	1.12

Angles

(0.25 x 2.5 x (r - 1))
where r = ratio of angles and terminations to the total number of structures

Foundations

Generally	1.00
Coastal Plain (sand or wet)	1.07 (lattice and tubular steel poles only)

Unit Cost Multipliers for Substations

Remoteness

North West	1.16
South West	
- General	1.00
- Bunbury	1.05
- East Country	1.05
- Eastern Goldfields	1.10
- Muja	1.05
- North Country	1.10

Appendix C-3 Ageing Formula (for new capital expenditure)

These proportions are used to calculate a hypothetical age for a circuit bay (for valuation purposes) based on the different ages of the components within that bay. The proportions used for each component were agreed with Sinclair Knight Merz.
NB These proportions do not have to add up to one for every bay. The worksheet normalises the proportions to the total for each circuit hence the proportions are required to be relative only.

Symbol	Proportion	Number per Unit	Proportion/Unit		
CB	0.25	1	0.25		
CBC	0.5	1	0.5		
CT	0.25	3	0.083333333		
VT	0.1	3	0.033333333		
CVT	0.1	3	0.033333333		
CCV	0.35	3	0.116666667		
DIS	0.25	3	0.083333333		
DES	0.35	3	0.116666667		
ES	0.1	3	0.033333333		
LT	0.001	3	0.000333333		
SA	0.05	3	0.016666667		

Appendix C-4 Optimisation – Kalgoorlie Line

	Incremental Costs of Supplying Energy with and without GTs at Kalgoorlie				
Real Pre Tax WACC				7.20%	
Actual Energy Transfer YLN-WKT in 2003 (MWhr)				552,426	
Percentage Growth expected in Kalgoorlie				3%	
Projected Required Energy Transfer YLN-WKT in 2019 (MWhr)				860,662	
Average Required Energy Transfer YLN-WKT 2004-19 (MWhr)				706,544	
Energy ex Muja $/MWh				$57.10	
Substation Life (years)				50	
Lines Life (years)				60	
GT Life (years)				25	
OPTION A _ Muja-Merredin-Kalgoorlie (No Additional Generation at Kalgoorlie)					
Capital	ORC		$k	Life	Equivalent Annual Annuity
	MU-WKT Substations @ 220kV		103,958	50	7,724
	MU-WKT Lines @ 220kV		83,086	60	6,076
			187,044		13,800
Operating					
	1%	Maintenance	1,642		
		Energy ex Muja $/MWh	40,344		
	2%	Line Losses etc.	807		
			42,792		42,792
Total (Including ROI) (Option A)					56,592
OPTION B - 2 New GTs at Kalgorlie and MU-YLN Line optimised to 132kV with YLN-WKT deleted					
Capital	ORC		$k	Life	Equivalent Annual Annuity
	MU-YLN Substations @ 132kV		18,291	50	1,359
	MU-YLN Lines @ 132kV		51,889	60	3,795
	Cost to upgrade Parkeston interconnector		6,000	60	439
Kalgoorlie	New GTs	2 off LM6000 + SUT	62,000	25	5,416
			138,180		11,009
Operating					
MU-YLN	1%	Maintenance	702		
		Energy ex Muja $/MWh	-		
New GTs	0.6	c / kwhr GT O&M			
	31%	GT Average Efficiency			
	$4.75	Cost of Gas / GJ			
	$61.16	Cost of Generation / MWhr	43,210		
	0.55%	SUT Losses	238		
			43,912		43,912
Total (Including ROI) [Option B]					$54,920.59
OPTION C - Economically Optimise 220kV Lines so ROI of Option B and Option C is equal					
Capital	ORC		Optimised	Life	Equivalent Annual Annuity
	Substations		103,958	50	$7,723.77
	Line		**60,229**	60	$4,404.42
			164,186		12,128
Operating	as above				42,792
Total (Including ROI) (Option C)					54,921
Excel 'Goal Seek' to Find Required Written Down Value					
Difference between Option B and Option C					-
Required Write Down of Lines (as per Option C)					**22,857**
Value of YLN-WKT 220kV Line					25,377
Write YLN-WKT down to x% of value					9.93%

Appendix C-5 Summary of Asset Values

Substations – SWIS

Sub	Region	RC	DRC	ORC	ODRC	GODV	ODV
A	SWIS	9,451	4,592	8,707	4,239	8,707	4,239
ALB	SWIS	11,963	6,544	10,901	5,975	10,901	5,975
AMT	SWIS	7,249	6,854	6,303	5,957	6,303	5,957
APM	SWIS	5,806	1,881	5,265	1,622	5,265	1,622
BCH	SWIS	8,611	5,641	7,935	5,178	7,935	5,178
BDE	SWIS	1,909	1,651	1,909	1,651	1,909	1,651
BEL	SWIS	8,451	6,185	8,451	6,185	8,451	6,185
BKF	SWIS	6,738	5,005	6,367	4,760	6,367	4,760
BLD	SWIS	13,095	8,057	12,351	7,601	12,351	7,601
BNP	SWIS	3,365	2,817	3,216	2,697	3,216	2,697
BNY	SWIS	2,631	2,034	2,631	2,034	2,631	2,034
BOD	SWIS	6,723	4,200	6,652	4,155	6,652	4,155
BP	SWIS	5,615	1,408	5,615	1,408	5,615	1,408
BSN	SWIS	12,128	4,177	11,631	3,949	11,631	3,949
BTN	SWIS	5,274	3,947	4,848	3,592	4,848	3,592
BUH	SWIS	8,746	4,671	8,107	4,371	8,107	4,371
BYF	SWIS	6,055	2,288	5,581	2,098	5,581	2,098
C	SWIS	8,067	1,990	8,067	1,990	8,067	1,990
CAP	SWIS	7,498	3,193	7,072	3,024	7,072	3,024
CAR	SWIS	2,826	1,939	2,826	1,939	2,826	1,939
CC	SWIS	7,872	3,844	7,264	3,576	7,264	3,576
CK	SWIS	8,761	6,478	8,761	6,478	8,761	6,478
CL	SWIS	5,863	2,176	5,863	2,176	5,863	2,176
CLP	SWIS	4,636	1,825	4,210	1,551	4,210	1,551
CO	SWIS	7,272	2,419	6,633	2,206	6,633	2,206
COL	SWIS	7,242	2,482	7,242	2,482	7,242	2,482
CPN	SWIS	4,779	2,755	4,779	2,755	4,779	2,755
CT	SWIS	32,208	17,295	32,208	17,295	32,208	17,295
CTB	SWIS	2,199	1,555	2,199	1,555	2,199	1,555
CUN	SWIS	5,478	2,445	4,533	2,070	4,533	2,070
CVE	SWIS	11,196	6,975	10,048	6,141	10,048	6,141
D	SWIS	6,232	2,467	5,894	2,328	5,894	2,328
DUR	SWIS	4,975	2,497	4,975	2,497	4,975	2,497
E	SWIS	7,411	4,100	7,411	4,100	7,411	4,100
ENB	SWIS	7,221	3,574	6,795	3,366	6,795	3,366
EP	SWIS	22,321	8,283	22,321	8,283	22,321	8,283
F	SWIS	4,252	1,611	4,252	1,611	4,252	1,611
FFD	SWIS	3,993	2,984	3,993	2,984	3,993	2,984
G	SWIS	9,117	3,736	8,509	3,467	8,509	3,467
GTN	SWIS	12,620	6,479	11,313	5,844	11,313	5,844
H	SWIS	8,451	4,797	8,451	4,797	8,451	4,797
HAY	SWIS	16,622	9,005	16,622	9,005	16,622	9,005
HE	SWIS	5,444	1,729	5,444	1,729	5,444	1,729
JT	SWIS	5,536	1,028	5,536	1,028	5,536	1,028

Appendix C-5 Summary of Asset Values (continued)

Substations – SWIS (continued)

K	SWIS	6,393	2,426	5,920	2,257	5,920	2,257
KAT	SWIS	6,727	2,289	5,764	1,801	5,764	1,801
KDN	SWIS	10,916	6,683	9,747	6,272	9,747	6,272
KEL	SWIS	5,179	1,936	4,315	1,353	4,315	1,353
KEM	SWIS	9,948	6,291	9,948	6,291	9,948	6,291
KMK	SWIS	1,917	1,696	1,917	1,696	1,917	1,696
KOJ	SWIS	11,079	5,623	10,716	5,441	10,716	5,441
KW	SWIS	26,919	14,974	26,919	14,974	26,919	14,974
LDE	SWIS	6,612	5,841	6,612	5,841	6,612	5,841
MA	SWIS	5,740	2,758	5,740	2,758	5,740	2,758
MBR	SWIS	3,815	2,818	3,744	2,756	3,744	2,756
MC	SWIS	6,490	2,236	6,490	2,236	6,490	2,236
MED	SWIS	5,884	3,085	5,478	2,848	5,478	2,848
MER	SWIS	9,951	5,876	9,379	5,377	9,379	5,377
MGA	SWIS	10,426	7,450	10,426	7,450	10,426	7,450
MH	SWIS	8,280	5,330	7,604	4,861	7,604	4,861
MIL	SWIS	17,064	8,394	17,064	8,394	17,064	8,394
MJ	SWIS	8,798	4,527	8,054	4,257	8,054	4,257
MJP	SWIS	7,722	3,280	7,225	3,080	7,225	3,080
MLA	SWIS	5,228	2,425	5,228	2,425	5,228	2,425
MLG	SWIS	1,269	1,154	1,066	970	1,066	970
MO	SWIS	7,571	3,149	6,731	2,576	6,731	2,576
MOR	SWIS	6,906	2,592	6,268	2,317	6,268	2,317
MR	SWIS	5,369	4,247	5,227	4,122	5,227	4,122
MRR	SWIS	5,235	3,092	5,164	3,037	5,164	3,037
MRT	SWIS	40,566	22,585	40,566	22,585	40,566	22,585
MSR	SWIS	8,670	6,214	8,670	6,214	8,670	6,214
MU	SWIS	61,899	33,188	61,899	33,188	61,899	33,188
MUC	SWIS	8,199	4,060	7,793	3,886	7,793	3,886
MUL	SWIS	10,531	5,602	9,788	5,154	9,788	5,154
MW	SWIS	4,662	1,976	4,527	1,923	4,527	1,923
MYR	SWIS	6,000	2,532	6,000	2,532	6,000	2,532
N	SWIS	7,983	3,251	7,983	3,251	7,983	3,251
NB	SWIS	9,808	4,467	8,929	3,916	8,929	3,916
NF	SWIS	6,043	1,397	6,043	1,397	6,043	1,397
NGN	SWIS	6,505	1,672	5,653	1,423	5,653	1,423
NGS	SWIS	7,337	3,646	6,800	3,346	6,800	3,346
NOR	SWIS	15,180	7,682	14,199	7,028	14,199	7,028
NP	SWIS	7,253	5,937	7,253	5,937	7,253	5,937
NT	SWIS	41,323	24,727	41,323	24,727	41,323	24,727

Appendix C-5 Summary of Asset Values (continued)

Substations – SWIS (continued)

OC	SWIS	8,483	3,225	8,483	3,225	8,483	3,225
OP	SWIS	9,011	3,582	9,011	3,582	9,011	3,582
PCY	SWIS	8,294	4,627	8,294	4,627	8,294	4,627
PIC	SWIS	19,359	10,268	18,721	9,981	18,721	9,981
PJR	SWIS	15,456	11,258	15,456	11,258	15,456	11,258
PNJ	SWIS	5,156	3,302	5,085	3,247	5,085	3,247
QNP	SWIS	3,854	3,072	3,641	2,882	3,641	2,882
RGN	SWIS	7,813	6,885	7,317	6,445	7,317	6,445
RO	SWIS	9,952	6,294	9,141	5,749	9,141	5,749
RRT	SWIS	3,297	2,743	3,297	2,743	3,297	2,743
RTN	SWIS	8,952	5,724	8,141	5,143	8,141	5,143
RV	SWIS	6,153	1,963	6,153	1,963	6,153	1,963
SF	SWIS	20,825	10,063	20,825	10,063	20,825	10,063
SHO	SWIS	7,620	6,592	7,620	6,592	7,620	6,592
SP	SWIS	8,596	2,946	8,596	2,946	8,596	2,946
ST	SWIS	35,942	18,917	35,942	18,917	35,942	18,917
SV	SWIS	4,451	1,071	4,309	1,028	4,309	1,028
SX	SWIS	5,423	1,896	1,775	538	1,775	538
TS	SWIS	9,807	3,818	9,153	3,578	9,153	3,578
TT	SWIS	7,817	2,867	7,074	2,565	7,074	2,565
U	SWIS	5,334	1,526	5,334	1,526	5,334	1,526
VP	SWIS	6,119	1,069	6,119	1,069	6,119	1,069
W	SWIS	4,878	3,524	4,878	3,524	4,878	3,524
WAG	SWIS	5,612	838	4,325	622	4,325	622
WCL	SWIS	2,199	1,831	2,199	1,831	2,199	1,831
WD	SWIS	7,273	2,823	7,273	2,823	7,273	2,823
WE	SWIS	9,775	6,577	9,031	6,098	9,031	6,098
WGP	SWIS	5,999	3,313	5,644	3,134	5,644	3,134
WKT	SWIS	48,530	28,682	48,530	28,682	48,530	28,682
WM	SWIS	2,095	1,107	2,095	1,107	2,095	1,107
WNO	SWIS	7,789	6,811	7,789	6,811	7,789	6,811
WOR	SWIS	3,838	2,837	3,838	2,837	3,838	2,837
WT	SWIS	20,544	8,898	20,544	8,898	20,544	8,898
WUN	SWIS	5,478	1,010	4,906	887	4,906	887
Y	SWIS	7,791	2,673	6,857	2,428	6,857	2,428
YER	SWIS	3,024	840	3,024	840	3,024	840
YLN	SWIS	10,225	5,921	9,728	5,581	9,728	5,581
YNP	SWIS	7,562	2,228	6,519	1,991	6,519	1,991
YP	SWIS	7,287	3,673	6,814	3,439	6,814	3,439
XOS	#N/A	6,202	1,938	6,202	1,938	6,202	1,938
Total SWIS		**1,181,115**	**619,954**	**1,139,554**	**598,781**	**1,139,554**	**598,781**

Appendix C-5 Summary of Asset Values (continued)

Substations – NWIS

Sub	Region	RC	DRC	ORC	ODRC	GODV	ODV
AST	NWIS	9,471	3,884	8,844	3,684	8,844	3,684
BUL	NWIS	8,187	3,912	7,481	3,655	7,481	3,655
CLB	NWIS	10,735	5,471	10,108	5,173	10,108	5,173
DMP	NWIS	3,703	1,881	3,311	1,718	3,311	1,718
HDT	NWIS	14,836	8,264	14,757	8,227	14,757	8,227
KRT	NWIS	6,605	3,836	6,605	3,836	6,605	3,836
MDR	NWIS	8,863	4,594	8,157	4,330	8,157	4,330
MNM	NWIS	3,006	812	3,006	812	3,006	812
PCK	NWIS	8,001	4,241	7,217	3,909	7,217	3,909
ROE	NWIS	3,320	1,726	2,928	1,551	2,928	1,551
WCT	NWIS	1,076	623	998	588	998	588
WFD	NWIS	8,900	4,282	8,429	4,139	8,429	4,139
Total NWIS		**86,702**	**43,526**	**81,841**	**41,625**	**81,841**	**41,625**

Sub	Region	RC	DRC	ORC	ODRC	GODV	ODV
AST	NWIS	9,471	3,884	8,844	3,684	8,844	3,684
BUL	NWIS	8,187	3,912	7,481	3,655	7,481	3,655
CLB	NWIS	10,735	5,471	10,108	5,173	10,108	5,173
DMP	NWIS	3,703	1,881	3,311	1,718	3,311	1,718
HDT	NWIS	14,836	8,264	14,757	8,227	14,757	8,227
KRT	NWIS	6,605	3,836	6,605	3,836	6,605	3,836
MDR	NWIS	8,863	4,594	8,157	4,330	8,157	4,330
MNM	NWIS	3,006	812	3,006	812	3,006	812
PCK	NWIS	8,001	4,241	7,217	3,909	7,217	3,909
ROE	NWIS	3,320	1,726	2,928	1,551	2,928	1,551
WCT	NWIS	1,076	623	998	588	998	588
WFD	NWIS	8,900	4,282	8,429	4,139	8,429	4,139
Total NWIS		**86,702**	**43,526**	**81,841**	**41,625**	**81,841**	**41,625**

Appendix C-5 Summary of Asset Values (continued)

SWIS Transmission Lines and Cables

New MERA	*Length*	*RC*	*DRC*	*ORC*	*ODRC*	*GODV*	*ODV*
6 TUBU DC 300	0.070	12.279	9.313	12.279	9.313	12.279	9.313
6 TUBU SC 300	2.194	383.701	290.019	383.701	290.019	383.701	290.019
6 WOOD DC 300	-	-	-	-	-	-	-
6 WOOD SC 300	8.333	1,244.346	594.788	1,244.346	594.788	1,244.346	594.788
6 WOOD SC 400	6.099	1,072.020	1,036.310	1,072.020	1,036.310	1,072.020	1,036.310
7 LATT DC 300	12.939	2,542.203	1,250.105	2,542.203	1,250.105	2,542.203	1,250.105
7 LATT SC 200	0.032	8.582	2.218	8.582	2.218	8.582	2.218
7 LATT SC 300	0.415	81.224	41.083	81.224	41.083	81.224	41.083
7 LATT SC 400	1.593	423.333	251.160	423.333	251.160	423.333	251.160
7 TUBU DC 400	6.861	1,270.267	903.441	1,270.267	903.441	1,270.267	903.441
7 TUBU SC 200	1.093	147.560	125.819	147.560	125.819	147.560	125.819
7 TUBU SC 300	12.077	1,513.580	984.211	1,513.580	984.211	1,513.580	984.211
7 TUBU SC 400	2.142	441.499	189.016	441.499	189.016	441.499	189.016
7 UNDG 300	7.693	5,769.750	1,104.666	5,769.750	1,104.666	5,769.750	1,104.666
7 UNDG 600	4.284	3,320.163	2,347.527	3,320.163	2,347.527	3,320.163	2,347.527
7 WOOD SC 200	732.649	52,847.552	17,921.487	48,694.460	17,460.033	48,694.460	17,460.033
7 WOOD SC 300	255.588	28,367.535	8,633.992	28,367.535	8,633.992	28,367.535	8,633.992
7 WOOD SC 400	29.673	4,757.957	1,221.211	4,757.957	1,221.211	4,757.957	1,221.211
7 WOOD SC 750	0.093	18.158	12.309	18.158	12.309	18.158	12.309
8 LATT DC 300	47.591	3,964.088	3,333.997	3,964.088	3,333.997	3,964.088	3,333.997
8 LATT DC 400	357.704	30,335.290	29,961.385	30,335.290	29,961.385	30,335.290	29,961.385
8 LATT SC 1000	2.536	983.821	437.384	983.821	437.384	983.821	437.384
8 LATT SC 200	89.040	9,556.481	8,203.355	9,556.481	8,203.355	9,556.481	8,203.355
8 LATT SC 300	153.041	17,633.284	12,957.362	17,633.284	12,957.362	17,633.284	12,957.362
8 LATT SC 400	27.129	5,839.387	710.145	5,838.222	709.828	5,838.222	709.828
8 LATT SC 550	11.244	2,607.030	441.591	2,607.030	441.591	2,607.030	441.591
8 LATT SC 750	40.177	12,996.195	5,026.415	12,996.195	5,026.415	12,996.195	5,026.415
8 TUBU DC 300	3.920	939.432	667.221	939.432	667.221	939.432	667.221
8 TUBU DC 400	97.972	30,226.346	22,004.741	27,474.801	20,041.198	27,474.801	20,041.198
8 TUBU DC 750	11.385	4,975.492	4,844.493	4,975.492	4,844.493	4,975.492	4,844.493
8 TUBU DZ 1000	0.096	34.642	15.303	34.642	15.303	34.642	15.303
8 TUBU SC 1000	0.380	195.431	125.230	195.431	125.230	195.431	125.230
8 TUBU SC 200	395.819	31,589.858	26,563.092	31,589.858	26,563.092	31,589.858	26,563.092
8 TUBU SC 300	298.259	37,106.066	28,692.620	24,948.773	20,282.647	24,948.773	20,282.647
8 TUBU SC 400	64.917	11,370.698	9,687.040	11,369.742	9,686.363	11,369.742	9,686.363
8 TUBU SC 550	1.184	290.694	185.374	290.694	185.374	290.694	185.374
8 TUBU SC 750	4.219	819.580	627.622	819.580	627.622	819.580	627.622
8 UNDG 1200	3.884	4,466.874	3,972.119	4,466.874	3,972.119	4,466.874	3,972.119
8 UNDG 300	1.588	1,588.000	1,142.796	1,588.000	1,142.796	1,588.000	1,142.796
8 UNDG 600	3.585	3,853.875	2,080.806	3,853.875	2,080.806	3,853.875	2,080.806
8 WOOD DC 400	0.180	50.719	16.349	50.719	16.349	50.719	16.349
8 WOOD DC 750	1.219	306.068	295.324	306.068	295.324	306.068	295.324
8 WOOD SC 1000	0.232	60.748	15.531	60.748	15.531	60.748	15.531
8 WOOD SC 200	484.646	30,089.688	17,310.950	30,089.688	17,310.950	30,089.688	17,310.950
8 WOOD SC 300	2,019.851	198,260.502	78,813.023	198,189.726	78,771.334	198,189.726	78,771.334
8 WOOD SC 400	316.940	64,170.517	24,999.875	64,168.020	24,999.292	64,168.020	24,999.292
8 WOOD SC 550	1.707	358.284	46.593	358.284	46.593	358.284	46.593
8 WOOD SC 750	3.849	1,217.719	962.817	1,217.719	962.817	1,217.719	962.817
9 LATT DC 1000	232.177	53,672.876	32,801.626	49,604.203	29,715.822	49,604.203	29,715.822
9 LATT DC 750	1.300	428.907	306.296	397.491	282.469	397.491	282.469
9 LATT DZ 1000	235.054	69,435.292	39,682.265	69,435.292	39,682.265	69,435.292	39,682.265
9 LATT DZ 750	19.091	4,435.148	2,698.529	4,435.148	2,698.529	4,435.148	2,698.529
9 LATT SC 1000	53.184	14,563.533	10,434.518	14,563.533	10,434.518	14,563.533	10,434.518
9 LATT SC 400	0.079	27.439	24.469	27.439	24.469	27.439	24.469
9 LATT SC 750	347.920	71,139.603	43,355.257	71,127.132	43,345.798	71,127.132	43,345.798
9 TUBU DZ 1000	0.092	23.356	19.660	23.356	19.660	23.356	19.660
9 TUBU SC 750	2.676	817.949	620.331	433.032	328.398	433.032	328.398
X LATT SC 1000	0.286	37.038	24.334	37.038	24.334	37.038	24.334
X LATT SC 400	653.491	82,910.906	54,461.494	82,910.906	54,461.494	60,053.323	39,411.890
X LATT SC 550	1.044	134.729	88.707	134.729	88.707	134.729	88.707
X TUBU SC 1000	-	-	-	-	-	-	-
X TUBU SC 400	0.029	3.743	2.724	3.743	2.724	3.743	2.724
Total		**907,739.0**	**505,579.4**	**884,104.2**	**491,290.2**	**861,246.7**	**476,240.6**

Appendix C-5 Summary of Asset Values (continued)

NWIS Transmission Lines

New MERA	Length	RC	DRC	ORC	ODRC	GODV	ODV
6 TUBU SC 300	21.369	3,331.533	2,249.146	3,331.533	2,249.146	3,331.533	2,249.146
7 LATT SC 300	95.273	14,194.181	10,528.890	14,194.181	10,528.890	14,194.181	10,528.890
7 LATT SC 400	3.600	536.343	397.846	536.343	397.846	536.343	397.846
7 TUBU SC 300	49.327	7,897.768	4,670.647	7,897.768	4,670.647	7,897.768	4,670.647
8 LATT SC 300	41.250	8,808.406	5,652.814	8,808.406	5,652.814	8,808.406	5,652.814
8 TUBU SC 300	33.178	7,704.777	4,233.774	7,704.777	4,233.774	7,704.777	4,233.774
8 WOOD SC 300	2.500	593.518	257.259	593.518	257.259	593.518	257.259
X LATT SC 300	191.354	33,102.791	21,795.125	33,102.791	21,795.125	33,102.791	21,795.125
X LATT SC 400	5.300	965.545	635.722	965.545	635.722	965.545	635.722
X TUBU SC 300	0.015	2.595	1.708	2.595	1.708	2.595	1.708
Total		**77,137.5**	**50,422.9**	**77,137.5**	**50,422.9**	**77,137.5**	**50,422.9**