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20 December 2011

## *Submission to the Distribution Network Planning and Expansion Framework Rule change proposal*

Mr. John Pierce
Chairman
Australian Energy Market Commission
Level 5, 201 Elizabeth Street
Sydney NSW 2000
Email: submissions@aemc.gov.au

Dear Mr. Pierce,

The Copper Development Centre (CDC) welcomes the opportunity to provide this contribution and suggests a minor modification to the AEMC's proposed Rule change on the Distribution Distribution Network Planning and Expansion Framework.

By way of background to this submission, the CDC strongly supports the objectives of the National Strategy on Energy Efficiency. Furthermore, the CDC is conscious of the very important role that distribution network investment plays in improving the efficiency of electricity delivery and in assisting Australia to effectively meet its international obligations including its Kyoto commitments.

The economic value that should be ascribed to losses in the electricity supply system is a matter to which the CDC has given some attention in recent times. To this end, the CDC supported an independent review of the long-run cost of electrical losses within NSW distribution systems.

A paper describing the cost of losses methodology and outcomes accompanies this submission. For different load profiles, this methodology aggregates[1]:

- The long-run incremental cost of generation, based on AEMO's research;
- The long run marginal costs of expanding the upstream distribution and transmission networks to deliver energy to the point at which it is consumed, or lost; and
- The incremental upstream losses to deliver energy to the point in the network at which it is consumed, or lost.

This review has indicated that the long-run marginal cost of electrical losses, which is appropriately used in evaluating distribution investments, is much greater than the average market value of energy. Moreover, as there is now greater clarity concerning the implementation of carbon pricing in Australia, this also needs to be factored into the long-run cost of losses.

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1 Colebourn H, The cost of losses for future network investment in the new networks regime. Presented to the September 2010 conference of the Electric Energy Society of Australia conference in Sydney in September 2010.

The National Electricity Objective[2] will clearly be promoted if an appropriate value is ascribed to the long-run cost of electrical losses in DNSP investment decisions, wherever it is practicable to do so. This must lead to improved economic efficiency and a long term reduction in costs to consumers.

The CDC understands that a methodology for valuing losses such as that described above is not in common use by DNSPs. In addition, the current regulatory framework for DNSPs does not require them to consider the cost of electrical losses but instead applies strong incentives for DNSPs to minimise both capital and operating costs, which would encourage high-loss outcomes.

The CDC compliments the AEMC on ensuring that, in the revised distribution investment framework, DNSPs must give consideration to electricity network losses in their major investment decisions. Clause 5.6.5CA(c)(4)(vii) of the proposed Rule change requires this consideration.

In view of the broad range of values that could be ascribed to electrical losses by the DNSPs, the CDC considers that guidance should be provided to DNSPs on the way in which the economic value of losses in the network is to be determined. Accordingly, the CDC proposes the following additional sub-clause, for inclusion in the Application Guidelines for the new Regulatory Investment Test for Distribution (RIT-D):

> 5.6.5CA(h)(3A) an appropriate methodology for valuing the long-run costs of *electrical energy losses*;

The CDC considers that this additional guidance would lead to much less diversity in the DNSPs' analysis, more robust outcomes and improved overall economic efficiency. This is equivalent to the guidance provided in the Application Guidelines for TNSPs for the Regulatory Investment Test for Transmission (RIT-T).

Investment decisions are not confined to the major investments that are the subject of the currently proposed Rule change. There are many other decisions that should also be influenced, including:

- Smaller projects, below the $5 million threshold of the RIT-D;
- The specification of 'standard' conductor sizes;
- The design and location of substations;
- Transformer characteristics;
- Equipment utilisation levels; and
- Operating practices.

Whilst certainly a step in the right direction, the current Rule change proposal for the Distribution Network Planning and Expansion Framework does not capture these types of investment decisions. The CDC is therefore preparing a separate proposal for a Rule change, to address this issue. This proposal would also draw upon the AER guidance on the cost of losses proposed in this document. I will be in touch shortly with the details of this proposal.

In summary, the economic regulatory framework for network businesses needs to more closely align with energy efficiency policy frameworks. This is particularly important for critical investment decisions being taken today, concerning assets that will service the needs of future generations.

Please do not hesitate to contact me if further explanation of this submission would assist the Commission with its deliberations. Our experts will be made available to help clarify any issues this submission raises.

2 "... to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to ... price ...."

Yours sincerely,

**John J Fennell**
**Chief Executive Officer**
**Copper Development Centre • Australia Ltd**

Attachment - please refer to the attached document by Harry Colebourn "Cost of losses v02.pdf".

# The cost of losses for future network investment in the new networks regime

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## Introduction

The supply industry is at a turning point, where the forecast costs of energy generation are expected to increase markedly beyond "traditional" levels and current market prices. The reasons for this are three-fold:

- The prospect of climate change has influenced Government policies to encourage a move to renewable energy sources;
- There is the strong likelihood of some form of carbon price in the near future, which will also increase the costs of energy generation; and
- Networks have been the subject of recent regulatory determinations, that for most have dramatically increased their capital and operating expenditure allowances.

This paper sets out an approach to determining forward-looking long run costs for the three main supply chain components of the cost of losses:

- Energy generation;
- The provision of network capacity; and
- The provision of incremental upstream losses.

The analysis in this report has provided average loss costs by voltage level and is specific to the NSW region of the Australian National Energy Market (NEM). However, it provides a clearindication that a significant change in the cost of losses now needs to be factored into investment analysis across the NEM.

The cost of losses can be a significant input to the planning, design and operational activities of network businesses. Whilst the cost of losses will rarely provide the complete justification for an augmentation project, it can change the relative ranking of alternatives (particularly when comparing augmentation options with different voltages). The cost of losses can also influence the preferred timing of an augmentation project, where moderate load growth permits this.

The cost of losses thus has potentially significant implications for the following types of investment decisions, which are routinely made by transmission and distribution network businesses:

- The choice of economically efficient augmentation options, including the choice of supply voltage level; and
- Lifecycle costs used for equipment specifications, such as optimal underground cable and line conductor sizes and transformer designs, are critically dependent on this input.

Network businesses do not incur the direct cost of losses, which are settled between trading participants in the NEM. Nonetheless, there is a direct requirement for these businesses to factor loss costs into their investment analysis, to support the NEM objective "to promote efficient investment in, and use of, electricity services for the long term interests of consumers of electricity with respect to price …”.

The Ministerial Council on Energy (MCE) has directed a review of the National Electricity Rules (the Rules) and regulatory framework on distribution network planning and expansion, including the requirements for network investment. The treatment of loss costs in investment analysis is an important factor in those considerations.

The cost of losses is also a determining factor in establishing the Minimum Energy Performance Standards (MEPS), for appliances and equipment such as distribution transformers. The specification of revised Stage 2 distribution transformer MEPS is currently underway as part of the Australian Governments’ Equipment Energy Efficiency Program (E3). The consultation Regulatory Impact Statement (RIS) on revised distribution transformer MEPS is awaited at the time of writing.

# Contents

# 1. Foundations for the analysis of electrical loss costs

Investment in network infrastructure usually involves the installation of additional or replacement equipment having a life span of 30 years or more. It follows that the total ownership cost of the investment must be assessed from the associated capital and operational costs over a commensurate period.

The cost of electrical losses forms a component of virtually every network investment, although for some investments it is not a material component. In addition, some network investments are made to maintain prescriptive network security or reliability criteria. Nevertheless, the consideration of loss costs should accompany every network investment and their detailed assessment should be incorporated, where the loss costs are material.

***Long Run Marginal Costs***

In economic terms, the Long Run Marginal Cost (LRMC) over the period of investment analysis is the appropriate cost to be applied to losses. In this report, the major components of the cost of losses have been considered on this basis.

In relation to the costs of energy generation, estimates of future generation costs need to incorporate the influence of some externalities which are expected to have potentially significant effects, namely the Mandatory Renewable Energy Target (MRET) requirements and a carbon price, through a mechanism such as the Carbon Pollution Reduction Scheme (CPRS).

***Cost basis***

The convention used in this report is that all costs have been expressed in 2009-10 Australian dollars. Where source material from other years was used, the cumulative CPI index published by the Australian Bureau of Statistics (ABS) was used to adjust costs[1]. Estimated costs in other currencies were firstly converted to Australian dollars using the average conversion rate applicable to their year of estimation and then indexed to 2009-10[2].

***Regional basis***

For the purpose of this analysis, the NSW region of the National Energy Market (NEM) has been chosen and indicative loss costs for a metropolitan (EnergyAustralia) and a regional (Country Energy) distributor have been estimated. Despite this scope limitation, the results provide a clear indication of changed conditions that apply across the NEM, albeit with some regional and distributor specific variations.

***No-load loss and load loss***

The losses that are associated with the operation of electrical equipment need to be considered in two separate categories because of their differing impact on the power system, as follows:

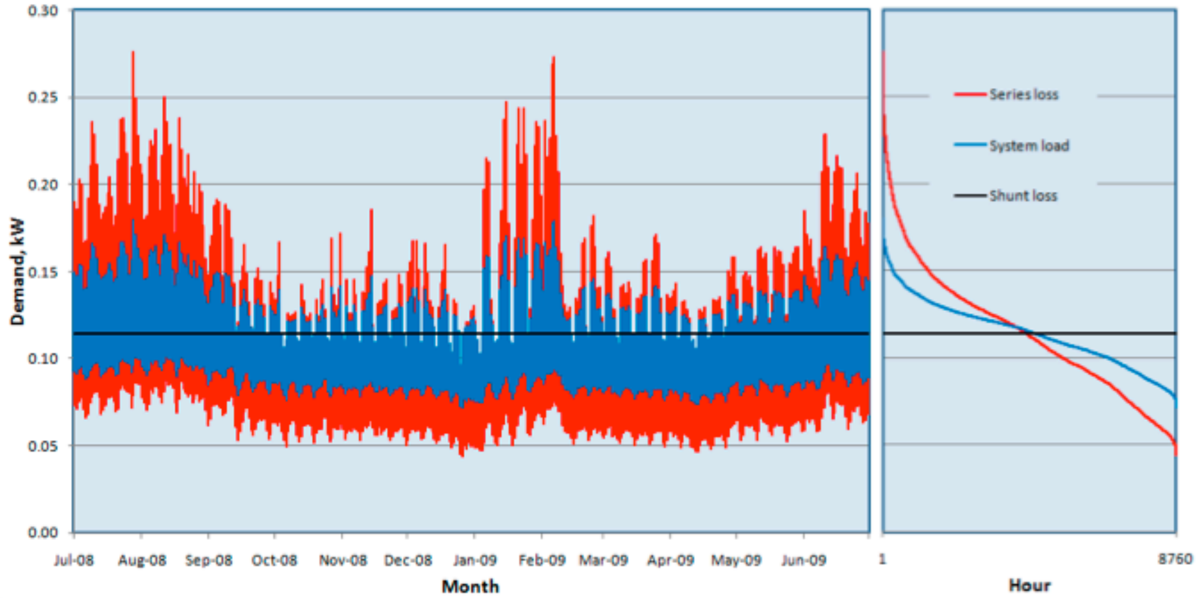
- No-load (or shunt) loss is a relatively constant leakage loss, which is independent of the equipment loading and takes place whenever the equipment is energised; and
- Load (or series) loss depends upon the electrical load supplied by the equipment. The load losses vary with the square of the load current imposed on the equipment.

1 Australian Bureau of Statistics, 6401.0 - Consumer Price Index, Australia- Weighted average of eight capital cities, 27 January 2010.

2 Reserve Bank of Australia, F11 Exchange rates, 9 December 2009.

Figure 1 illustrates the half-hourly demand associated with load and no-load losses, compared with the demand profile of the average system load in the NSW region of the NEM for the year 2008/09[3]. The three load and loss profiles are scaled for a normalised consumption of 1 MWh per annum. The blue trace represents the system load, the constant black trace the no-load loss profile and the red trace the load loss profile. This illustration serves to highlight how these very different load profiles affect the peak period demand, with a constant quantum of delivered energy. The annual load duration curves at right further highlight the comparison.

### Figure 1 – Profile of system demand and losses




In the chart at left, which shares the same y axis, the load profile displays the seasonal and weekly variation associated with electricity consumed. At right, the same hourly information is reordered to display the load duration curve associated with the different consumption profiles.

It follows that in evaluating the cost of losses for investment analysis, the consideration and separate costing of their two components, load and no-load losses, is necessary. Their very different consumption profiles and influence on peak demand affect the cost of both energy generation and of network delivery.

***Components of the cost of delivered energy***

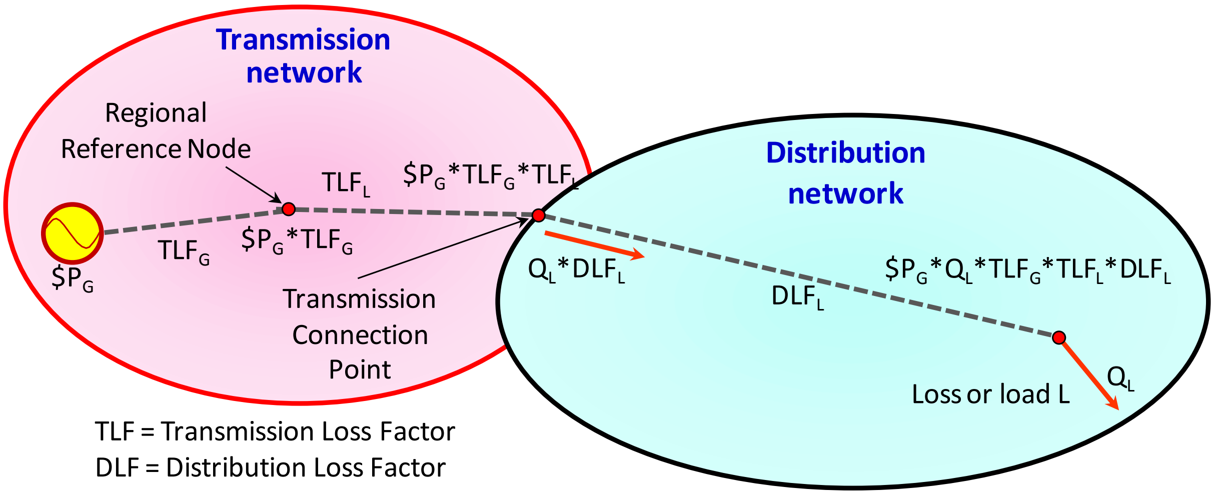
The structure of the Australian NEM and the disaggregated entities in the supply chain are illustrated in Figure 2. In this illustration, the market settlements arrangement for energy delivered to a point in the distribution network is shown.

Losses within the transmission network are accounted for with transmission loss factor adjustments, which apply to the prices at all connection points to the transmission network. These are marginal factors that adjust the regional reference price (RRP). In most, but not all, cases, the price paid to generators is less than the RRP and the price paid by retailers at load connection points is greater than the RRP.

[3] NEM consumption and price data is available from the AEMO web site at http://www.aemo.com.au/data/price_demand.html.

Distribution loss factors act as volume adjustments from the point in the network where load is connected to the relevant transmission connection point. Distribution loss factors are average quantities which increment the load by the losses within that network.

### Figure 2 - Market settlements in the NEM




Whilst transmission loss factors act as price multipliers and distribution loss factors act as volume multipliers in the market settlements, the cost outcome of settlements for load supplied to the distribution network is the multiple of all upstream loss factors, the generator price and the volume. Thus for a load $Q_L$ connected in the distribution system:

| | | |
|---|---|---|
| Generator bid price | $\$P_G$ | |
| Price of energy at market RRN | $P_{RRN}$ | $= \$P_G * TLF_G$ |
| Price of energy purchased from market at transmission connection point | $P_{TCP}$ | $= P_{RRN} * TLF_L$<br>$= \$P_G * TLF_G * TLF_L$ |
| Volume of energy purchased from market at transmission connection point | $Q_{TCP}$ | $= Q_L * DLF_L$ |
| Cost of energy delivered to distribution system | Cost | $= P_{TCP} * Q_{TCP}$<br>$= \$P_G * TLF_G * TLF_L * Q_L * DLF_L$ |

Transmission and distribution costs also need to be added to the cost of energy delivered within the distribution network. The Transmission and Distribution Use of System (TUoS and DUoS) costs are all ultimately recovered from customers.

These elements taken together make up the cost of delivered energy (or of lost energy) and are described in Figure 3.

### Figure 3 - Components of the cost of delivered energy

| | |
|---|---|
| **Generation** | Energy is delivered to the market from these locations. Generator bids need to cover the fixed and variable costs of energy production, plus transmission costs and transmission losses incurred in delivery to the market. |
| **Transmission network** | |
| Transmission loss | Transmission losses adjust the generator bid price. |
| Transmission cost (TUoS) | A minor component of transmission cost is levied on generators and recovered through their market bids. |
| **National Energy Market** (NEM) | Energy is settled on a half hourly basis in the market at the Regional Reference Node (RRN). |
| **Transmission network** | |
| Transmission loss | Transmission losses adjust the market purchase price at the transmission boundary. |
| Transmission cost (TUoS) | The major component of transmission cost adds to the cost of delivered energy. |
| **Transmission - Distribution boundary** | Wholesale energy is purchased from the market at this interface. |
| **Distribution network** | |
| Distribution loss | Distribution losses adjust the volume of energy that must be purchased from the market. |
| Distribution cost (DUoS) | Distribution costs add to the cost of delivered energy. |

Energy consumed at a point within a distribution network affects each element of the upstream energy supply chain, increasing both:

- The quantum of energy required; and
- The cost of energy delivered to that point.

Each of these component costs is now considered in turn.

## 2. Energy generation costs

For the purpose of comparison, two sources of generation cost have been considered:

- Wholesale energy market related costs, from 2008/09; and
- Forward looking generation costs, using the most recently available estimates of alternative generation technologies.

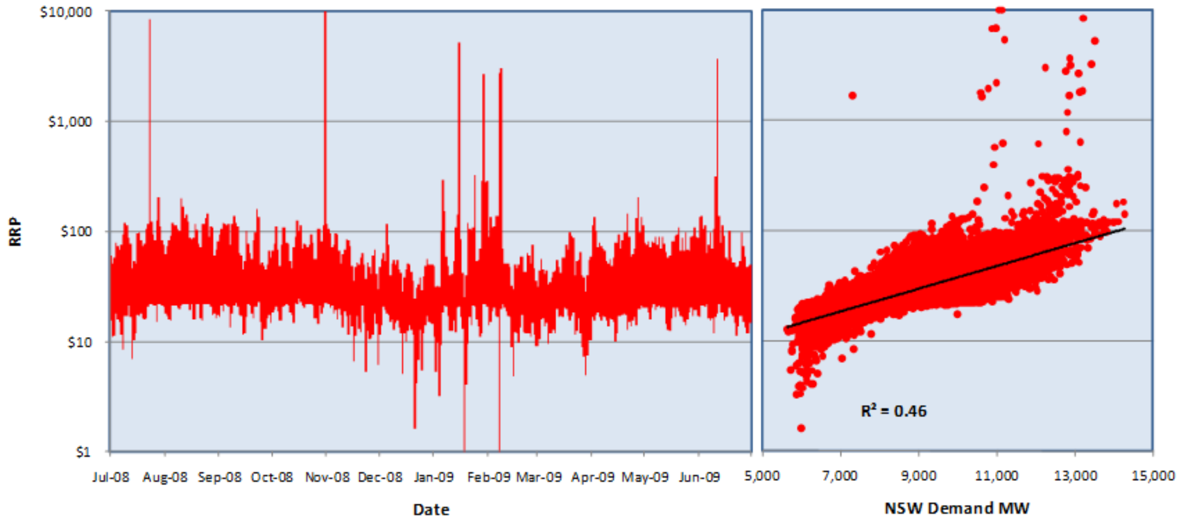
## 2.1 Wholesale energy market costs

The most recent full year of wholesale market data, for 2008/09, provides the actual cost of losses that would have been incurred in that year, at the level of the RRN. The half-hourly Regional Reference Price (RRP) or pool price varied throughout a great range during the year, from a maximum capped at $10,000, to a minimum of -$105.15.

In Figure 4, the maximum and minimum daily values of the RRP have been shown in the left hand bar chart. Negative prices were excluded to enable a logarithmic vertical scale, necessary to compress extreme pool price excursions.

There is a reasonable correlation between the RRP and the NSW region demand, as evidenced by the $R^2$ value of the scatter plot at right. Here, an exponential best-fit trajectory appears as a straight line with the logarithmic scale. The two charts have the same vertical scale.

**Figure 4 - Pool price and regional demand for NSW, 2008/09**




Analysis of the half hourly settlements data for the year to determine the cost of losses is carried out in three ways:

1. A simple average of the RRP. This would correspond with the average wholesale cost of energy supplied to a constant load (or no-load loss);

2. A load weighted average of the RRP, represented by the following formula:

$$P_1 = \frac{\sum_{n=1}^{17,520} RRP_n \bullet D_n}{\sum_{n=1}^{17,520} D_n}$$

   Where:

   $RRP_n$ is the RRP for half hour *n*; and

   $D_n$ is the Regional Demand supplied by the market in half hour *n*.

   The load weighted average price is the wholesale cost of supplying a load with the same profile as the system average; and

3. A load-squared average of the RRP, represented by the following formula:

$$P_2 = \frac{\sum_{n=1}^{17,520} RRP_n \bullet D_n^2}{\sum_{n=1}^{17,520} D_n^2}$$

The average price so calculated is the wholesale cost of supplying a load with the same profile as the load losses incurred in supplying a load with the system average profile (since the load loss is proportional to the square of the load).

These average wholesale costs, indexed to $2009/10, are set out in Table 1.

### Table 1 - Wholesale energy costs of supply, 2008/09

| Load profile | No-load loss | System load | Load loss |
|---|---|---|---|
| Wholesale cost of supply | $39.80 | $43.80 | $48.40 |

The correlation between the RRP and the regional demand may be seen as an increased cost associated with the supply of energy to a more 'peaky' load profile.

## 2.2 Forecast energy market costs

The wholesale prices of section 2.1 are the outcome of market settlements, in which the generator bids and associated contracts with retailers recover their costs. The cost of energy delivered to the market includes the following components:

- Energy production;
- Transmission network losses; and
- Transmission network charges.

Each of these components is considered in turn, to develop a forecast of future energy costs.

***Generation costs***

The most recently available forward-looking generation cost information is contained in the Australian Energy Market Operator's (AEMO) 2009 generation cost review[4]. ACIL Tasman was engaged to develop this data for the primary purpose of conducting market simulation studies. These studies were undertaken to identify the requirement for additional transmission infrastructure in the NEM, given projected generation expansion scenarios.

ACIL Tasman developed Short and Long Run generation cost forecasts for a range of future generating technologies, with locational variations for 16 regional zones across the NEM. The costs were estimated over a period extending to 2028-29. In this report, these costs have been summarised as averages over the four zones covering NSW and the ACT. Although there is not a great deal of cost variation after the introduction of the CPRS, a mid-range date of 2019-20 for new generation was chosen for this comparison.

The information in the ACIL Tasman report pertains to those generation technologies that can be dispatched in the market. It thus does not include some forms of renewable generation, notably wind and solar. An alternative recent Australian source of information on those costs is McLennan

4 ACIL Tasman, Final Report Fuel resource, new entry and generation costs in the NEM Prepared for the Inter-Regional Planning Committee, April 2009.

Magasanik and Associates' (MMA) report prepared for the Australian Geothermal Energy Association[5].

The costs of new technology generation are summarised in Table 2.

### Table 2 - LRMC of new generation technologies introduced in 2020

| Technology | Capacity factor | LRMC excluding CPRS $/MWh generated | LRMC including CPRS[6] $/MWh generated |
|---|---|---|---|
| CCGT | 85% | $57 | $74[7] |
| OCGT | 15%[8] | $156 | $183[7] |
| Coal | 85% | $48 | $77[7] |
| Geothermal | 85% | $78 | $78[7] |
| Advanced coal | 85% | $67 | $79[7] |
| Nuclear | 85% | $98 | $98[7] |
| Wind | 30%[9] | $105 | $105[10] |
| Biomass | 85%[11] | $113 | $113[10] |
| Large solar | 30%[11] | $268 | $268[10] |
| Small solar photovoltaic | 20%[11] | $522 | $522[10] |
| Key: CCGT = Combined cycle gas turbine; OCGT = Open cycle gas turbine; Advanced coal = Ultra-supercritical coal and Integrated gasification combined cycle; Large solar = solar collector or solar thermal; Small solar = rooftop solar photovoltaic. | | | |

It is feasible to simplify this range of future new generating technologies somewhat, for the purposes of the analysis in this report. The existing, committed and proposed generation capacity forecast in the AEMO statement of Opportunities, which covers the period to 2019, was used[12]. The following simplifications have been made:

- AEMO does not anticipate any nuclear or geothermal contribution in NSW by 2019 and these technologies have therefore been excluded;

5 McLennan Magasanik and Associates. Report to AGEA (Australian Geothermal Energy Association) - Comparative Costs of Electricity Generation Technologies, February 2009.

6 Assumes carbon prices as per Treasury's CPRS -5 scenario.

7 ACIL Tasman, April 2009, Table 52 and Table 53.

8 The ACIL Tasman cost estimates have been prepared with a uniform 85% capacity factor. This is not a realistic assumption for the operating regime of this form of generation, which has a relatively high fuel cost. An adjustment has been made to the LRMC to recover the capital component over a more typical capacity factor. Whilst OCGT facilities are often designed for capacity factors of 30%, their utilisation in NSW is more likely to fall in the range of 10 to 15% to meet the NSW requirement for peaking generation, highlighted by the load duration in Figure 5.

9 MMA, February 2009, p.2 (assumed to lie at the lower end of the range of 28% to 43%).

10 MMA, February 2009, Table 3-1.

11 Energy Information Administration - Report #:DOE/EIA-0554(2009) - Assumptions to the Annual Energy Outlook 2009, March 2009, Table 13.2.

12 Australian Energy Market Operator, 2009, Electricity Statement of Opportunities, Chapter 4.

- The cost of energy generated from coal and advanced coal is very similar. The cost of coal has been used;
- Wind, biomass, geothermal and large solar generation sources are unscheduled. Moreover, the anticipated contribution of both biomass and solar is relatively small. They have been therefore been grouped together and their weighted average cost used; and
- Small-scale rooftop solar photovoltaic is the most expensive of the energy generation options and its recently increased penetration has been as a result of subsidies for the installation of units of 1.5 kW or less, Renewable Energy Certificate (REC) entitlements and jurisdictional solar feed-in tariffs[13,14]. This form of energy generation is not settled in the market and has been excluded on the basis that it would be incorporated into AEMO's energy and demand projections by being netted off customer demand and energy.

***Transmission network losses for generators***

The capacity-based average of AEMO's 2009/10 marginal loss factors for major NSW generators is 0.9659[15]. That is, on average these generators lose approximately 3.5% of revenue derived through market settlements, due to the application of marginal transmission loss factors.

It has been assumed that the majority of new generation technologies are likely to be located at existing generation sites or similarly located sites. The delivered cost of energy to the market would therefore carry this 3.5% mark-up.

Wind generation is most likely to be located in remote locations, with either transmission or high capacity distribution connections to the interconnected network and load centres. For this reason, an additional loss of 5% has been assumed for this form of generation.

***Transmission network costs for generators***

The existing major generators in NSW pay a small component of Transmission Use of System (TUoS) to TransGrid for their dedicated connection assets[16]. This cost has been averaged over the energy delivered to the grid by power stations, to obtain a $/MWh connection cost[17].

This transmission cost has been assumed to apply to similarly located new generators, again with the exception of wind. In the case of wind generators an additional transmission charge, equivalent to an investment of $20 million in a dedicated transmission connection for each 100 MW of generation was added.

***Summary of the forecast cost of energy generation***

A summary of the cost of energy delivered to the market RRN for the alternative generation technologies is set out in Table 3.

[13] McLennan Magasanik and Associates. Report to Department of Climate Change - Benefits and Costs of the Expanded Renewable Energy Target, January 2009, p.30.

[14] KPMG, NEMMCO Ltd - Stage three - Semi-scheduled, Non-scheduled and Exempted Generation, by fuel source in NEM regions 2008-9 to 2028-29 - Final Report, March 2009.

[15] NEMMCO (now AEMO), List of Regional Boundaries and Marginal Loss Factors for the 2009/10 Financial Year - Version No. 2.0 - Final, 30 April 2009.

[16] TransGrid, TransGrid's Transmission Prices - 1 July 2009 to 30 June 2010, 14 May 2009.

[17] TransGrid, New South Wales Annual Planning Report, 30 June 2009, Table A3.1, p.78.

### Table 3 - Forecast cost of generation delivered to the Regional Reference Node

| Technology | Capacity factor | LRMC incl. CPRS $/MWh generated | Loss Cost $/MWh | TUoS $/MWh | Total $/MWh delivered |
|---|---|---|---|---|---|
| CCGT | 85% | $74 | $2.60 | $0.30 | $77 |
| OCGT | 15% | $183 | $6.50 | $0.30 | $190 |
| Coal | 85% | $78 | $2.70 | $0.30 | $81 |
| Wind & unscheduled | 30% | $105 | -[18] | $9.20 | $114 |

***The forecast mix of existing and new generation types***

In order to forecast the cost of energy supply to loads of different profile, it is necessary to consider the way in which the different energy sources with different costs and capacity factors are likely to be despatched for operation in the NEM. The NSW profile for 2009/09 was used to develop the generator mix. This profile had a maximum half-hourly demand of 14,152 MW. The profile was scaled to 16,850 MW in 2019-20, to match the forecast summer demand growth of 2.1% over the period[19].

The capacity of existing, committed and proposed generation in NSW was taken from AEMO's Statement of Opportunities. This is summarised by generator type, in Table 4[20].

### Table 4 - Existing, committed and proposed generation in NSW

| Technology | MW, Summer | |
|---|---|---|
| | Scheduled and semi-scheduled | Unscheduled |
| CCGT | 1,452 | 0 |
| Coal | 14,865 | 0 |
| OCGT | 3,930 | 263 |
| Biomass | 0 | 214 |
| Hydro | 2,436 | 190 |
| Wind | 2,250 | 214 |
| Total | 24,933 | 881 |

Based on the above assumptions, Figure 5 illustrates the likely mix of the types of generation described in section 0, with the addition of the existing hydro stations (principally Snowy). Snowy Hydro has installed capacity of 3,746 MW and annual average generation of 4,500 GWh, which equates to an annual capacity factor of around 14%[21]. Its price was set equal to OCGT as it provides similar economic value to the market.

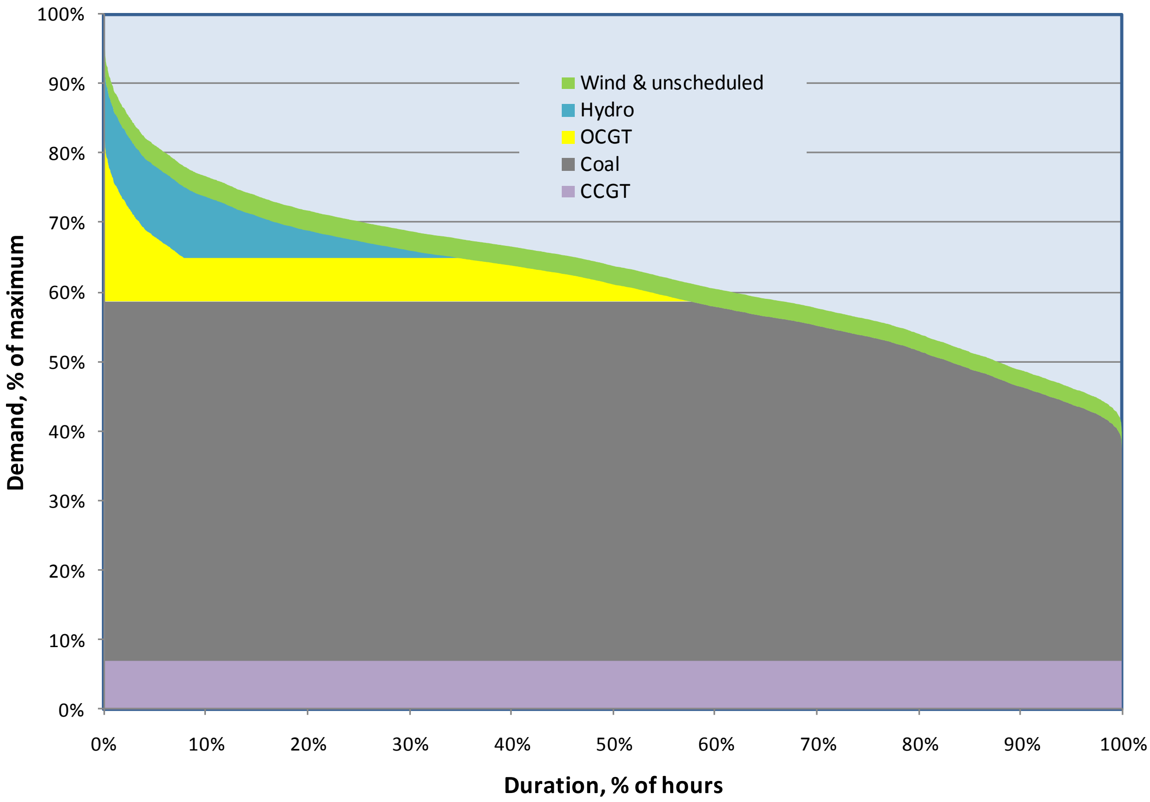
18 The cost of transmission losses is included in the LRMC estimate by MMA.

19 TransGrid, New South Wales Annual Planning Report 2009, Table 3.2, p.79.

20 AEMO 2009 ESoO, Chapter 4, Tables 4.5, 4.6, 4.17 - 4.20, pp.4-10 to 4-38.

21 Intelligent Energy Systems, Insider, 31 March 2006, p.2.

**Figure 5 - Forecast mix of existing and new generation by 2020**




Wind and unscheduled generation was assumed operate with the peak demand and capacity factor assumed in AEMO's 2009 Statement of Opportunities. The coincident reduction in peak demand is 540 MW, and the reduction in energy 1500 GWh, which equates to an annual capacity factor of 31.7%[22].

## 2.3 Summary of forecast energy market costs

The incidence of costs arising from the assumed generation mix in section 0, for loads of different profile, is set out in Table 5.

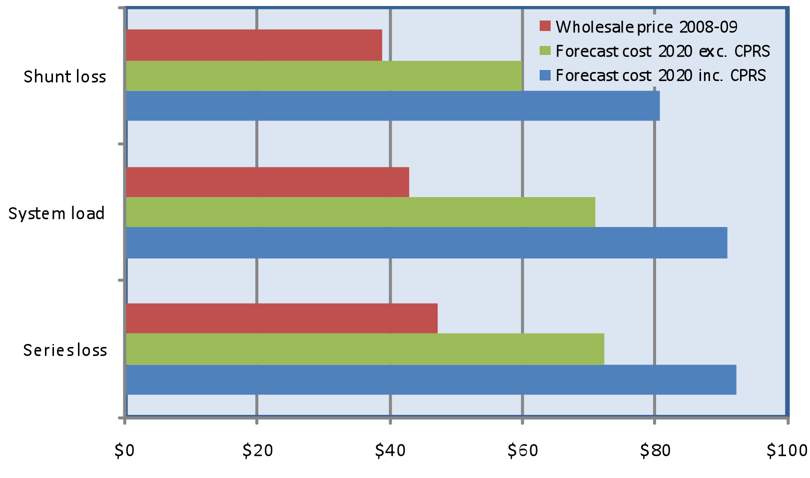
**Table 5 - Long Run costs of energy supply, 2020**

| Load profile | No-load loss | System load | Load loss |
|---|---|---|---|
| Forecast cost of supply | $80.80 | $90.90 | $92.40 |

These forecast costs are compared with the 2008/09 wholesale energy costs in Figure 6.

22 AEMO 2009 ESoO, Chapter 3, pp.3-24, 3-28.

**Figure 6 - Comparison of 2008/09 wholesale energy market costs with forecast costs**




The forecast costs of energy supply are significantly greater than 2008/09 wholesale supply costs set out in section 2.1. Effectively, the market is currently clearing at a price that is closer to the forecast 2020 Short Run Marginal Cost (SRMC) of energy supply without CPRS, of approximately $25/MWh for the equivalent generation mix.

The influence of the load profile on generation costs remains apparent.

# 3. Energy delivery via the transmission and distribution networks

The incremental capacity costs and upstream energy losses associated with losses incurred within different levels of the network are described in this section.

## 3.1 Incremental network capacity costs

Network businesses are highly asset intensive and the associated asset related costs constitute the majority of their revenue requirement. It follows that the main determinant of network cost is the provision of capacity in the network, requiring its augmentation. Losses incurred in the network add marginally to the capacity required to supply load and need to be costed on an equivalent basis to load requirements.

Network assets have very long lives, generally in excess of 30 years, and often, lengthy construction times. Network augmentation is thus extremely 'lumpy' as there are large, high cost investments at irregular intervals. The costing of network services using a LRMC approach is appropriate to this situation. Asset costs are recovered through the return on and return of capital over the life of the asset and the cost of future development of network infrastructure can be reflected both in prices for the use of the network and in the valuing the cost of losses.

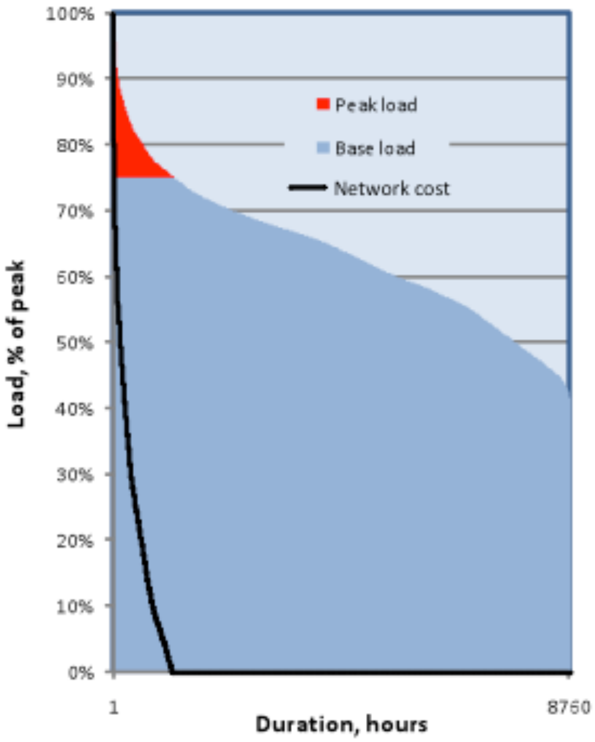
The first step in this process is to evaluate the LRMC of the network. The Net Present Value (NPV) of the future capacity augmentation investments and associated operating cost are spread over the associated increment in either demand or energy. Over a period of several years, for EnergyAustralia this calculation has resulted in an LRMC of approximately 80% of the average network revenue. In its most Pricing Proposal, EnergyAustralia revised its approach and estimated marginal costs, based on kVA, of between 51% and 142% for the major tariff classes[23]. The weighted average of almost 120% represents an increase on earlier years, caused by higher levels of capital spending in the 2009-14 regulatory control period. Equivalent information was not disclosed in Country Energy's 2009-10 Annual Network Pricing Report.

[23] EnergyAustralia, Network Pricing Proposal (Revised), May 2009, Table 5, p.47.

A cost allocation aligned with the requirement to invest in the network will provide an appropriate signal of the cost of providing capacity to meet peak period demand. The approach described in this paper is a modification of a cost allocation process termed the Method of Intercepts[24,25].

In this infrastructure based cost allocation, the network LRMC has been conservatively assumed to remain at 80% of the average network price. This cost was allocated to the upper 75% of system loading, since the network is generally augmented to provide capacity for loads above this level. The LRMC component of network cost is thereby allocated to the peak period loads. This concept is illustrated in Figure 7.

### Figure 7 - Network marginal cost allocation




In Figure 7, the allocated network cost may be seen to escalate rapidly to its peak value, as loads exceed the 75% threshold.

This network cost profile was applied to different loading profiles, to yield the network marginal cost allocation factors shown in Table 6.

### Table 6 - Network marginal cost allocation factors

| No-load loss | System load | Load Loss |
|---|---|---|
| 75% | 80% | 131% |

The network marginal cost allocation factors of Table 6 were applied to 2009-10 transmission and distribution prices, to determine the cost applicable to losses.

24 Armstead, C H Allocating Fixed Costs, Energy International, December 1969.

25 Colebourn H and Amos C, Pricing Signals for a Network Business, 8th Institution of Engineering and Technology conference on Advances in Power System Control, Operation and Maintenance, Hong Kong, November 2009.

### *Incremental network loss allocation*

The chart at right in Figure 1 illustrates very different profiles associated with no-load (shunt) losses, the system load and load (series) losses. Loss factors at both transmission and distribution are normally determined for the system load profile. These factors need to be adjusted in order to validly apply to loads with a different profile.

Table 7 sets out the adjustment factors applied to loss factors to accommodate loads of different profile.

**Table 7 - Network loss allocation factors**

| No-load loss | System load | Load Loss |
|---|---|---|
| 63% | 100% | 153% |

## 3.2 Transmission network costs

Transmission Network Service Providers (TNSPs) recover their revenue via Transmission Use of System (TUoS) charges to DNSPs. These costs apportioned to two NSW distributors are shown in Table 8[26]. The allocated revenue for the distributors was converted into an average price using the energy forecast contained in the AER's determination[27].

**Table 8 - Transmission network costs, $/MWh**

| Distributor | No-load loss | System load | Load Loss |
|---|---|---|---|
| Metropolitan | $6.60 | $7.10 | $11.60 |
| Regional | $12.30 | $13.20 | $21.60 |

The cost allocation factors of Table 6 were used to formulate Table 8.

### *Transmission network losses*

Transmission network losses are accommodated in the market by marginal loss factors used to adjust the price at the RRN to the point of connection to the transmission network. The marginal loss factors differ for each transmission connection point. Weighted averages of the transmission loss factors of two NSW distributors (EnergyAustralia and Country Energy) are shown in Table 9.

**Table 9 - Transmission network losses**

| Distributor | No-load loss | System load | Load Loss |
|---|---|---|---|
| Metropolitan | 0.8% | 1.3% | 2.0% |
| Regional | 1.4% | 2.2% | 3.3% |

The loss allocation factors of Table 7 were used to determine the percentages in Table 9.

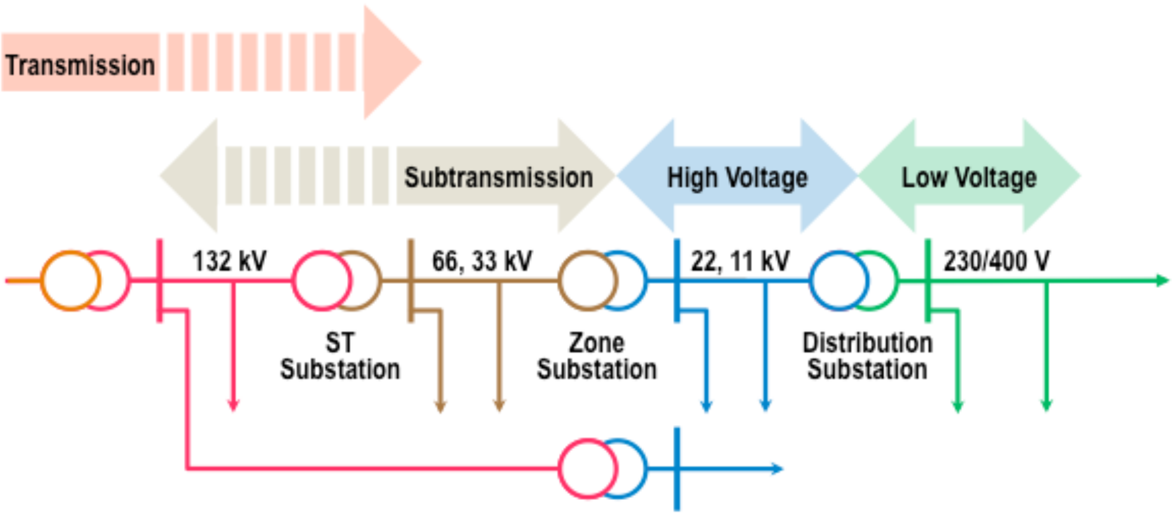
26 AER, Final decision TransGrid transmission determination 2009–10 to 2013–14, 28 April 2009, Table 9.5, p.122.

27 AER, Final decision New South Wales distribution determination 2009–10 to 2013–14, 28 April 2009, Table 16.24, p.321, Table 6.5, p.87, Table 6.3, p.85.

## 3.3 Distribution network costs

The typical structure of a distribution network and the levels of supply are shown in Figure 8. There can be overlap between assets of 66 kV or higher voltage, which are defined in the Rules as transmission if their function includes the support of the higher voltage transmission network.

**Figure 8 - Structure of the distribution network**




Customers are connected at all levels of the network, with larger customers at higher voltage levels and the great majority of small customers receiving supply at low voltage. The costs associated with the distribution network are assigned to cost pools for the classes of assets involved and allocated to downstream customers, generally in accordance with their utilisation of the asset cost pool.

The generic structure of Figure 8 does not highlight very significant differences between the structure of distribution networks that serve metropolitan and regional areas:

- Metropolitan networks have much greater load densities, shorter route lengths, a significant proportion of larger customers at higher voltage levels and often a greater proportion of underground construction; whereas
- Regional networks are characterised by low load densities, long overhead route lengths and outside regional centres, predominantly high voltage reticulation.

Distribution network pricing has become subject to a National compliance regime under the Rules, requiring the disclosure of information concerning matters such as the pricing allocation process, price levels and changes. The NSW pricing proposals were the first to be subjected to this regime, in 2009. The published information in the EnergyAustralia and Country Energy pricing proposals[28,29] was supplemented with other published information to derive the distribution network costs at different levels of the network[30,31].

28 EnergyAustralia, Network Pricing Proposal (Revised), May 2009, Table 12, p.59.

29 Country Energy, Annual network prices report 1 July 2009 – 30 June 2010, Figure 6, p.10.

30 AER, Final decision New South Wales distribution determination 2009–10 to 2013–14, 28 April 2009, Table 6.5, p.87.

31 EnergyAustralia, Distribution Loss Factor Calculation Methodology Paper, March 2009, Table 4, p.12.

The associated distribution network LRMC values are set out in Table 10 for each level of the network. These are cumulative - supply to a low voltage load would incur each upstream cost component.

**Table 10 - Distribution network costs, $/MWh**

| Distributor | No-load loss | System load | Load Loss |
|---|---|---|---|
| **Metropolitan** | | | |
| Subtransmission | $14.30 | $15.30 | $25.00 |
| High Voltage | $2.30 | $2.50 | $4.00 |
| Low Voltage | $30.00 | $32.20 | $52.70 |
| Total | $46.60 | $50.00 | $81.80 |
| **Regional** | | | |
| Subtransmission | $6.00 | $6.40 | $10.50 |
| High Voltage | $32.60 | $35.00 | $57.20 |
| Low Voltage | $34.30 | $36.70 | $60.10 |
| Total | $72.80 | $78.10 | $128.00 |

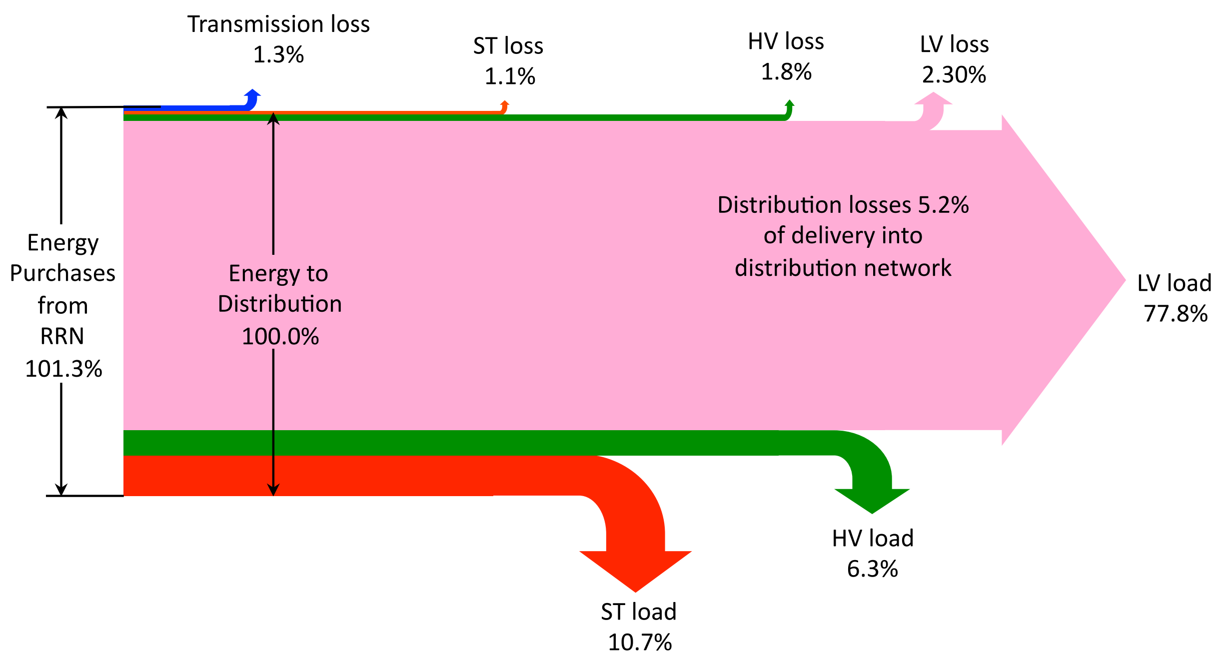
The cost allocation factors of Table 6 were also used in formulating Table 10.

## 4. Distribution network losses

Distribution losses take place at each of the levels of the network indicated in Figure 8. Those losses include the no-load and load losses in network elements and a small proportion of 'non-technical losses' to account for metering discrepancies and theft.

Distribution losses are also subject to a regulatory regime involving disclosure of the processes employed and approval of the resultant loss factors used for market settlements. Only one of these disclosure documents, EnergyAustralia's[31], provides a loss balance table, which has been used to develop the 'leaky pipe' diagram in Figure 9.

**Figure 9 - Distribution losses 'leaky pipe' diagram for metropolitan distributor**



In Figure 9, the relative proportions of both losses and load supplied at different levels of the network can be seen. A similar diagram for a regional distributor may be expected to reveal higher overall losses at transmission, subtransmission and high voltage distribution levels (totalling 10% or more). In addition, the lower energy density normally implies a smaller proportion of energy consumed at higher voltage levels, by larger customers.

The approved 2009-10 distribution loss factors used in market settlements by NEMMCO[32] were used to construct the table of loss factors in Table 11 for EnergyAustralia and Country Energy.

The percentages apply as a volume adjustment to the quantities settled at the market RRN.

### Table 11 - Distribution losses

| Distributor | No-load loss | System load | Load Loss |
|---|---|---|---|
| **Metropolitan** | | | |
| Subtransmission | 1.1% | 1.7% | 2.5% |
| High Voltage | 0.9% | 1.5% | 2.3% |
| Low Voltage | 2.3% | 3.5% | 5.4% |
| Total | | 6.7% | |
| **Regional** | | | |
| Subtransmission | 1.8% | 2.8% | 4.3% |
| High Voltage | 0.7% | 1.1% | 1.6% |
| Low Voltage | 4.0% | 6.4% | 9.8% |
| Total | | 10.25% | |

The loss allocation factors of Table 7 were used to determine the percentages in Table 11.

[32] AEMO, Distribution Loss Factors for the 2009/10 Financial Year - Version No: 4, effective August 2009, Table C5, p.14, Table C6, p.15.

## 5. Cost of losses within networks

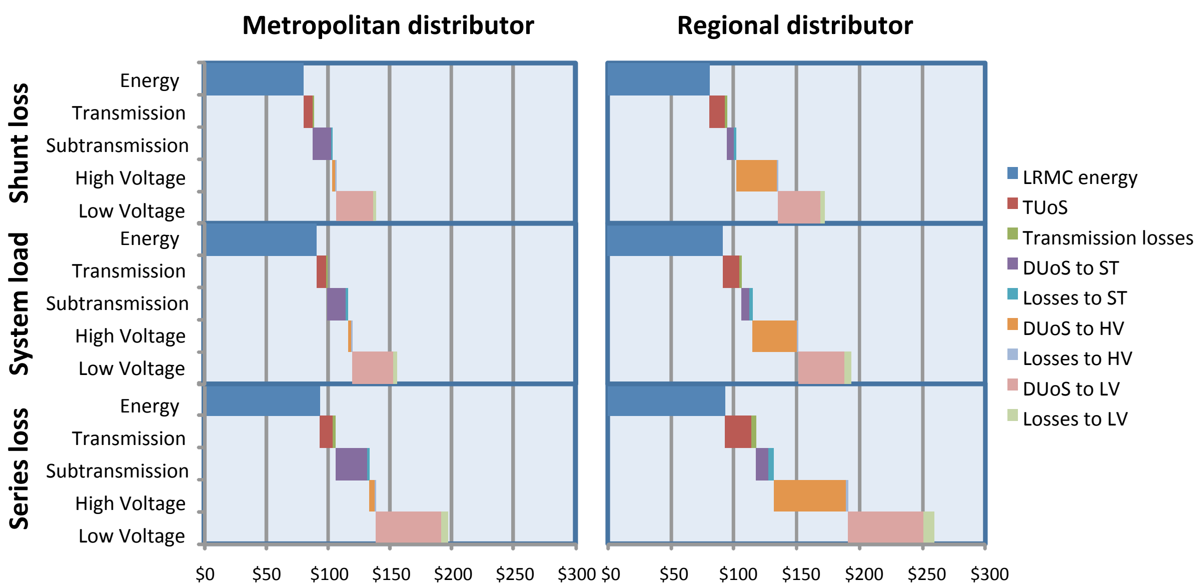
The elements described in sections 2 and 3 have been combined to yield the LRMC of supplying loads of different profile at different levels within the network. The outcome is shown in Table 12.

### Table 12 - Cost of losses within networks

| Distributor | No-load loss | System load | Load Loss |
|---|---|---|---|
| Market price | $38.90 | $42.80 | $47.30 |
| **Generation LRMC** | $80.80 | $90.90 | $92.40 |
| **Metropolitan LRMC** | | | |
| Transmission connection point | $88.10 | $99.10 | $106.00 |
| Subtransmission | $103.00 | $116.00 | $133.00 |
| High Voltage | $107.00 | $120.00 | $138.00 |
| Low Voltage | $139.00 | $155.00 | $196.00 |
| **Regional LRMC** | | | |
| Transmission connection point | $94.40 | $106.00 | $117.00 |
| Subtransmission | $102.00 | $115.00 | $131.00 |
| High Voltage | $135.00 | $151.00 | $190.00 |
| Low Voltage | $172.00 | $193.00 | $259.00 |

The cost of losses components at different levels in the network are also illustrated in Figure 10.

### Figure 10 - Cost of losses within networks



# 6. Concluding remarks

The foregoing analysis of the cost of losses follows very significant recent increases in the cost of two of their major components. The cost estimates include the necessary distinction between no-load and load losses.

## 6.1 Movement in the cost of losses

A similarly structured estimate of the long run cost of losses in 2005 yielded the costs set out in Table 13, for the low voltage level of EnergyAustralia's network.[33]

**Table 13 - Movement in the cost of losses**

| Review | Date | No-load loss | System load | Load Loss |
|---|---|---|---|---|
| 2005 analysis | July 2005 | $82 | $90 | $127 |
| … CPI adjustment | December 2009 | $94 | $103 | $145 |
| 2010 analysis | December 2009 | $139 | $155 | $196 |
| Increase | | 48% | 51% | 35% |

The analysis described in this report confirms that there has been a very significant increase in the value that should be attributed to losses in network investment analysis. This difference can be attributed to two influences:

- An increase in the cost of energy generated by new technologies, in which previously uneconomic forms of generation have become competitive due to the presence of the CPRS and RET; and
- Significant increases in network costs, arising principally from increased levels of capital expenditure to augment network capacity levels to match increased demand growth.

## 6.2 Distribution transformer MEPS

The cost of losses is the determining factor in establishing the MEPS for distribution transformers. The specification of distribution transformer energy performance requirements is currently underway as part of the Australian Governments' Equipment Energy Efficiency Program (E3). The consultation RIS is currently awaited.

It is recommended that in establishing the Stage 2 MEPS for distribution transformers, consideration needs to be given to:

- The significant increase in the cost of losses in establishing the efficiency levels; and
- A revised testing approach, which places greater weighting on the higher cost of load losses, in recognition of the greater cost of their provision.

## 6.3 Regulatory arrangements for network businesses

Network businesses do not purchase energy to make up losses from the market and there is currently no direct regulatory incentive scheme for distribution businesses to minimise their system losses.

It is apparent from the various examples appended to this report that there is a need for distribution businesses in particular to factor the cost of losses into their investment decision-making in a number

[33] Colebourn H, Cost of losses for network investment appraisal, Electric Energy Society of Australia Conference, 18 November 2005.

of different ways. Whilst no sub-optimal investment decisions were identified, the cost of losses was material in relation to a number of those decisions and if ignored could potentially lead to uneconomic development.

One solution that has been proposed to provide network businesses with an incentive to minimise network losses is to make them responsible for purchasing the energy losses in their networks from the market. This, however, has a number of significant drawbacks:

- As the analysis in this report has demonstrated, the cost of losses purchased from the market is substantially less than the long run cost that needs to be factored into the economic analysis of investment in assets with a service life of 30 years or more;
- For distribution businesses, the magnitude of system losses is significant, quite often larger than the energy consumption of their largest customer; and
- The purchase of lost energy would involve network businesses in market trading arrangements, which is at odds with the current intentional separation of their activities from trading; and
- That involvement in energy trading would introduce a significant level of risk exposure for which network businesses have not been structured or are currently financed.

The existing market arrangements for both transmission and distribution businesses do not provide them with a financial incentive to optimise the cost of lost energy. Rather, the market objective is promulgated through the Regulatory Investment Test.

The Regulatory Investment Test for Transmission (RIT-T) requires transmission businesses to analyse the market benefits associated with investments. To the extent that the market simulation used by TNSPs factors in the future cost of generation, as AEMO's does, an appropriate value would be placed on the cost of losses.

The Rules concerning distribution network planning and expansion are the subject of current review by the AEMC, at the direction of the MCE. A significant aspect of the new arrangements will be the review of the equivalent Regulatory Investment Test for Distribution (RIT-D). The policy intent has been established the AEMC and the associated RIT-D and Application Guidelines will be finalised by mid 2010.

Because of the relative significance of distribution losses and the attendant costs, it is apparent that the following elements need to be factored into the regulatory arrangements for distributors, to avoid a continuation of sub-optimal investment incentives:

- The long run cost of losses in distribution networks needs to be established on a uniform basis across the NEM, allowing for regional variation;
- AEMO is clearly the organisation best equipped to determine the cost of losses at the transmission connection level, using the same future generation costs as this report;
- Each distributor should be required to estimate the average cost of losses at applicable levels within its network, for use in investment analysis;
- Each distributor should be required to demonstrate that an appropriate value has been ascribed to the cost of losses in its equipment specification and purchasing decisions;
- The RIT-D should require DNSPs to carry out a simplified screening test for each network investment, to determine whether the cost of losses would have a material impact on the outcome;
- The investment appraisal for large augmentations should use individually calculated, rather than averaged loss costs;

- There is a need for a general regulatory incentive (equivalent to the STPIS) to provide appropriate funding levels for relatively small investments such as power factor correction and loss reduction in rural areas.

## 7. Acknowledgement

The author gratefully acknowledges the financial support of the Copper Development Association in carrying out the analysis described in this document.