COPPER

Copper Development Centre. Australia Limited

Copper Development Centre. Australia Limited
ABN 40 067 486 300
Suite 1, Level 7, Westfield Towers
100 William Street, Sydney NSW 2011
Ph: (+612) 9380 2000 Fax: (+612) 9380 2666

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5 April 2011

Submission to AEMC Strategic priorities for energy market development

Mr J Pierce
Commission Chairman
Australian Energy Market Commission (AEMC)
PO Box A2449
Sydney South NSW 1235
Australia

Dear Sir,
A discussion paper on the above topic was issued by the Australian Energy Market Commission (AEMC) requesting comment to be forwarded by 13 May 2011. It is noted that the primary objective is "promoting the economic efficiency of energy markets over the long term". It is also noted that this is divided into allocative, productive and dynamic components.

This submission seeks to address the productive component in identifying the changes in power generation and delivery to the consumer over the long term towards 2050. Australia has more than 10,000 MW of wind generation proposed, mostly in remote areas, requiring connection to the power system for delivery to the customer, incurring increased losses and corresponding reduction in efficiency of supply. It means that a significant proportion of new generation will be at low voltage ~600 V compared with the previous high voltage ~25kV and the consequences of this will require an "assembly" network which will bring many small generators together for transmission.

It also identifies the change from a "distribution" network to an "exchange" network requiring considerably heavier cables to enable two way flow of power with local generation. This network is fundamentally different in nature in operation, maintenance and safety.

These new arrangements will increase losses associated with every network and thus reduce the efficiency of operation. Suggestions are made to minimize these losses over the longer term, and a number of contributions from Australian sources have been attached to this letter.

These papers provide specific information on the consequences of the addition of this proportion of renewable generation and methods of keeping the overall efficiency of generation and delivery to the customer at as high a level as possible.

The Copper Development Centre. Australia has prepared these documents as part of its support for orderly and efficient development of the power industry for which it is a significant provider of basic material.

Yours Sincerely

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

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

Harry Colebourn, C Eng, MIET
BSc, BE (Hons), MEngSc, MBA
Energeia Pty Ltd
Phone: 61 2 9428 2668
Mobile: 61 412 328 549
Email: hcolebourn@bigpond.com

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:

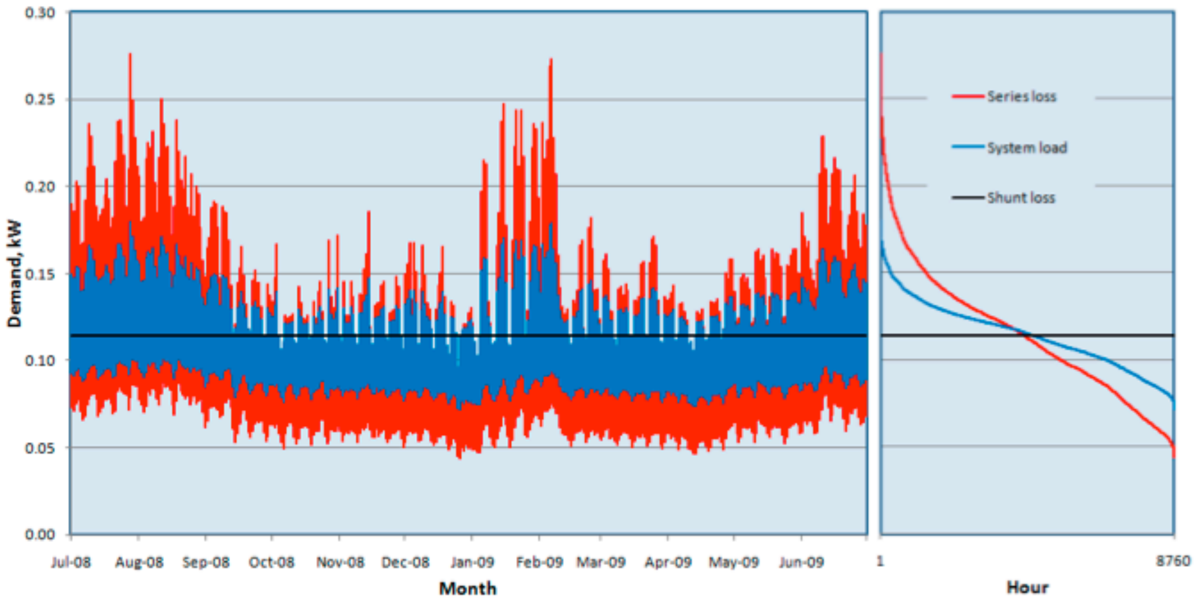
- No-load (or shunt) loss is a relatively constant leakage loss, which is independent of the equipment loading and takes place whenever the equipment is energised; and
- Load (or series) loss depends upon the electrical load supplied by the equipment. The load losses vary with the square of the load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

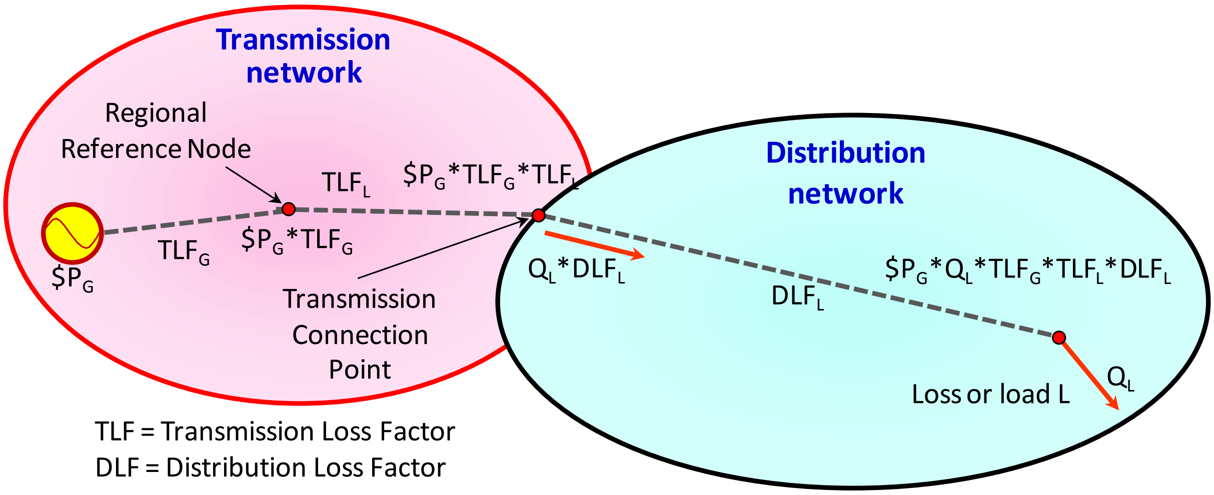
The structure of the Australian NEM and the disaggregated entities in the supply chain are illustrated in Figure 2. In this illustration, the market settlements arrangement for energy delivered to a point in the distribution network is shown.

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}	$= P_{RRN}*TLF_L$ $= \$P_G*TLF_G*TLF_L$
Volume of energy purchased from market at transmission connection point	Q_{TCP}	$= Q_L*DLF_L$
Cost of energy delivered to distribution system	Cost	$= P_{TCP}*Q_{TCP}$ $= \$P_G* TLF_G*TLF_L* Q_L*DLF_L$

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.

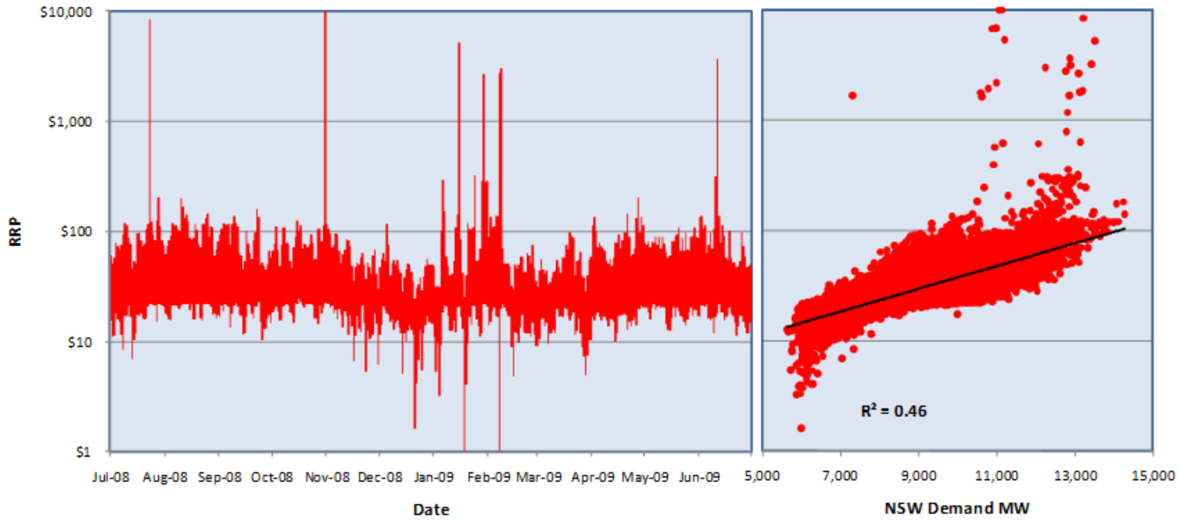
2.1 Wholesale energy market costs

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.

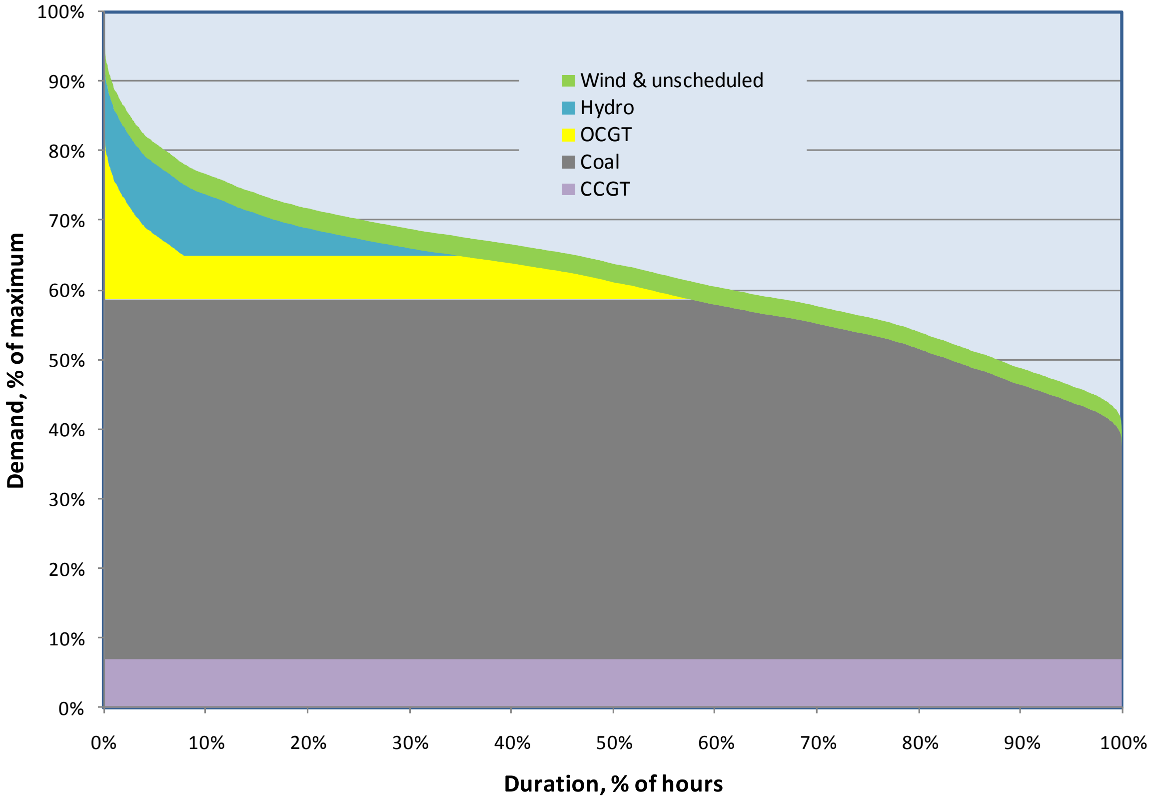
18 The cost of transmission losses is included in the LRMC estimate by MMA.

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.

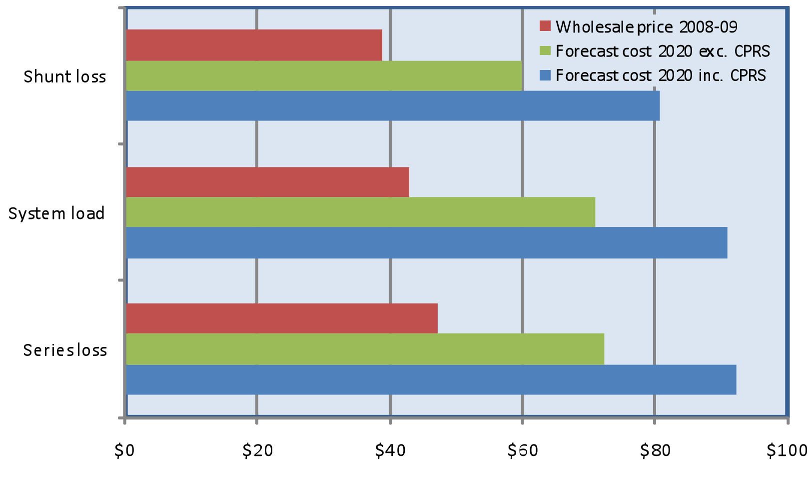
Table 5 - Long Run costs of energy supply, 2020

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.

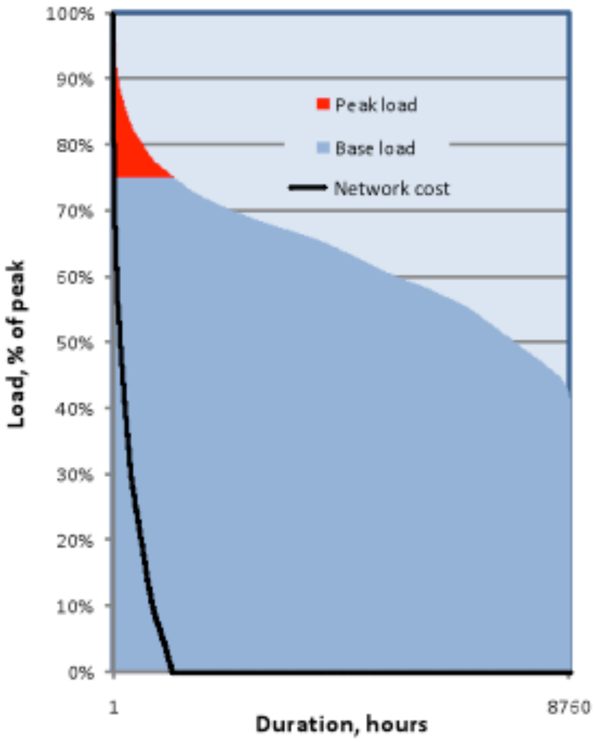
The first step in this process is to evaluate the LRMC of the network. The Net Present Value (NPV) of the future capacity augmentation investments and associated operating cost are spread over the associated increment in either demand or energy. Over a period of several years, for EnergyAustralia this 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.

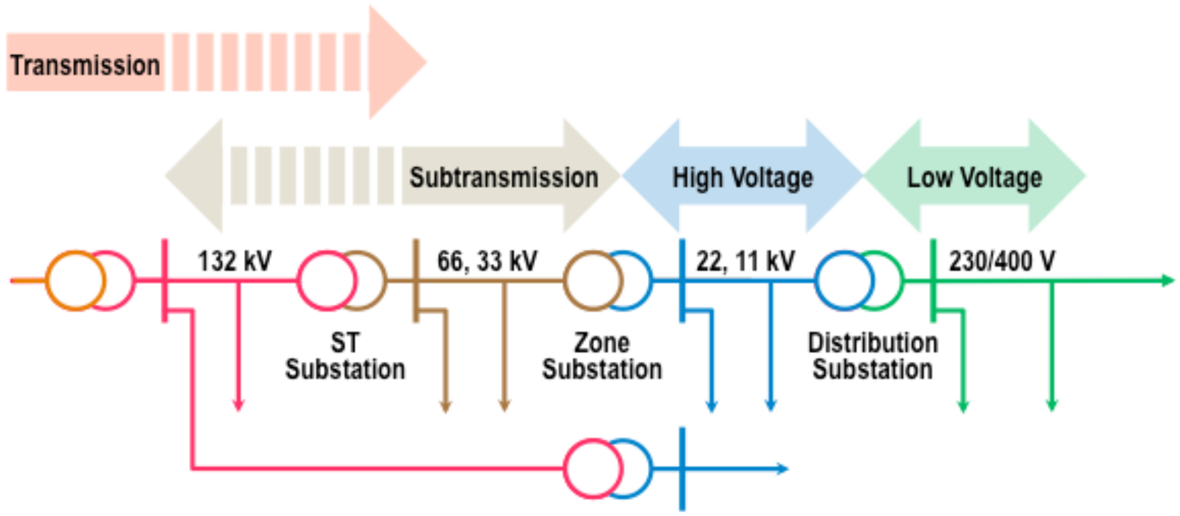
26 AER, Final decision TransGrid transmission determination 2009–10 to 2013–14, 28 April 2009, Table 9.5, p.122.

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

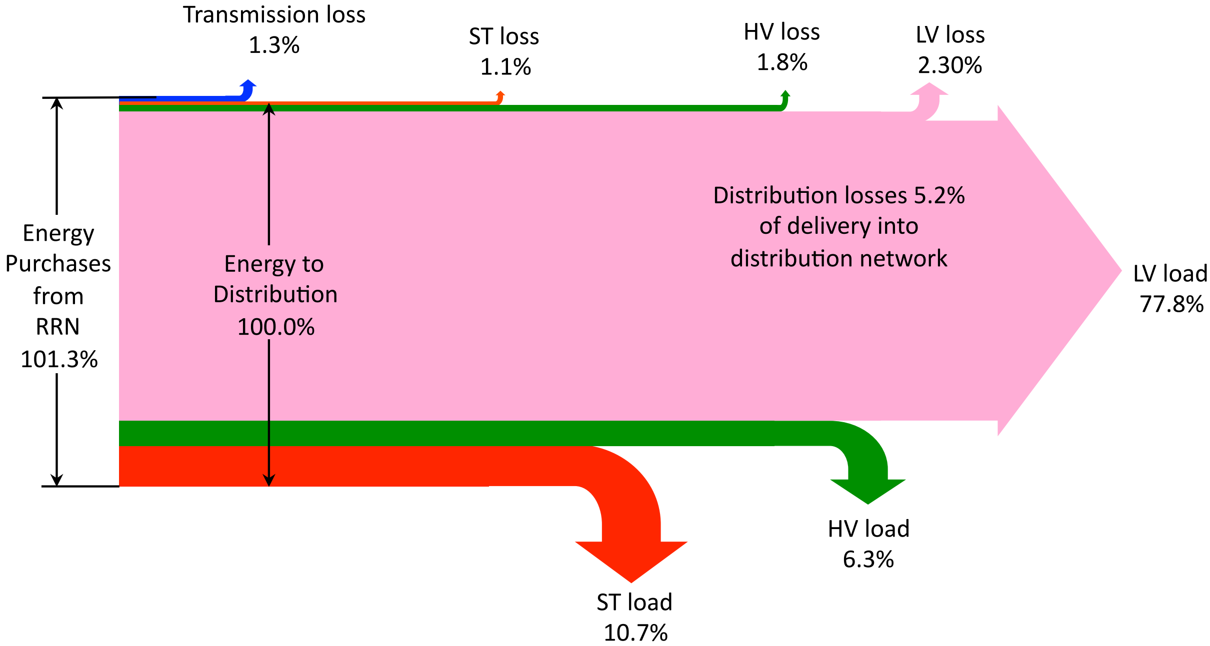
The cost allocation factors of Table 6 were also used in formulating Table 10.

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

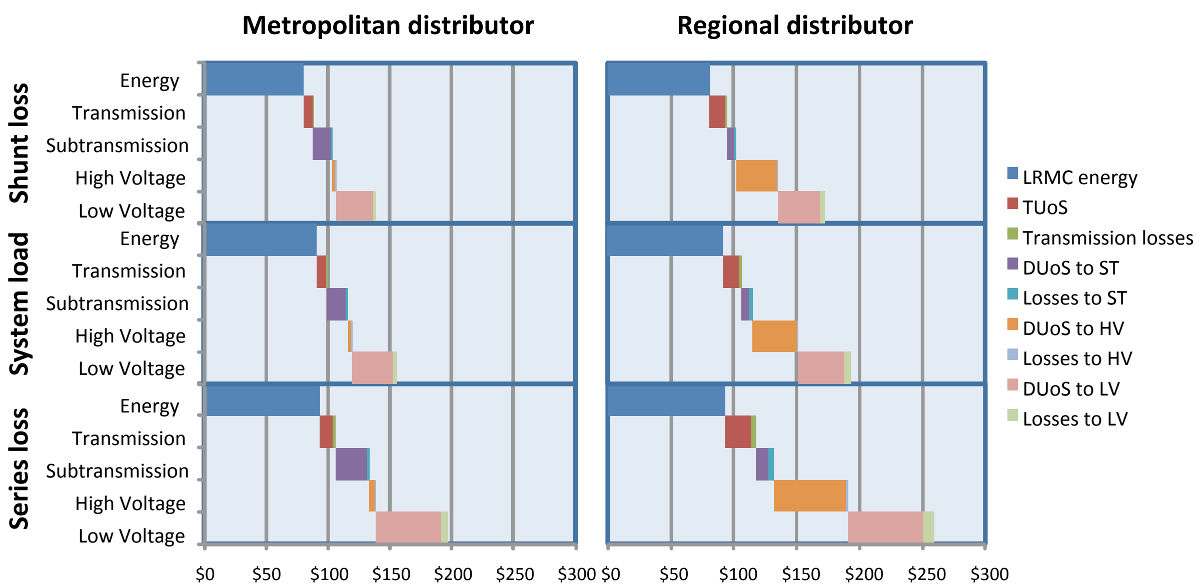
The elements described in sections 2 and 3 have been combined to yield the LRMC of supplying loads of different profile at different levels within the network. The outcome is shown in Table 12.

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

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MAXIMIZING THE PERFORMANCE OF ADDITIONAL RENEWABLE GENERATION IN AN ELECTRIC POWER SYSTEM

Dr N J Sligar, sligarj@sligar.com.au

SUMMARY

The transfer of electric power from a generation station to the customer incurs unavoidable losses due to the nature of the power system. The performance or efficiency of a power system is usually measured indirectly by its losses. This system efficiency can be maximized at the design stage. There is a strong economic, resource and environmental need to operate any electric power system as efficiently as possible.

The increasing use of renewable generation has added another layer of losses to existing conventional power systems from within the renewable generation resource itself. Most natural renewable generation, such as wind generators, consists of many units of 2-5 MW with output at low voltage assembled into groups via relatively long interconnecting cables to transformers to bring the voltage up to that normally provided by large conventional generators. This results in significant additional "assembly" loss rather similar to those in a conventional distribution network.

In the case of transmission/distribution networks there are regulatory or other requirements, such as equipment standards, which can be used to maximize efficiency of the cable and transformer components. The necessary financial drivers are present to promote high levels of efficiency. In the case of renewable generation there are no similar drivers. The only active commercial driver is minimum capital investment which results in cheapest cables and transformers, not contributing to overall system efficiency.

To maximize the efficiency of the overall power system consideration must be given to providing adequate drivers by requiring standards for equipment or regulation to ensure renewable generation equipment is at least at the equivalent level of efficiency as that for transmission/distribution.

At the same time there is a strong case to improve efficiency standards for both categories because of the known significant increase in the price of electricity over time. This initiative is essential whether in a monopoly or competitive electricity market.

In Australia there is a competitive market for electricity with delivery of power being regulated. Presently this regulation does not identify the nature or extent of losses or the overall efficiency of the power system. In any consideration of power system efficiency the first requirement is to identify the extent of losses or inefficiency so that suitable regulation can be applied.

1 INTRODUCTION

An electric power system is an elegant means of generating just enough electric power and transferring this power to a range of customers in a safe and stable manner.

This system consists of electric generators providing the electricity resources and a delivery system consisting of high voltage transmission and lower voltage distribution to the eventual customer.

The delivery of electric power to customers in present power systems involves some loss through inefficiencies in the delivery equipment. This consists mainly of high voltage transmission lines and distribution cables together with transformers to change the voltage to a value appropriate for the customer. Every one of these items can be provided at different levels of efficiency. More efficient equipment is more expensive and results in long term saving over the real life of the unit.

The International Confederation of Energy Regulators (ICER) represents 319 energy regulatory organizations throughout the world. It adopted the definition below for its major report:
"A description of current regulatory practices for the promotion of energy efficiency" June 2010

"Energy efficiency is the practice of reducing the amount of energy used without reducing the end-use benefits enabled by that energy.
Energy efficiency can be categorized in a number of ways including end-use efficiency and end-to-end efficiency."
Electric Power Research Institute (EPRI).

The advent of significant tranches of renewable generation adds a further set of losses on the generation side in increasing the line voltage from low voltage generators up to a value suitable for long distance transmission. There are regulatory drivers to induce owners to improve their system efficiency and minimize losses for delivery of electricity but not for renewable generation, resulting in less efficient equipment in this area.

Taking Australia as an example there are various components of the electric power system everyone associated with some losses. The Australian system is about 4500 km in length and voltage levels for high voltage is 220 to 500 kV, medium voltage 22 to 132 kV and low voltage is 240/415 V.

Recently there has been a significant increase in renewable generation connected to the power system. This consists of hundreds and eventually thousands of small, 2-5 MW generators separated over a broad area with connecting cables and transformers to bring the unit generated voltage of 600-700 V up to that normally from the previous 50 large generators. This is an assembly network rather like a distribution network in reverse with a corresponding additional loss of the same order.

The output from these units tends to be less than nameplate rating with a capacity factor varying between 25 and 35% with a few higher values, all of which is a function of wind variability or solar insolation.

2 ELECTRIC POWER SYSTEM GOVERNANCE

An electric power system may be operated under one of two quite different regimes. It may be operated by government as a monopoly in which case it executes government policy at the design stage of any facility. Government requirements as to system efficiency can be carried out at this stage.

In the second case the system is regulated by a government run competitive market regulator. In this case the government controls the operation of the power system by regulation, using this tool to execute its policies by providing drivers to move commercial organizations in the desired direction.

These drivers may be positive or negative. In a competitive market these drivers generally need to be positive to maintain commercial profit and consequent continuity of major investment.

3 POWER SYSTEM COMPONENTS

The main components of a power system are inter-connectors, either overhead lines or underground cables and transformers to change the voltage of a particular inter-connector. These two components contribute most towards the efficiency of the system. Switchgear and other ancillary equipment contribute little towards efficiency.

3.1 Inter-connectors

Inter-connectors may be above ground lines or below ground cables. Both have losses associated with livening up the line or cable and further losses associated with flow of power. These may have different losses depending on material of construction and cable cross section, both affecting resistance of the cable in addition to actual power flow.

3.2 Transformers

Transformers are made in a range of efficiencies with more efficient transformers being more expensive. In general the additional expense is far outweighed by the saving in power transmitted over the life of the equipment.

4 POWER SYSTEM EFFICIENCY

Power system efficiency is normally identified not as efficiency but as losses in the system. In a power system the generators supply a known quantity of electricity. At the same time customers utilize and pay for somewhat less electricity. The difference is the loss in electricity in passing through the various components of the system. Because customers change their requirements regularly and generators operate at different levels of generation this loss is dynamic and varies continuously.

Over a period of days or weeks or a year the loss can be quantified by comparing actual generation with customer consumption. Losses are therefore generally listed on an annual basis although their instantaneous extent can be estimated fairly well from installed equipment.

5 TYPES OF SYSTEM INEFICIENCY

Power system inefficiency or losses are made up of two components, fixed and variable which characterize most of the individual items of equipment within the system.

5.1 Fixed system losses

Fixed power system losses are associated with livening up the system of transformers and power lines irrespective of any actual electrical load they may carry. In some economies it is necessary to keep lines livened up to minimize social loss or removal of the cable itself or other equipment. Fixed losses are essentially a function of equipment such as cables and transformers.

Fixed power system losses can be reduced by purchasing more efficient equipment, higher efficiency transformers and lower resistance cable. The payback time for purchasing higher efficiency equipment is usually fairly short.

5.2 Variable system losses

Variable power system losses are those which vary with customer demand. These losses are essentially due to the interaction between transmission equipment and the customer load they are carrying.

5.2.1 Proportional loss

This component of losses is proportional to the load being carried by the interconnector. If the interconnector is carrying a light load most of the time then the fixed plus proportional losses make up a high component of the customers load. If the interconnector is carrying a high load then fixed plus proportional losses are a much lower proportion of the transmitted load. Keeping the load on an interconnector high is therefore to be preferred where possible.

5.2.2 Social loss

Social loss is a variable loss which occurs when customers receive un-metered electricity from the power system. This may arise from tampering with metering or laying induction cable aligned with the cable to induce power from the system. There is evidence of some social loss in Australia. It is a major problem in some other economies. The advent of “smart metering” may go some way to reducing this problem.

6 EXTENT OF SYSTEM INEFFICIENCY OR LOSS

Power system losses are generally reported annually. The medium voltage distinction between transmission and distribution is different for different economies generally depending on the amount of power transferred.

6.1 Transmission

In Australia transmission voltage varies from 220 kV to 500 kV depending on the State involved. Present large fossil fired generators terminal voltage is 25-35 kV transformed to the transmission line voltage appropriate to the State. The losses in raising voltage to transmission level, transmitting to distribution centres and reducing the voltage to 20-30 kV is about 3% of the transmitted power.

6.2 Distribution

The distribution level in Australia is 20-30 kV and reducing this for industrial and residential use at a nominal 415/240 V in Australia of the order of 5%. In some distribution centres the voltage may be higher, up to 132 kV in some cases. There is a general tendency to raise this voltage to cater for increased load density in cities.

6.3 Generation

Australia has provided strong government incentives to install renewable generation. This is being taken up by entrepreneurs with the likelihood that some thousands of MW will be installed over the next few years. These renewable generators are small, 2-5 MW and generate at a low voltage which has to be assembled into groups and transformed up to 25 to 35 kV to connect to a transmission system via a large transformer. This is not unlike a distribution network in reverse. The losses in such an assembly network are expected to be of the order of a corresponding distribution network and up to 5% of the power transmitted.

The following table provides an indication of transmission and distribution losses in a number of representative economies and changes over time. Numbers without dates are relatively recent.

Table

Typical Power System Losses

Economy	**Trans loss%**	**Dist. loss%**	**T+D loss%**
Australia	~3	~5	~8
India			32.5(2003)
India			16.6(2006)
Japan TEPCO			4.6
Taiwan Taipower			4.9(2009)
South Africa	4	6	10
USA			9.5(2001)
UK	2.6	6.4	9

7 IMPROVING SYSTEM EFFICIENCY

There are three components in improving power system efficiency, equipment quality, system operation and customer attitude.

7.1 Equipment quality

The first requirement is the quality and consequent efficiency of the various items of plant. In a conventional system with large fossil generators there are strong incentives to maximize efficiency driven by the cost of the fossil fuel used for power generation. This is the case whether the power system is a monopoly or a competitive market.

In the case of renewable generation there is far less emphasis on equipment quality because the “fuel” is provided at no cost. The primary driver, in the absence of regulation, is equipment capital cost. As a result there is a strong incentive to purchase cheaper lower efficiency equipment.

7.2 System operation

The second requirement is operation of the system with the minimum number of interconnectors consistent with system security. This will ensure that the lines in use are loaded to as high a value as possible, minimizing losses compared with useful current flowing to the customer.

In the case of renewable generation all interconnectors are maintained in service to maximize the collection of energy from wind or solar generators while the natural resource is available. This results in the interconnectors being more lightly loaded than equivalent large generator interconnectors with consequently lower overall efficiency of operation.

7.3 Customer attitude

Customer attitude is concerned with understanding the power system and how energy can be saved. Purchase of higher efficiency household equipment is assisted by upgrading the minimum standards for appliances which is in hand in Australia.

8 CONTROL OF SYSTEM EFFICIENCY

Power system efficiency is primarily controlled by drivers affecting the capital investment of the generator or transmission organization in appropriate equipment selection.

8.1 Government monopoly power system

In a government monopoly power system the maximization of system efficiency is a function of the internal policies of the monopoly. Power system and equipment efficiencies can be set at the design stage.

8.2 Competitive power market system

In a competitive market situation system efficiency can be controlled by suitable drivers being imposed on the participants by the market regulator requiring specific equipment standards or other regulatory measures.

8.3 Australian competitive market system

In the case of transmission and distribution in Australia the following regulation is applied to those organizations. Operators of tranches of the system submit proposals for the ongoing maintenance of their part of the system together with claims for extending their area to cater for new customer load. The regulator assesses these applications and grants the right to expend funds and recoup them via various charges.

In Australia the respective system inefficiencies or losses are not separately identified or officially considered in the application for such funding. A notional economic measure is used for the overall application for maintenance and network expansion. There is, in effect, an indirect driver to improve system efficiency. Improvements in system efficiency could be made by identifying the present system losses and making the reduction of these a matter for the application.

In the case of generation no such regulation exists. This was previously not of great concern because a single large generator generally utilized large transformers and the main driver for efficiency improvement was maximizing the output from the generator because of the cost of fossil resources.

The advent of significant tranches of renewable generation has changed this materially because the “assembled” generation potentially has significant assembly losses which could be minimized by equipment selection if suitable regulatory drivers or equipment standards were present.

9 COMPARISON OF GENERATION

To provide some sense of the difference between conventional generation and renewable “assembled” generation a medium sized coal fired unit is compared with the largest wind farm in the world. A medium sized coal fired unit with a capacity of 750 MW is considered. The maximum size of coal fired unit is about 1600 MW and there are generally four or six such units in a conventional power station.

9.1 Fossil generation unit

The 750 MW unit generates power at about 25 kV which is fed to the transmission system via a 25 kV to 220 - 500 kV transformer. This sent out power is measured leaving the power station. The subsequent lines and transformers to bring the voltage to a distribution level of 20-30 kV is about 3% in the national electricity market in Australia. A further 5% is lost in bringing this 20-30 kV power to 415 V for customer use.

A 750 MW unit would be expected to have an availability factor of 95% and could generate about 6,200,000 MWh in one year if required.

9.2 Wind farm generation unit

The present largest wind farm in the world is Roscoe in Texas USA. It has a nameplate rating of 781 MW made up of 627 separate wind turbines covering an area of 40,468 hectares. There are many interconnecting cable and transformers linking all these units with the local transmission system. The estimated investment is about USD 1b. The turbines are supplied by Mitsubishi, GE and Siemens. It has 209x1 MW Mitsubishi MWT-1000A units, 55x2.3 MW Siemens turbines, 166x1.5 MW GE ESS1.5 turbines and 197x1 MW Mitsubishi MWT-100A units.

Every turbine generates at 690 V three phase. Low voltage cables transfer this power in groups of about 28 generators to 690V to 34.5 kV transformers. These connect via intermediate voltage cables to a further bus and 34.5 kV to 115 kV transformers and eventually to the 345 kV transmission power system. Some wind generators have 690 V to 34.5 kV transformers in the base of the individual towers but still have considerable cabling to assembly points.

The 781 MW wind farm would be expected to have a capacity factor of about 31% which is the average for Texas. As a result it could generate about 2,120,000 MWh in one year if required.

In the case of the wind farm there are additional losses from throughput of the 690 V generators through interconnecting cable and transformers to reach the equivalent voltage at which output is measured on a conventional fossil fired unit. This assembly of renewable generation is rather like a distribution network in reverse with similar levels of loss. Distribution network losses in Australia are about 5% so generation assembly losses would be expected to be of the same order.

There is therefore a strong case to regulate such a generation assembly to at least minimize these losses. For instance a 1 MW wind generator generating at a capacity factor of 25% could produce about 38,000MW over its life of 20 years. If the installation is less efficient than it could be a loss in generation of 0.1% would amount to about 380 MWh of renewable power.

For a 1000 MW wind farm generating at a capacity factor of 25% its generation potential over 20 years is 380,000,000MWh. If the installation is less efficient than it could be a loss of 0.1% would amount to about 380,000 MWh of renewable power. It should be noted that there are proposals in process for greater than 10,000 MW of wind farms in Australia mainly as a result of Australian Government incentives.

Conventional methods of valuing losses over a significant time interval need to consider the expected increase in cost of power over time in any analysis.

10 CONCLUSIONS

Electric power systems have losses associated with their operation. There is a strong economic, resource and environmental need to operate these systems as efficiently as possible.

Adding renewable energy to an existing conventional power system results in additional "assembly network" losses, reducing the overall efficiency. The assembly network arises from the need to raise the renewable resource generation voltage to that used by conventional generators.

In the case of additional renewable generation no present standards or regulation exists to improve the efficiency of power systems containing significant proportions of these technologies with consequent waste of renewable power and the necessity to build additional renewable or fossil generation to cope with this.

This can be remedied by regulation or setting equipment standards depending on whether control is by government or a competitive market with a recognized regulator.

Existing inefficiencies or losses are not generally separately identified or form part of the considerations for approving additional funds for transmission/distribution maintenance and expansion. Such inefficiencies should be separately identified and addressed.

11 ACKNOWLEDGEMENTS

The assistance of the Copper Development Centre is gratefully acknowledged in the preparation of this paper.

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This paper was presented at the Conference of Electric Power Supply Industries (CEPSI) in 2010 in Taipei, Taiwan. More than one thousand participants took part from the major power generation and transmission sectors in Asia. This conference is held every two years in a different Asian economy.