Nuclear Power and the Western Australia Electricity Grid

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A mathematical model is used to show that the potential economic value of a nuclear-powered electricity generating unit in Western Australia is seriously limited by the small size of the electricity grid.

In June 1978 the Premier of Western Australia, Sir Charles Court, announced a desire for a nuclear-powered electricity generating unit in the state by the mid-1990s. Although there are no firm plans for nuclear power, the state government has since proceeded with preliminary evaluation of possible sites for such a unit.

In any decision concerning the introduction of nuclear power, a number of factors are relevant, including capital and fuel costs, electricity requirements and environmental effects, among others. One key factor in the case of a small grid system such as that of WA is the limited contribution that a large nuclear unit would make to the reliability of the grid electricity supply.

The primary aim of any electricity supply system is to provide an adequate supply of economical power with a high degree of reliability. The most common interruptions to supply arise from breakdowns in distribution and transmission facilities and from industrial disputes. The reliability of supply also depends on the availability of generating plant; here the focus will be on this aspect of the system.

An electricity generating system typically consists of a number of independent units. In WA these are fueled almost exclusively by coal and oil. Generating units could also, potentially, be fueled by gas or uranium, or powered by renewable energy flows in water (hydroelectricity), wind or the sun.

No single generating unit is 100% reliable: a unit does not generate power during periods of breakdown or planned shutdown. The fraction of time that power cannot be produced due to breakdowns is called the forced outage rate, and the fraction of time that power cannot be produced due to planned maintenance is called the planned outage rate. When the unit is capable of producing full power it is said to be available, whether or not it is being used.

When a unit is undergoing forced or planned outage, other units must be available to provide power. If too many units are unavailable simultaneously, there may not be enough power generated to meet the electricity load (demand) on the system, and 'loss of load' occurs: electricity supply to at least some users must be cut off. The probability that this will happen is called the loss of load probability (LOLP). LOLP is often used by power system planners as a planning criterion. For example, generating plant might be built to ensure that the LOLP be equivalent to 2 hours per year: LOLP = $2/8760 \simeq 2 \times 10^4$, a typical value.

Of course, a given LOLP for a generating system does not mean that any given electricity user will go, say, 2 hours per year without power. LOLP is mainly used for planning purposes; in this paper it is used in comparing different possible configurations of the WA grid. Even applied to an actual grid, loss of load may occur due to distribution or transmission failures, or strikes; only some users may be without power during a loss-of-load event; and the frequency of loss-of-load events varies from year to year due to the random nature of generator failures and unusual weather events. Each of these factors has been apparent during power shortages in New South Wales over the past year.

To the extent that the power capacity of any single unit is more than roughly 15% of the total capacity in the system, this unit's contribution to the total reliability of the system is reduced. This is because when the large single unit is not available, the rest of the generating plant has more difficulty in meeting the load than if the unavailable unit is small. In other words, the LOLP is dominated by the outage rate of the large unit. This rule of thumb is well known to power system engineers and planners.

To apply this rule of thumb, and thus indicate that contributions to reliability are potentially an important consideration in assessing nuclear-power in the WA grid, note first that in 1979/80 the generating capacity of the WA grid was rated at 1440MW (SEC, 1980a). A standard-sized nuclear unit has a rated power capacity of about 1000MW. Smaller units are also available, typically down to about 600MW, but at an increased capital cost per unit of rated capacity. Even if the capacity of the WA grid were tripled, the contribution that a 1000-MW or even a 600-MW nuclear unit would make to grid reliability could still be considerably short of optimal.

In the remainder of this paper a simple mathematical model is used to calculate the comparative economics of coal and nuclear-power in the WA grid, taking into account contributions to grid reliability. But first the likely WA electricity load in future decades will be discussed.

Electricity load

Power system planners have traditionally used an assumption of exponential growth in electricity load in making predictions. For

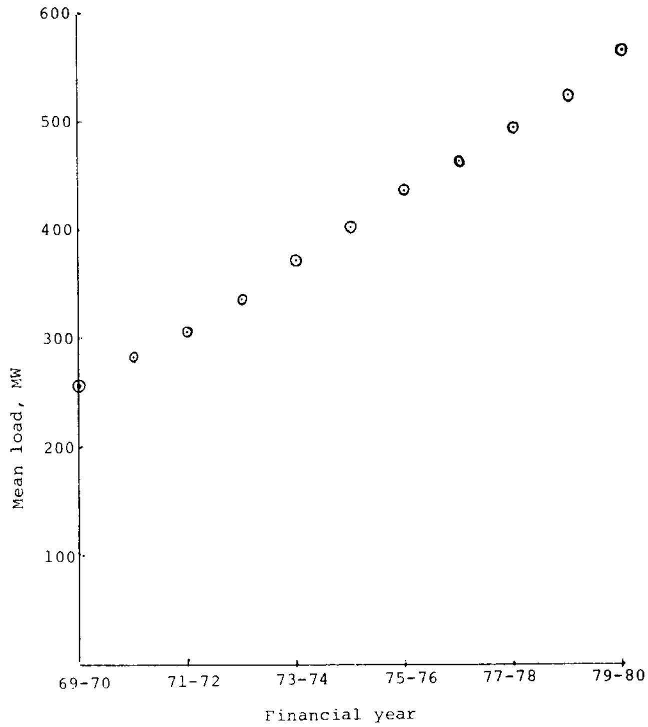

FIGURE 1
Mean electricity load in WA, in MW, for the 11 financial years 1969-70 to 1979-80. (The mean electricity load is the annual energy generated divided by 8760 hours.)

Station		Number of units	Fuel	Rated power (MW)	Minimum power (MW)	Forced outage rate	Planned outage rate	Availability
1		1	uranium	1000	0	0.15	0.15	0.70
	or	1	uranium	600	0	0.15	0.15	0.70
	or	2	coal	200	80	0.08	0.07	0.85
2		6	coal	200	80	0.08	0.07	0.85
3		4	coal	60	24	0.08	0.07	0.85
4		2	coal	120	48	0.08	0.07	0.85
5		2	oil	120	0	0.08	0.07	0.85
6		8	gas	20	0	0.08	0.07	0.85

TABLE 1
Generating units in three possible WA electricity grids with mean load $\bar{L}$ 1000MW. The first grid, in which station 1 is a single 1000-MW nuclear unit, has LOLP = 3×10^{-4}, the second grid, with a single 600-MW nuclear unit, also has LOLP$\times3\times10^{-4}$; the third grid, in which station 1 is two coal units, has LOLP = 6×10^{-5}.

example, official predictions for WA made in 1974 (Fuel and Power Commission, 1974) envisaged a mean load of 1000-MW in 1983 or 1986, under conditions of 'high' or 'low' exponential growth. (The mean electricity load is simply the annual energy generated divided by 8760 hours.) The inadequacy of this assumption in the WA case is apparent from a plot of the mean electricity load for the past 11 years (Figure 1). The failure of the exponential assumption has also been noted in other countries (Casper, 1976).

Power system planning is often based on an analysis of past and expected peak loads rather than mean loads. Actual peak loads are much more variable than mean loads on a year-to-year basis because of the strong influence of unusual weather conditions. The reason for using the mean load in the present context will be explained in following sections.

A comprehensive model for predicting electricity load would take into account factors such as patterns of electricity use in different sectors of the community, winter and summer peaks, and trends in fuel prices. Such sophistication will produce improved forecasts only if the underlying assumptions are correct, and the key assumption in many models has been that electricity load will grow exponentially at least in the short and medium term. The use of this assumption has led to gross overestimates of load growth in many parts of the world, with a consequent surplus of electricity generating capacity.

One referee of this paper suggested that for the data in Figure 1, 'there is sound logic for assuming at least a piecewise exponential growth'. Aside from the limitations of this assumption noted above, the normal approach of scientists is to apply Occam's razor and not introduce additional parameters unless it is clearly necessary.

For illustrative purposes it is assumed here that the mean load has been growing roughly linearly. Fitting to the points in Figure 1 a straight line

$$\bar{L} = aY + b, \qquad (1)$$

where L is the mean load and Y is the year counting from 1970, it is found (approximately) that a = 31MW/year and b = 248 MW. According to (*1*), L would reach 1000 MW in 1994 and 2000 MW in 2027.

Even equation (*1*) may give an overestimate of the load growth in WA in coming decades, for several reasons. An increase in the price of electrical power in real terms usually leads to a reduction in electricity demand, typically with a time lag of a few years (Taylor, 1977). Since the real price of electricity in WA has been increasing in recent years (Electricity Supply Association, 1980), it may be expected that load growth in WA in the next few years may fall below what might otherwise have been expected. Also, as electricity prices rise alternative options for end users become competitive, such as conservation and industrial co-generation. Finally, as electricity generation increases, environmental and resource limitations impinge at a disproportionate rate.

It is also possible that the introduction in WA of large-scale aluminium smelting, or other energy-intensive industries, could cause the mean load to exceed 1000-MW sooner than the mid-1990s. However, the latest indications suggest that the higher price of electricity in WA compared to eastern states will deter such developments, at least in the near term. In the following calculations, therefore, $\bar{L}$ = 1000 MW will be taken as an estimate of the highest mean load that is likely to eventuate in WA by the mid-1990s. As an extreme case, a mean load of 2000 MW is also considered.

The model
To meet the load $\bar{L}$ = 1000MW, three possible grid configurations are assumed. These are listed in Table 1. Aside from station 1, Table 1 gives a good approximation to how the WA grid will look in the near future, since grid expansion by the addition of further 200-MW coal-fired base-load units is currently proceeding. Future coal-fired units of 250MW or 350MW are also under consideration, but are not necessarily appropriate for the present calculations which assume $\bar{L}$ = 1000MW. In any case, changing a couple of the 200MW units in Table 1 to 250MW or 300MW does not change the results significantly.

The stations are listed in their merit order: i.e., the units in station 1 are used first to meet load; if this is insufficient the units in station 2 are used successively; and so forth until the load is met (see also *(i)* below). If not enough units are available at a given time to meet the load, loss of load occurs.

The calculation is carried out as follows. Starting with the full load distribution (which is referred to by power system engineers as the 'load-duration curve'), the available capacity of the first unit in the merit order is subtracted from the load distribution, giving the 'effective load'. (Since load and availability are random variables, 'subtraction' here refers to a convolution. Full mathematical details will be given in Martin & Diesendorf (1982). For a more descriptive account see Diesendorf, Martin & Carlin (1981).) At the same time the annual energy generated by the first unit is calculated. From the resulting 'effective load' the available capacity of the next unit is then subtracted, and so forth. When all units have been considered, the LOLP is given by the fraction of positive loads remaining in the final 'effective load'. All these calculations are carried out numerically on a mesh of 4-MW power intervals. (The size of the mesh has a negligible effect on the results.)

The method assumes that forced outages are independent, and that planned outages do not contribute to LOLP. The load distribution (equivalent to the load-duration curve) is in the present case derived from WA half-hourly load data, 1970-1979, with each year's load normalised to a mean $\bar{L}$ = 1000MW to simulate the target situation. (In addition the standard deviation of the load in each year is normalised to give an identical contribution to LOLP*.) This procedure is adopted instead of

*Since our interest is in the effect on LOLP of alternative *plant*, it is desired that the *load* for each year give an identical contribution to LOLP, denoted by p. To meet this condition, each half-hourly value L of the load

TABLE 2
Total electricity generating costs in the WA grids in Table 1 under a number of assumptions favourable to nuclear power, in A$M per year, for a variety of cost coefficients. (Interest during construction accounts for 25% of the capital costs.)

Cost set	Capital cost coefficients ($/kW) 1000-MW Nuclear	600-MW Nuclear	Coal	Oil	Annual charge rate	Fuel cycle cost coefficients (¢/kWh) Nuclear	Coal	Oil	Total costs (M$) 1000-MW Nuclear	600-MW Nuclear	Coal
1	187	267	80	27	10%	1.2	1.7	4.5	456	438	331
2	187	267	120	27	10%	1.2	1.7	4.5	523	505	414
3	133	187	80	27	10%	1.2	1.7	4.5	402	390	331
4	240	333	80	27	10%	1.2	1.7	4.5	509	478	331
5	187	267	80	27	5%	1.2	1.7	4.5	289	285	242
6	187	267	80	27	15%	1.2	1.7	4.5	622	590	419
7	187	267	80	27	10%	1.2	2.5	7.0	485	480	403

normalising to a peak load because LOLP depends on a considerable portion of the load distribution in the neighbourhood of the peak load — i.e., loss of load may occur at other than annual record peak-load times. In any case, the results obtained using any single year's load distribution are almost identical to those obtained using the distribution for all the years 1970-1979.

The LOLP for the configuration without station 1 is 2×10^{-3}. As noted in the caption to Table 1, the 1000-MW nuclear unit reduces the LOLP to 3×10^{-4}, as does the 600-MW nuclear unit, while the addition of two 200-MW coal units reduces the LOLP to 6×10^{-5}. In other words, the addition of two 200-MW coal units provides a greater improvement in the reliability of supply of generated electricity than does a single 1000-MW or 600-MW nuclear unit. This conclusion depends only on the rated powers of the units and on their forced outage rates. (For references on outage rates, see (*h*) below.)

Economics

The comparative economics of a nuclear unit versus the two coal units (which provide an equal or greater contribution to grid reliability) can be assessed only after capital and fuel-cycle costs are assigned to all the units in the grid. There have been many comparisons of the economics of electricity generation by nuclear power and by coal. The calculation here is meant to illustrate the impact of the small grid size on the competitiveness of nuclear power.

The annual economic cost of a grid configuration is the sum of annualised capital costs for each generating unit, plus the sum of fuel cycle costs per unit of energy times the energy generated in a year by that unit. The energy generated by each unit is calculated probabilistically using the WA load curves and the availability of each unit. Calculations have been performed for a wide range of cost parameters. Representative results are presented in Table 2. (All costs are in 1980 Australian dollars.) Cost set 1 is based on a 'standard' set of parameters (subject to the following discussion), and sets 2 to 7 are variants.

The assumptions involved in the calculation are now described.

(a) Capital cost of nuclear plant

There is considerable debate on this topic. The 'standard' value used here for a 1000-MW nuclear unit is a direct capital cost of $1400/kW. Values of $1000/kW (cost set 3) and $1800/kW (cost set 4) are used to illustrate the effect of different nuclear capital costs. The lower value is similar to values used by the WA State Energy Commission and by the WA government.

There has been strong criticism of some of the methods of calculation of the historical costs of nuclear power and of the claimed costs themselves (Bupp & Derian, 1978; Sweet, 1978; Jeffery, 1980). Future costs are highly uncertain and notoriously difficult to estimate (Lovins, 1979). When full account is taken of capital costs of all parts of the nuclear fuel cycle (such as reprocessing and decommissioning), research and development costs, the higher cost of installing a nuclear unit in WA, nuclear power's more rapid rate of capital cost escalation compared with coal, and other factors, even the figure of $1800/kW may be quite generous to nuclear power.

Economies of scale are considerable in nuclear units, and hence the capital cost of a 600-MW unit is much greater than 60% of the capital cost of a 1000-MW unit. A 'standard' direct capital cost of $2000/kW is used for the 600-MW nuclear unit.

(b) Capital cost of coal plant

The 'standard' value used here is $600/kW, which is close to current WA costs. The 50% higher value of $900/kW (cost set 2) is used to illustrate the effect of a possible escalation in the real cost of coal plant capacity.

(c) Fuel cycle costs of nuclear power

The value adopted here for the total fuel cycle, operation and maintenance cost for nuclear power is 1.2¢/kWh. This is rather more than the value of 0.9¢/kWh (in 1977 US dollars) reported by Rossin & Rieck (1978), but rather less than the values reported by CEGB (1980) (0.83p/kWh) and SECV (1981) (1.68¢/kWh). If the latter value were the appropriate one, nuclear power could not possibly compete with coal in almost any part of Australia. Hence the value assumed here may strongly favour nuclear power.

(d) Fuel and operating costs of coal plant

For the fuel and operating costs of coal plant, two values are assumed: 1.7¢/kWh and 2.5¢/kWh. The first of these is about equal to current coal fuel, operation and maintenance costs in WA; the higher value (cost set 7) is used to illustrate the effect of rapidly escalating real coal costs or the use of imported coal.

(e) Capital and fuel costs of peak plant

The capital cost of oil or gas turbine plant is much lower than for base-load coal plant, while the fuel costs are much higher. The values adopted here are in the right range. Sensitivity tests show that changing these values makes no difference in the results.

(f) Charge rate

To convert total capital cost to an annual cost, a standard figure of 10% for the annual charge rate* has been used. Cost sets 5 and 6 illustrate the effect of using charge rates of 5% and 15%.

(g) Interest during construction

Capital cost figures for all units have been increased by one third to take into account interest during construction. Since nuclear

is replaced by a value L' given by

$$L' = \bar{L} + a(L - \bar{L}).$$

The value a for a given year is chosen so that the distribution of values L', when convoluted with the availability, gives p. In all cases a is very close to 1, and the renormalisation has only a trivial effect on the results.

*The 'annual charge rate' is defined here as a/P, where a is the annuity which if paid once per year and placed at real interest rate i gives rise to an accumulated capital and interest after n years of P. The charge rate equals $i/(1-(1+i)^{-n})$. The term $(1+i)^{-n}$ in the denominator essentially corrects the units take longer to construct than coal units, interest during construction for nuclear units normally would be a larger fraction of the capital cost than for coal units. Hence, the assumption used here about interest during construction favours nuclear power.

(h) Availability and outage rates
The availability assumed for the nuclear unit, 70%, agrees with Rossin & Rieck (1978), but is higher than that indicated by the data presented by others (e.g. Komanoff, 1980). The 85% availability assumed for coal plant is reasonable for WA, since WA units high in the merit order achieve over 80% capacity factor, and the availability is always higher than the capacity factor. It is assumed that outages are divided equally between forced and planned outages.

In the computations, it is assumed that no unit is undergoing planned outage when a loss-of-load event occurs. The larger a unit is, the less likely this assumption is to hold, especially when planned outages are of substantial duration as is common for nuclear plant. Hence the LOLP calculation above probably favours nuclear power in its assumption that planned outages do not contribute to loss of load.

(i) Minimum power output
It is assumed that the coal units, when available, cannot be regulated below 40% of their rated capacity, whereas the peak and nuclear units can be regulated to zero power output with no penalty. Power regulation is important in periods of low load; when the minimum power output of all available plant is greater than the load, the excess energy generated is wasted. The assumption of a minimum power output equal to 40% of the rated capacity for coal plant agrees with WA operating limitations.

In principle, nuclear units can be run below rated power with little penalty, since to a good approximation there is no increase in fuel cycle cost per unit of energy generated when running below rated power (Glasstone & Sesonske, 1967), although at zero power output energy is wasted through fission product decay and, as well, costs of operation do not decrease when units are run below rated power. But in practice, nuclear units when available are only very seldom run below their rated power. Nuclear units are almost without exception assigned to the top of the merit order in electricity grids around the world, and often as a matter of policy are not operated below rated power to follow load variations.

This suggests that there may be unstated operational reasons for not utilising the stated flexibility (George, D.W., pers. comm.) of power output from nuclear units, or perhaps a reluctance to use this flexibility and thus reduce the total electrical energy generated by nuclear units and increase the total energy generated by coal units (hence affecting statistics on total costs per unit of generated electrical energy, to the detriment of nuclear power). Since running coal units below rated capacity can result in a significant energy and hence cost penalty, at times when available nuclear and coal capacity is greater than the load it may be economical on occasion to reduce nuclear rather than coal power output, contrary to established practice, especially when the fuel-cycle cost differential between the two is not great.

For these reasons, the assumption here that nuclear units may without penalty be regulated to zero power output is very generous to nuclear power. Calculations show that dropping this assumption adds about $56M per year to the total electricity generating cost of the grid in Table 2 with a 1000-MW nuclear unit, and about $23M per year to the cost of the grid with a 600-MW nuclear unit.

(j) Planning margin
Small or medium-sized units can be planned, built and brought on line as increases in load make this necessary. A large nuclear unit requires a very long lead time: if it is delayed, power shortfalls may occur, while early completion can result in surplus capacity. If expected load growth does not eventuate, the economic penalty can be enormous. The present calculation, by not taking into account these costs and risks involved in dynamic system growth and planning, favours the nuclear option.

(k) Spinning reserve
When a given unit fails, other units must be available to provide power at short notice. The fuel costs of this 'spinning reserve' are not taken into account in the calculation. Since the required reserve for a configuration containing a nuclear unit is substantially larger than for an equally reliable configuration without a nuclear unit, the calculation favours nuclear power in this respect also.

Conclusion

The results in Table 2 show that either a 1000-MW or a 600-MW nuclear unit is economically less valuable in a WA electricity grid with a mean load of 1000MW than two 200-MW coal units (which provide a greater contribution to the reliability of the electricity supply). This is the case even when assumed costs are quite favourable to nuclear power — indeed perhaps unrealistically so — and in spite of several other assumptions of the model which favour nuclear power. These results illustrate the large economic penalty suffered when a large electricity generating unit is placed in a small electricity grid.

This particular penalty would obviously be reduced if the grid were larger or the nuclear unit were smaller. When the calculation is carried out assuming a WA grid with a mean load of 2000MW and cost set 1, the grids with nuclear power have total costs of $737M and $724M compared to a total cost of $623M for a more reliable grid without nuclear power*. Thus even with a mean load in excess of that predicted by official forecasts (SEC, 1980b), this calculation indicates that nuclear power would still not have an economic advantage over coal. If some of the cost parameters are altered in favour of nuclear power, this conclusion is not changed dramatically; but in such cases an evaluation of the nuclear option would require a more detailed study in which the assumptions favourable to nuclear power in the present calculation are replaced by more realistic ones.

On the other hand, in grids significantly smaller than the WA grid, the economic penalty imposed by a large nuclear unit is even greater. There have been proposals to build a nuclear-powered electricity generating unit in the Northern Territory, whose current *peak* electricity load is less than 100MW. Under even the most optimistic assumptions, such a development would almost certainly be highly uneconomic compared to alternatives.

Since the severe diseconomies of a large unit in a small grid are well known to power system engineers, it might be concluded

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interest rate (or discount rate) for the finite lifetime of the asset in question. The following are some sample conversions.

charge rate	*n*	*i*
5%	20	0%
	30	2.8%
10%	20	7.8%
	30	9.3%
15%	20	13.9%
	30	14.8%

*The grid assumed for the calculation with $\bar{L}$ =2000MW is as follows: station 1, one 1000-MW nuclear unit *or* one 600-MW nuclear unit *or* two 250-MW coal units; station 2, six 250-MW coal units; station 3, six 200-MW coal units; station 4, four 60-MW coal units; station 5, two 120-MW coal units; station 6, two 120-MW oil units; station 7, sixteen 40-MW gas turbine units. LOLP with either nuclear unit is 1.7×10^{-4}, and with the two coal units is 5×10^{-5}.

that the basis for any plans for nuclear power in WA within the next two decades are political rather than economic. In the case of the Northern Territory this conclusion is even more apparent. Indeed, even in large grids the advantages of large electricity generating units may not be as great as commonly believed. (Abdulkarim & Lucas, 1977). (It can be argued that the basic motivations behind many large-scale power projects are vested corporate and bureaucratic interests and an unquestioning belief in the value of any large industrial development (Saddler, 1981).)

Although nuclear power has been compared with coal in this paper, in practice electricity supply planning should take into account a much wider range of options, including increasing the efficiency of energy use, industrial co-generation, the use of renewable power sources, load modification, and the possibility of alternative ways of satisfying needs now served by electricity. Such a wider analysis would need to go beyond the narrow capital and fuel-cycle costs used here and include environmental, political and social factors.

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