# Electricity Generators and the Deregulated Market

## A hole in the pool?

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## The physics of power generation

Electricity is produced, distributed, and mostly used by exploiting the interaction of magnetic fields and electric currents. When an electrical conductor moves through a magnetic field, a potential is generated in the conductor and, if the conductor is part of a complete circuit, a current will flow. Whenever a current flows it produces a magnetic field in the opposite direction to the field causing an electrical potential to develop, and the interaction of the two fields results in a force tending to retard the movement of the conductor.

An appropriate arrangement of conductors on a rotating shaft (the rotor) running between a fixed set of conductors (the stator) can be used as a generator by forcing the rotor to turn, or as a motor, by causing the fields in the stator to turn, driving the rotor in front of them. When an electric motor is connected to the power supply, it can be turned into a generator simply by spinning it (or in the case of a synchronous machine, trying to spin it) faster *than* the rotational speed of the power supply. When the driving force is removed, a generator becomes a motor and continues to turn until the it is disconnected from the power system.

Electrical transformers consist of two sets of windings on a single stator: changing the current flowing through one set induces a voltage in the other. Transformers are used to convert the voltage between that convenient for generation (from 415 v to 16.5 kV, depending on the generator) to that suitable for long-distance transmission (330 or 500 KV in SE Australia). Intermediate voltages are used for distribution to district substations, street transformers, and houses.

Australian power systems are based on alternating current reversing its direction of flow 100 times per second, and completing a cycle in a fiftieth of a second for a frequency of 50 Hz. When the voltage changes the current will tend to change, which will force all the magnetic fields associated with that current to change: this will tend to slow down the rate at which the current changes causing it to "lag" the voltage. Engineers use vector algebra to decompose the current flowing in an AC circuit into "active" and "reactive" power, or watts and vars. Vars (volt-amps reactive), or more particularly the reactive amps, cause heating in the transmission system and the generators and reduce their capacity to transmit and generate active power.

In the limit, a transmission system could consume so much reactive power that its thermal capacity would be wholly used up, and no useful power could be transmitted at all. The reactive power contributes to the voltage drop along a transmission line, with the result that there is a maximum economic length for any AC transmission system. This rises with the operating voltage, but for very long overland routes and for undersea cabling it is economic to convert the power to direct current for transmission, or ship it in the form of coal, oil or gas for local generation.

In a typical power system there are a number of generators and loads connected to various points on a transmission network. Except in emergencies (when "load shedding" may be needed to preserve the stability of the system) the generating stations have no control over the loads: people switch on lights or start plant, and automatic equipment turns itself on and off, without any prior arrangement with the generating plants.

Each generator has two main controls, the exciter voltage and the throttle. The exciter voltage setting determines the voltage at the output bus bars, and effectively controls the share of the reactive load that a particular generator will take up. The throttle determines how much power is fed into the generator, and apart from (very slight) changes in rotational inertia, how much active power will come out. Both the exciter voltage and the throttle *can* be set to given levels manually, or they *can* be made to operate automatically in response to voltage and frequency changes at the station busbar. For a system to be stable, at least one generator must have its throttle on automatic (meaning that it will pick up changes in load) and at least one generator must have its regulator on automatic (so that it will pick up changes in reactive load).

## The Second Law

"You get nothing for nothing and damned little for five cents."

The main points of the Second Law of Thermodynamics were worked out by Carnot in 1824, but his work was ignored until was rediscovered and published by William Thompson, Lord Kelvin in the mid nineteenth century. Camot demonstrated that there was an absolute limit to the theoretical efficiency of an engine that converted heat to mechanical energy, given by the formula:

$$\eta = \frac{T_h - T_l}{T_h} \quad \textit{where} \quad \begin{array}{l} T_h \text{ is } \textit{the absolute temperature of the source} \\ T_l \text{ is } \textit{the absolute temperature of the sink} \end{array}$$

$T_h$ is limited by the fact that steel is not very useful at temperatures much over **500°C** and even advanced materials don't perform well at much over 600°C. $T_l$ cannot be lower than the ambient temperature, and in practice must be some way above it. The Second Law sets an absolute limit to the thermodynamic efficiency of every type of power generating plant.

The thermodynamic limit for steam powered generating plant is about 58 per cent, but the practical difficulties of capturing all the heat from the flame, and the capital cost of chasing the last few efficiencies, limit the most efficient black coal fired steam generating plants to a gross thermal efficiency (GTE) of about 40 per cent. The technical difficulties of burning brown coal reduce the GTE of brown coal fired stations to a range 35–38 per cent. This is acceptable when, as in the Latrobe Valley, the stations are adjacent to large supplies of brown coal with no other economic value and so available at a very low price.

Gas turbine plant is designed and built to aircraft operating standards and achieves thermodynamic efficiencies of up to 25 per cent, quite close to its theoretical limit, but this is offset by the need to burn very clean, and relatively expensive, fuel. Only about 30 per cent of each tonne of Latrobe Valley brown coal actually burns; about 60 per cent is water, and the rest a mixture of salt and dirt. Burning the stuff at all is an engineering triumph; feeding it directly into a gas turbine is not very rational.

## Types of generator

The types of generating plant connected, or likely to be connected, to the Australian grid include:

- Diesel sets, although their expensive fuel and relatively small capacity generally means that diesel is only used in remote areas;
- Back-pressure turbogenerators, industrial cogeneration equipment without a condenser, with the exhaust steam being used for process heat; these can only operate when connected to a grid for frequency stabilisation;
- Bypass turbogenerators, industrial cogeneration equipment with a small condenser, with bled steam being used for process heat; has stand-alone capability but can also be connected to the grid; not economic to operate when the associated plant is shut down;
- Intermediate load steam powered generating plant, with the boiler configured for rapid heat raising rather than maximum thermal efficiency and the turbogenerator likewise configured to respond to rapid load changes; often gas-fired (as at Newport, Victoria); can be on-line about 30 minutes after a cold start;
- Base load steam powered generating plant, with the boiler and condenser configured for maximum thermal efficiency; takes several hours to come on line from a cold start and a matter of hours to change from light to full load and *vice versa.*
- Gas turbine "peak chopping" plant, usually run on gas but can be oil-fired and (at experimental level) can be associated with coal gasification; relatively low thermal efficiency but can come on line to full load in a matter of seconds,;
- Combined Cycle Gas Fired, a gas turbine with the exhaust gases entering a steam raising system and generator of the intermediate-load configuration; can achieve a very high thermal efficiency and is relatively "greenhouse friendly"; no plants of this type are yet in service in Australia;
- Integrated coal gasification combined cycle, a technical daydream at the moment, but in theory capable of realising the high efficiency of a combined cycle gas fired plant while using low cost coal.

Capital costs per kilowatt run from around $500 for a plain gas turbine to $2000 for a black coal fired base load station and $2500 for a brown coal fired base load station.

Fuel costs range from 0.28 cents/Kwh for brown coal through 1.1 cents/Kwh for NSW black coal to 5–7 cents/Kwh for gas turbine and diesel sets. Specific geographical circumstances may bring the price of natural gas below its natural relationship to oil from time to time, but these will become more rare as Australia's natural gas grid is completed.

## Integrated system operation

When a generating system is operated as a single entity, the stations are ranked in order of increasing variable cost, and subject to system stability considerations, allocated load in this order. Intermediate and peaking plant will be called on as required to smooth the load on the base load stations, enabling them to maintain peak efficiency and minimising the stresses caused to the plant in these stations by sudden load changes and by unnecessary stops and starts. Base load stations whose output is not needed tend to be operated continuously as "spinning reserve" to pick up load from any loaded set that fails and thereby avoid load shedding.

The objectives of load management in an integrated system are to minimise the total fuel cost and to maximise the life of the most expensive plant. Power is supplied to the grid at an administered price, determined by a mixture of political and economic considerations. Where the utility is state-owned in a developed country, plant is likely to be ordered and commissioned in advance of demonstrated demand, since voter reaction to blackouts is likely to be severe. Where the utility is a regulated private concern, as in most of the USA, the utility will delay ordering new equipment for as long as possible, hoping that blackouts and brownouts will lead to pressure on the regulating agency to approve a rate increase "to justify new plant".

When the regulating authorities set maximum prices for an integrated generating system they aggregate the capital and fuel costs and set a price that recovers these costs, with an appropriate rate of return, over a normal year's operating cycle.

## The Pool

Under the competitive pool system an independent authority allocates load to the various generators based upon a quoted rate per Kw at each half-hour during the day; the lowest price quote gets the first tranche of load while small variations are split between the last station called into service and plant allocated "spinning reserve" and "Mvar control" duties by an entity called the Auxiliary Services Manager.

The pool price for each half-hour period is determined by the rate quoted by the last generator called on for service, and every generator that contributed power to the pool is paid at this rate; equally, users pay the pool manager at this rate for any load that they draw. If there were two stations on-line B (for Base) quoting 3 cents/Kwh for up to 1000 Mw, and P (for Peak) quoting 6 cents/Kwh, as long as the load was below 1000 Mw station B would supply the whole load and the price would be 3 cents. As soon as the load rose above 1000 Mw station P would be called in, and the pool price would rise to 6 cents/Kwh.

As well as deals made at the "spot" price from the pool, heavy users can negotiate "bilateral" deals with a generator (or any sufficiently foolhardy intermediary) for electricity at a guaranteed price. At times when the pool price exceeds the guaranteed price the generating company or other intermediary would make up the difference, while when the pool price is below the guaranteed price the difference would be credited to the generating company. When the consumer end of a bilateral deal is unable to absorb the contracted load the excess can be sold back into the pool, reducing the consumer's obligation to the supplier. Bilateral deals can either be continuing or for a specific future period. Such specific deals are referred to as "futures" and it is expected that they will be traded on a secondary market. In the UK, the average guaranteed price is roughly twice the average pool price, for reasons which will be discussed below.

The pool system has been designed on the basis of a (disproved) economic theory that says that "competition" produces the best possible outcome. "Competition" can be "perfect" or "imperfect"; in practice all competition is imperfect, since there is never an infinite number of suppliers. In Victoria it is proposed to divide the generating system into five or six companies, who are expected to engage in a desperate price war in order to get load for their expensive generating assets. In the UK no such price war materialised and electricity prices are jammed firmly against the regulated maximum; it has been suggested that this is because the two biggest power companies controlled 30 per cent of the market each, while in Victoria the biggest company will be limited to 27 per cent of the market.

## A cold bath

Most electricity users need their power supply to be continuously available. A few heavy users have some items of plant and some processes that are suitable for an interruptible supply, but in general people want their lifts, lights, air-conditioning systems, trains, trams, and machinery operating continuously. They know that the pool price is often relatively low, but that it may also jump very high, leaping by a factor of four or more. They also suspect, with reason, that the pool price may be very artificial, very much at the mercy of the generating companies.

Typical users will, therefore, negotiate a long-term deal, either directly with a generating company, with a distributor or with another intermediary for electricity at a guaranteed price. On the precautionary, or bad news principle they will contract for a guaranteed supply *greater* than their expected average demand, possibly even approaching their maximum demand. They know that they will receive a credit for any unused power at the current pool price, but the cost of any overpayment will be set against the serious consequences of a supply interruption and the risk of being called upon to pay very high prices for supply above the contracted level.

The generating companies will be eager to oblige these users, offering guarantees for their generating equipment's whole sustainable production level, or even a little more if they employ good statisticians. Their best strategy will now be to bid low enough to keep the pool price low as long as actual demand has not reached contracted demand, and then push the price as high as the regulator will allow as soon as actual demand passes contracted demand.

Reverting to our previous example, station A might have underwritten bilateral contracts for 800 Mw at 5.9 cents/Kwh. They bid 800 Mw at 3 cents (not worrying if they are undercut and not scheduled, because they can earn $23,200 per hour without even switching the station on), their next 100 Mw at 14 cents and their last 100 Mw at 20 cents. *B* will observe this behaviour and bid its 100 Mw capacity at 13.95 cents, getting the same 20 cents as B as soon as the load moves into the peak zone.

Using the SECV's 1993 load profile, this strategy produces an average price/Kwh of 6.6 cents for B and 15.4 cents for P, comparing quite favourably with their assumed fuel costs of 0.28 cents and 6.5 cents respectively. P gets on line for 4000 or so hours per year, even though load peaks only last for 1000 hours or so. B lets P get the extra hours to discourage any extra-keen pricing and ensure that the pool price rises substantially as soon as *B's* contracted load is exceeded. Both *B* and P earn a return of around 11% on their capital.

This strategy reproduces two of the effects noted in Britain following privatisation:

(1) The average price paid is substantially higher than the average pool price, because the main supply to the pool is unwanted excess energy being returned by contracted buyers. The average price is higher than the HT supply tariff would have been with the same equipment operated as an integrated network;

(2) Gas is used for far more of the intermediate load, and coal for far less, than would be considered technically optimal, and some intermediate-load service is handled by base-load stations, technically undesirable but commercially very rewarding.

## An economic model

### A single generating authority

Consider an electricity distribution network with a demand consisting of a base load and a sinusoidally varying peak load: the amplitude of the variation is $a$ and the load at time $t$ is given by (2).

$$d = 1 + a\sin t \tag{2}$$

If results are required for more complicated periodic demand patterns the complex pattern can be decomposed into a series of components of the form (3) by Fourier analysis, partial answers recovered for each term, and the results summed.

$$d_i = a_i \sin it \tag{3}$$

The supply authority (or in the absence of an authority, market forces) arrange for this demand to be met by a combination of base-load plant with capacity P and gas turbine plant with capacity 1+a–P. The per-unit capital cost of the base load equipment is $C_c$ and the variable cost $V_c$, similarly the costs of the peak load equipment are $C_g$ and $V_g$. The appropriate risk-weighted rate of return is $\rho_1$ and the appropriate amortisation/depreciation rate is $\rho_2$. Labour costs, which are taken as constant across any period in which the plants actually operate, are $L_1$ and $L_2$ respectively; in the numerical examples below the labour cost of the peaking equipment is set to zero, since such equipment is usually operated either automatically or by remote control from a continuously manned network control centre. Per-period fixed costs are given by (4).

$$\begin{aligned} f_c &= (\rho_1 + \rho_2)C_c + L_c \\ f_g &= (\rho_1 + \rho_2)C_g + L_g \end{aligned} \tag{4}$$

It is easy to show that, when the plant is loaded according to its variable cost ranking, the peaking plant will operate for time fraction $w$ and generate $\lambda$ units of power where $w$ and $\lambda$ are given by (5).

$$w = \frac{1}{2} - \frac{1}{\pi}\operatorname{asin}\left[\frac{P-1}{a}\right]$$
$$\lambda = \frac{a}{\pi}\left(\sqrt{1-\left[\frac{P-1}{a}\right]^2} + \frac{P-1}{a}\left(\operatorname{asin}\left[\frac{P-1}{a}\right]-\pi\right)\right) \tag{5}$$

Total cost T is given by ***(6)***

$$T = Pf_c + (1+a-P)f_g + (-\lambda)V_c + \lambda V_g \tag{6}$$

(6) can be differentiated, set to zero and solved for $P$, as in ***(7).***

$$P = 1 + a\cos\left[\pi\frac{f_c-f_g}{V_g-V_c}\right] \tag{7}$$

***(7)*** is the optimum base load capacity that would be installed by a social planner blessed **with** perfect foresight and a magic wand that created new base load power stations without any of the delays usually associated **with** planning and construction. Using the cost parameters discussed earlier in this paper and assuming a demand fluctuation of **±10%,** such a planner would have provided Victoria with base load plant capable of supplying **86%** of the anticipated maximum demand with peak load plant capable of supplying the remainder. ***6%*** of annual consumption would have been met by peak load plant and the remainder by coal fired.

## A competitive pool system

Under the pool system proposed for Victoria and described above, $P$ is no longer set by a single planner, but be a group of individual firms each concerned to maximise their profits. Since these firms are to be placed in competition, it is convenient to assume that they will set their prices to recover their long-run marginal costs when bidding into the pool. It is also convenient to assume that the base-load stations, with their lower variable costs and their technical reasons for wishing to operate for long continuous periods, will make lower bids than the peak load stations. If the base load stations supply a fraction of at least $1-a$ of the peak demand, the peak load stations will be limited to a total supply volume of no more than 50% of their capacity, and their prices must reflect this inefficient use of their capital assets.

Three cases can be distinguished:

(a) The total bids from the base load stations are less than $1-a$: the peak load equipment operates continuously and the market price is that quoted by the peak load, high variable cost stations.

**(b)** The total bids from the base load stations lie inside the range $1 \pm a$: the peak load equipment operates for part of the time only, and so sets the price for part of the cycle; for the rest of the time, the pool price is equal to the marginal cost of operating the base load stations at the appropriate output level.

(c) The base load stations bid more than $1+a$**:** the whole load is carried by the base load stations, and the pool price is equal to the marginal cost of operating the highest cost base load station scheduled.

Case (c) can be disregarded in practice: the deleterious effects of operating fluctuating loads on base load equipment will cause its early and inevitable failure, and so the base load stations will not, in general, bid to cover the last fraction of demand if for no other reason than the protection of their plant.

Under case (a) the pool price is determined by the marginal cost of operating peak stations; as the bids by the base load stations fall below $1-a$ the capacity utilisation of the peak systems rises from 50% towards a maximum. This will lower the marginal cost of operating these stations and therefore the pool price. Even colluding oligopolists are unlikely to restrain production to the point that the price starts to fall, and so the price is unlikely to stay in this region until a substantial fraction of the base load plant expires from senility.

Case (b) is where peaking plant is scheduled during part, but not all of the cycle, and the price will be determined by the peak suppliers for part of the time and by the base load suppliers for the rest of the time. This is the normal operating region for a system such as Victoria's, and is examined further below.

$\lambda$ and w can be determined, given $P$ and $a$, from (5). The average price is then given by (8).

$$\bar{p}=(\lambda+Pw)\left(\frac{f_g}{\lambda}+V_g\right)+(1-\lambda-Pw)\left(\frac{f_c}{1-\lambda}+V_c\right) \quad (8)$$

When (8) is compared to (6) the conditions for the average price under a competitive pool being less than those for a public or regulated monopoly can be examined. For reasonable values of capital and other costs, $\bar{p}>$T for all valid values of $P$.

## Numerical example

**Table 1** sets out the expected pool prices using realistic values in the preceding equations.

For the reasons set out in the early part of this paper, the existence of bilateral contracts is likely to mean that the actual behaviour of the pool price will not follow this pattern. It will be seen that over the whole range of $P\ (1\pm a)$ the average pool price is above the economic cost and a surplus profit accrues to the base load generating companies. Repeating these calculations for the base price marked down to fuel cost, as might be the results of unimaginably fierce competition, still leaves the base load stations earning a surplus profit until their combined capacity bid into the pool approaches 90% of peak demand. In the USA, Chapter 11 of the bankruptcy law permits companies caught in such price wars to suspend payments on their fixed interest debt and continue trading. No such law applies in Australia, and so a period of trading below long-run marginal cost will force one or more generating companies to suspend operations and bring prices back towards profitable levels.

# Conclusion

Among the conditions necessary for the welfare optimum of neoclassical economic theory to be reached are that product markets are perfect, and that in such markets the

**Table 1 Expected Pool Prices**

| | | | | | |
|---|---|---|---|---|---|
| Capital | | | | | |
| Brown coal station | $2,500 /Kw | | | | |
| Gas turbine | $500 /Kw | | | | |
| Fuel | | | | | |
| Brown coal | $0.0028 /Kwh | | | | |
| Gas | $0.0655 /Kwh | | | | |
| **Labour (annual)** | | | | | |
| Brown coal | $7 /Kw | | | | |
| Gas | $0 /Kw | | | | |
| Finance | | | | | |
| ROI | 10% before tax | | | | |
| Depreciation | 8% | | | | |
| **Demand** | | | | | |
| Swing | 10% average to peak | | | | |
| Base capacity | 99.99% | 95% | 90% | 85% | 81.82% |
| Peak time | 1% | 35% | 53% | 73% | 100% |
| Base price | $0.0549 | $0.0556 | $0.0569 | $0.0589 | $0.0607 |
| Peak price | $1.0970 | $0.1103 | $0.0960 | $0.0893 | $0.0860 |
| Average price | $0.0720 | $0.0764 | $0.0790 | $0.0817 | $0.0860 |
| Economic cost | $0.0601 | $0.0586 | $0.0579 | $0.0577 | $0.0580 |

price will be forced, by the forces of supply and demand, to long-run marginal cost. All capital and labour is assumed, at equilibrium, to be fully employed. Neoclassical theory described trade in goods, where short-term fluctuations in demand could be evened out without any great penalty, and assumed common manufacturing technology, or at least production functions, across all suppliers.

Electricity generation is a service in which over-production is technically impossible: supply is constrained to match instantaneous demand. For this reason it is impossible for capital to be fully employed. Marginal costs must therefore be inflated to allow for the inevitable under-utilisation of capital. It is also difficult to find a common production function for the case where marginal labour costs are zero (as for gas turbine plant) or trivial (as for modem base load generating plant).

It has been suggested that the microeconomic reform of the electricity industry will lead to lower power prices due to the pressure of competition. This paper suggests that such conclusions need to be examined very carefully.